Ohio Environmental Protection Agency

Mike DeWine, Governor
Jon Husted, Lt. Governor
Laurie A. Stevenson, Director

February 6, 2019

Re: Vickery Environmental Services
Permit – Long Term
Draft for Public Comment
Underground Injection Control
Sandusky County
OHS143340001

Mr. Stephen C. Lonneman
General Manager
Vickery Environmental, Inc.
3956 State Route 412
Vickery, Ohio 43464

Subject: Draft Class I Hazardous UIC Permits to Drill:
UIC 03-72-019-PTD-I and UIC 03-72-020-PTD-I

Dear Mr. Lonneman:

Pursuant to Section 6111.044 of the Ohio Revised Code, Ohio EPA is proposing draft Class I Hazardous Underground Injection Control permits to drill. The proposal of the draft permits does not constitute the issuance of a proposed action under Section 3745.07 of the Revised Code, and the holding of the public hearing on the draft renewal permits does not constitute an adjudication under that Section and Chapter 119. of the Revised Code. Copies of the draft permits and public notice are enclosed.

Should you have any questions regarding this matter, please contact Jess Stottsberry of my staff at (614) 644-2752.

Sincerely,

Amy J. Klei, Chief
Division of Drinking and Ground Waters

Enclosures

ec: Allan Batka, U.S. EPA, Region 5
Shannon Nabors, Chief, NWDO
Elizabeth Messer, Assistant Chief, DDAGW
Lindsay Taliaferro III, UIC Unit Manager, DDGW
Jess Stottsberry, UIC Unit Geologist, DDAGW

Sandusky County

PUBLIC NOTICE

OHIO ENVIRONMENTAL PROTECTION AGENCY
ISSUANCE OF DRAFT PERMITS TO DRILL
PUBLIC INFORMATION SESSION
PUBLIC HEARING

Notice is hereby given that the Director of the Ohio Environmental Protection Agency (Ohio EPA) has issued on February 6, 2019, two (2) Draft Permits to Drill (PTDs), numbers UIC 03-72-019-PTD-I and UIC 03-72-020-PTD-I to Vickery Environmental, Inc., Vickery, Ohio. The Draft Permits are for Class I Hazardous Injection Wells Numbers 7, and 8 at the Vickery Environmental, Inc. facility located at 3956 State Route 412 in Sandusky County, Vickery, Ohio. These proposed permits have been issued in draft form by the Director pursuant to Section 6111.044 of the Revised Code.

Notice is hereby given that Ohio EPA will conduct an Information Session and Public Hearing on March 28, 2019, at 6:00PM. The information session and hearing will be held at the Sandusky County Board of Health, 2000 Countryside Drive, Fremont, Ohio.

Ohio EPA's draft PTD's are issued to meet state requirements and regulations, found in Chapter 6111. of the Revised Code and Chapter 3745-34 of the Ohio Administrative Code. The draft action proposes to allow Vickery Environmental to construct two (2) Class I Hazardous Waste injection wells. No authorization to use these wells for waste water disposal purposes is given or implied by the draft action. In order to use the wells for waste water disposal, Vickery Environmental would need to apply for and obtain a Class I permit (s) to operate from Ohio EPA.

During the information session, Ohio EPA will provide information and answer questions regarding Ohio EPA's draft actions. At the public hearing, the public may present testimony to the hearing officer. All persons are entitled to attend or be represented and give written or oral comments on the draft actions at the public hearing.

Written comments on the draft permits may be submitted at the hearing or mailed to Ohio EPA, Division of Drinking and Ground Waters, Attn: UIC Section Supervisor, P.O. Box 1049, Columbus, Ohio 43216-1049. **All comments received on or before April 1, 2019, will be considered part of the administrative record and will be considered prior to the final decision on issuance of the permits.**

Persons desiring to receive notice of further proceedings and other information relating to the above referenced permits may contact Ohio EPA, Division of Drinking and Ground Waters, P.O. Box 1049, Columbus, Ohio 43216-1049, Attn: Jess Stottsberry, (614) 644-2752. Copies of the draft permits may be inspected at the Birchard Public Library of Sandusky County, 423 Croghan Street, Fremont, OH; at the Ohio EPA's Northwest District Office, 347 North Dunbridge Road, Bowling Green, OH, (419) 352-8461; or at Ohio EPA, Central Office, 50 West Town Street, Suite 700, Columbus, OH, (614) 644-2752, by first contacting Jess Stottsberry.

Ohio Environmental Protection Agency

DIVISION OF DRINKING AND GROUND WATERS

UNDERGROUND INJECTION CONTROL PERMIT TO DRILL: CLASS I HAZARDOUS WELL

Ohio Permit No.: UIC 03-72-019-PTD-I

Date of Issuance:
Effective Date:

Date of Expiration: 4 years after issuance if issued

Name of Applicant:	Vickery Environmental, Inc.
Facility Location:	3956 State Route 412 Vickery, Ohio 43464
Mailing Address:	3956 State Route 412 Vickery, Ohio 43464
County:	Sandusky
Township:	Riley
Section:	Section 26
Well Name:	VEI Disposal Well No. 7
Well Location:	41°22'9" N/-82°58'55" W
Total Depth:	+/- 2,900′ Total Vertical Depth to Mt. Simon (measured from Kelly Bushing (KB) height). Ground level elevation estimated at 607′ above sea level.

The above, named permittee is hereby issued a Permit to Drill for the above described underground injection well pursuant to Chapter 3745-34 of the Ohio Administrative Code.

Issuance of this Permit to Drill does not constitute expressed or implied assurances that if constructed and/or modified in accordance with those specifications and/or information accompanying the permit application, the permittee will be granted an operating permit(s).

The permittee, its employees, subsidiaries, successors, contractors, and others acting in concert with the permittee are solely responsible to maintain control of the well at all times and will ensure at all times, the drilling and construction of the well will be protective of human health and the environment. This Permit to Drill is issued subject to the conditions provided in the permit and all applicable provisions of Chapter 6111. of the Ohio Revised Code and the rules adopted thereunder; of Chapter 3745-34 of the Ohio Administrative Code; and all applicable provisions of 40 C.F.R. Parts 124, 144, and 146 which are also hereby incorporated. Nothing in this Permit to Drill should be deemed to relieve the permittee of any obligations under applicable local, state, or federal laws. Where these incorporated provisions conflict with the expressed terms and conditions, the expressed terms and conditions shall control.

This permit and the authorization to drill shall expire at midnight, unless terminated, on the date of expiration indicated.

Laurie A. Stevenson, Director
Ohio Environmental Protection Agency

TABLE OF CONTENTS

Page

PART I – General Permit Conditions

A. Effect of Permit 1

B. Permit Actions 1

C. Duration of Permit 1

D. Severability 2

E. Confidentiality 2

F. Duties and Requirements 2

G. Inspection and Entry 3

H. Analysis of Data 4

I. Financial Responsibility 4

J. Plugging and Abandonment 4

K. Duty to Provide Information 5

PART II – Well Specific Conditions

A. Construction Requirements 6

B. Requirements for Drill Cutting and Cores 7

C. Geophysical Well Logging 8

D. Formation Testing 9

E. Formation Testing Requirements 9

F. Injection Pressure Limitations 10

G. Injection Formation Stimulation Prerequisite 11

H Record Requirements 11

I. Well Closure Plan 12

ATTACHMENTS

A. Closure Plan

B. Geotechnical Information

C. Well Construction

D. Surface and Bottom Hole Pressure Limitations

E. Corrective Action

PART I
GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

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

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

B. PERMIT ACTIONS

1. Modification, Revocation, Reissuance and Termination. The Director may, for cause or upon request from the permittee, modify, revoke, and reissue, or terminate this permit in accordance with Ohio Administrative Code (OAC) Rules 3745-34-07, 3745-34-23, and 3745-34-24, and 3745-34-26. Also, the permit is subject to OAC Rule 3745-34-27(A). Changes in construction may be approved as minor modifications for cause as specified in OAC Rule 3745-34-25. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated non-compliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. 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 3745-34-25(D) as applicable.

C. DURATION OF PERMIT (OAC Rule 3745-34-21(D))

This Permit to Drill shall terminate within eighteen (18) months of the effective date if the permittee has not undertaken a continuing program of construction or has not entered into a binding contractual obligation to undertake and complete construction within a reasonable time.

D. 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.

E. 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, 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 at the permitted facility.

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

2. 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. Reporting Requirements

   a. Pursuant to OAC rule 3745-34-27(A)(1), changes in construction plans during construction may be approved by the Director as minor modifications (OAC Rule 3745-34-25). No such changes may be physically incorporated into construction of the well prior to approval of the modification by the Director.

   b. Written notice of any planned physical alterations to the well shall be given to Ohio EPA ten (10) days prior to commencement of any alteration. A shorter time period may be approved by the Director. Furthermore, the permittee shall provide justification for any planned physical alterations to the permitted well. Prior to implementation of any alteration, the permittee shall have written approval for the proposed alteration from Ohio EPA.

c. The permittee shall report to the Director any non-compliance which may endanger health or the environment. All available information shall be provided orally within twenty-four (24) hours from the time the permittee becomes aware of such noncompliance. The following events shall be reported orally within twenty-four (24) hours:

   i. Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water.
   ii. Any non-compliance with a permit condition, or malfunction of the drilling equipment, which may cause fluid migration into or between underground sources of drinking water.

d. A written submission shall also be provided within five (5) working days of the time the permittee becomes aware of the circumstances of such non-compliance. The written submission shall contain the following:

   i. A complete description of the non-compliance and its cause; and
   ii. The time, date, and duration of the period of non-compliance; and
   iii. If the non-compliance has not been corrected, the anticipated time it is expected to continue; and
   iv. Identification and quantification (including sample results when available) of all substances released to the environment or involved in the incident or event; and
   v. A description of all remedial measures taken or to be taken; and
   vi. A description of the extent of contamination or damage to the environment; and
   vii. Any monitoring or other documentation available about the incident; and
   viii. A description of the steps taken or planned to reduce or eliminate the possibility of recurrence of the non-compliance.

4. Injection The permittee may not commence injection of waste into the well until a Permit to Operate application has been submitted to Ohio EPA for review and final approval for a Permit to Operate has been issued by the Director of Ohio EPA. Any other injection required during well testing to acquire data or to perform a well stimulation is excluded from this stipulation but shall be conducted in accordance with a plan(s) approved, in advance, by Ohio EPA and will be subject to all other provisions of this permit.

G. INSPECTION AND ENTRY

1. The Ohio EPA shall have unlimited authority and access to witness or to inspect for compliance with this permit; all drilling, testing, logging, and construction of the well. The permittee shall submit a schedule of such activities in writing to Ohio EPA prior to commencement. The permittee shall notify Ohio EPA at a minimum of twenty-four (24) hours prior to any logging or well tests.

2. The permittee shall inform Ohio EPA of the progression and scheduling of drilling and testing **daily**. A written driller's report, containing information specified in Part II (H)(3) of this permit shall be submitted daily in an electronic format. For the purpose of this permit to drill provision, **daily** is defined as occurring at least once every calendar day.

H. ANALYSIS OF DATA

1. Field results from all well logging shall be submitted within ten (10) days of completion of the activity. A field log shall be made available the day of the logging at Ohio EPA's request.

2. The following results obtained during construction of the well, along with a technical appraisal of the results, shall be submitted to the Ohio EPA, in the form of a report (duplicate) or within an application for a Permit to Operate (five paper copies required), no later than sixty (60) days after the well drilling and testing is completed, including:

   a. All geophysical logs, well completion, mud log, well testing, core data, and any other technical data; and,

   b. Results of injection and reservoir testing. These results are to include information on effective reservoir thickness, reservoir pressure build-up, and anticipated radial movement of the waste.

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

1. The permittee has provided a demonstration of adequate financial resources to plug and abandon the four existing wells. Adequate financial assurance for the two proposed wells must be established and approved by Ohio EPA prior to the commencement of drilling. Cost estimates to cover closure and post-closure costs of the two additional wells proposed is included within Attachment A of this Permit to Drill.

2. The permittee shall notify Ohio EPA within ten (10) days of bankruptcy or insolvency (in any form) of the permittee or the entity providing financial assurance. In addition, notice shall be given within ten (10) days of event if any bonds, insurance or other security submitted under this paragraph lapse, are transferred, or are otherwise compromised.

3. The permittee is required to establish, maintain financial responsibility and resources to close, plug, and abandon the injection well. The obligation to maintain financial resources to close, plug, and abandon the well survives the termination of this permit.

4. During the operating life of the facility, the permittee shall keep on file at the facility a copy of the latest closure and post-closure cost estimates prepared in accordance with OAC Rules 3745-34-60 and 3745-34-61.

J. PLUGGING AND ABANDONMENT (OAC Rule 3745-34-36)

1. If plugging and abandonment of this well is required, then the well shall be plugged and abandoned in accordance with the plans found in Attachment A of this permit. The plan is subject to final of approval by Ohio EPA. The requirement to maintain and implement the plugging and abandonment plan is enforceable until plugging and abandonment are completed in accordance with the plan.

2. The permittee remains responsible for this well and any environmental impact caused by the drilling or use of the well, whether authorized or unauthorized, at all times, including after plugging and abandonment of the well.

3. In accordance with OAC rule 3745-34-60(B), the permittee shall notify the Director at least sixty (60) calendar days before the anticipated date of plugging and abandonment of the well, unless a shorter notice period is approved by the Director.

4. Within twenty-four (24) months of well completion, the permittee is required to submit to Ohio EPA an application for a Permit to Operate that, at a minimum, meets all requirements of OAC Rule 3745-34-15 to be considered a complete application. If a complete application for a Permit to Operate is not submitted to Ohio EPA within this time frame, the permittee is required to begin implementation of its current and approved closure plan.

K. DUTY TO PROVIDE INFORMATION

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

Part II
WELL SPECIFIC CONDITIONS

A. CONSTRUCTION REQUIREMENTS (OAC Rule 3745-34-54)

1. At a minimum, the permittee shall construct the well in accordance with the construction standards of OAC Rule 3745-34-54. All well materials shall be compatible with any fluids with which the materials may be expected to come into contact and designed for the life expectancy of the well.

2. The permittee shall follow drilling and construction procedures as set forth in the permittee's approved application, including all revisions submitted to Ohio EPA or as otherwise specified within this Permit to Drill. Proposed casing program and cementing procedures are included in Attachment C of this Permit to Drill. Appropriate mechanical and engineering practices shall be applied to ensure that the well pressure is controlled at all times.

   a. Only potable water shall be used for mixing in drilling or completion operations.

   b. Conductor casing shall meet or the standards as established in the Drilling Plan section of the permit applications. The conductor shall be installed at a depth which adequately allows emplacement of the surface casing.

   c. Surface casing shall, at a minimum, extend 100 feet into the confining bed below the lowermost USDW and be cemented to surface using a minimum of 120% of the calculated annular volume.

   d. Centralizers shall be placed to ensure adequate cementation of the casing and ensure protection of the USDW. At a minimum, surface casing shall be centralized at the shoe and on every second joint thereafter.

   e. Before drilling below the surface casing, a blowout preventer, control head or other connections shall be installed to keep the well pressure under control at all times.

   f. Deviation checks shall be performed at sufficiently frequent drilling intervals to assure the measurements needed to calculate and plot the well path. The measured depth, inclination, and azimuth shall be recorded at each survey point. The data shall be used to monitor the well path, to determine the exact bottom hole location, and to assure that no vertical avenues are created which would allow fluid migration pursuant to OAC Rule 3745-34-55(A)(1).

   g. Long string casing with a sufficient number of centralizers shall extend into the top of the Mt. Simon Formation and be cemented to surface. The cement volume shall be a minimum of 120% of the calculated annular volume.

   h. Long string casing centralizers shall, at a minimum, satisfy specifications established in the permit applications. Centralizers shall be placed to ensure adequate cementation of the casing and to ensure that the lowermost USDW is protected. At a minimum, each joint of the bottom 500 feet of the long string casing shall be centralized, and subsequent centralizers shall be placed on every second joint to the surface thereafter.

i. Neither the cement nor associated cementing equipment shall be subject to the resumption of drilling until the cement has developed sufficient compressive strength to support the casing and restrict fluid movement between formations. The cement bond of each casing string shall be demonstrated by an approved bond log.

j. The permittee shall obtain representative samples of the cement mixture and additives for each cementing operation. At a minimum, samples shall be collected at intervals of approximately 25%, 50%, 75%, and 95% of the total volume used in each cementing operation. Laboratory analyses shall be performed for at least the following:

   i. Compressive strength;
   ii. Permeability; and
   iii. Fluid loss.

3. Under no circumstances shall the Precambrian Middle Run Formation be penetrated during drilling operations.

B. REQUIREMENTS FOR DRILL CUTTINGS and CORES (OAC Rule 3745-34-55)

1. Drill cuttings shall be sampled and collected at 10′ intervals, at a minimum, except if whole cores are being collected from the interval. The cuttings shall be representative of the drilled intervals and be placed in appropriately labeled sample bags. Special attention and monitoring for hazardous waste conditions will be required for drill cuttings and produced fluids when the top of the injection zone is encountered and through total depth. The drill cuttings from the injection zone should be treated and disposed per hazardous waste requirements.

2. The permittee is responsible for care and security of well cuttings samples and any core that is obtained. If requested, drill cuttings and cores shall be delivered to the Ohio Department of Natural Resources' Core Repository.

3. OAC Rule 3745-34-55(B) requires that whole or sidewall cores of the confining and injection zones be taken. The permittee shall ensure that any extracted core is representative of the intended interval and that coring operations result in optimum core uniformity and recovery. Procedures for testing the core(s) shall be submitted to Ohio EPA for prior approval, if applicable. OAC Rule 3745-34-55(D)(3) requires that the permittee submit information detailing the physical and chemical characteristics of the confining and injection zones, including an accurate description of the fluids present in these zones.

   At a minimum, the following approximate intervals be shall be cored unless otherwise approved by the Director:
   - 40 feet above the top of the Knox to 40 feet below the top of the Conasauga;
   - 40 feet above the base of Conasauga to 40 feet below the top of the Rome;
   - 40 feet above the top of the Mt. Simon to Total Depth (2,900′ proposed)

   All depths are to be referenced from true vertical depth.

   The Director may require additional coring should it be determined the cores taken under this permit are not adequate for satisfying the requirements of OAC Rule 3745-34-55.

C. GEOPHYSICAL WELL LOGGING REQUIREMENT (OAC Rule 3745-34-55)

At a minimum, the following electric and geophysical well logs (or equivalent logs) shall be performed unless otherwise approved by the Director: (All procedures must be pre-approved by Ohio EPA).

1. Prior to the installation of the surface casing:
   a. Gamma Ray;
   b. Spontaneous Potential;
   c. Lateral Induction Resistivity;
   d. Compensated Neutron Density;
   e. Compensated Formation Density; and,
   f. Caliper.

2. After surface casing has been set and cemented:
   a. Gamma Ray;
   b. Temperature;
   c. Variable Density; and
   d. Cement Bond.

3. Prior to installation of the long string casing:
   a. Gamma Ray;
   b. Spectral Gamma Ray;
   c. Photo electric;
   d. Spontaneous Potential;
   e. Lateral Induction Resistivity;
   f. Nuclear Magnetic Resonance (NRM);
   g. Compensated Neutron;
   h. Compensated Formation Density;
   i. Temperature;
   j. Fracture Identification;
   k. Long Spaced Sonic; and
   l. Caliper.

4. After long string casing has been set and cemented:
   a. Gamma Ray;
   b. Temperature;
   c. Variable Density;
   d. Cement Bond; and,
   e. Casing Inspection.

5. To be considered approvable for a Permit to Operate, the permittee shall provide a schedule and plan for Ohio EPA review and approval at least thirty (30) days prior to testing, including the following:
   a. Baseline Differential Temperature Survey;
   b. Annulus Pressure Test;
   c. Radioactive Tracer Survey;
   d. Post-Injection Differential Temperature Survey; and,
   e. Bottom Hole Pressure Falloff Test.

6. The above electric and geophysical well log requirements do not limit or relieve the permittee from other or additional logging or testing requirements which may be deemed necessary by the Director. The permittee shall notify Ohio EPA a minimum of twenty-four (24) hours prior to any well logging. This requirement does not apply to the mud log which will be performed continuously from spud point to total depth.

   Should cementing procedures or logging results indicate potential for an inadequate cement job, the permittee shall conduct all necessary operations to ensure a quality cement job.

D. FORMATION TESTING

1. In accordance with OAC rules 3745-34-37(E), 3745-34-38(A)(1), and 3745-34-55(D), the permittee shall provide an adequate demonstration of the fracture gradient and the fracture initiation, propagation, and closure pressures. An adequate demonstration is required prior to issuance of a Permit to Operate. The permittee shall collect all data necessary to provide a conclusive demonstration. The permittee must obtain approval from Ohio EPA for all procedures prior to this demonstration.

2. Should the permittee choose to perform an injectivity test, to fulfill the requirements of OAC Rule 3745-34-55(E), the test shall be conducted using an Ohio EPA approved fluid and method.

3. Should the permittee choose to perform a pressure fall-off test, the permittee shall provide a plan for Ohio EPA review and approval at least thirty (30) days prior to testing.

4. The above minimum testing requirements do not limit or relieve the applicant from additional testing if it is determined by Ohio EPA that additional testing is necessary. The permittee shall notify Ohio EPA at a minimum of twenty-four (24) hours prior to any formation testing.

E. FORMATION TESTING REQUIREMENTS

1. The permittee shall recover stabilized fluid samples in a manner that shall maximize accurate measurement of pH and chemical constituents. The permittee shall record the following minimum measurements after a representative wellbore volume has been purged, to ensure that formation parameters have stabilized:
   a. pH;
   b. Specific Gravity; and
   c. Specific Conductance.

2. Upon twenty-four (24) hour prior notice, a split sample of each recovered fluid sample shall be provided to Ohio EPA for analysis if requested. All sampling depths will be agreed upon by Ohio EPA prior to sampling.

3. All fluid samples recovered from the confining and injection zones shall be evaluated for a minimum of the following:
   a. Specific Gravity;
   b. Specific Conductance;
   c. Temperature;
   d. pH;
   e. Total Suspended Solids;
   f. Total Solids;
   g. Total Organic Carbon;
   h. Chlorides;
   i. Sulfates;

j. Sulfide;
k. Viscosity;
l. Dissolved Oxygen;
m. Alkalinity;
n. Acetone;
o. Aluminum, Total;
p. Arsenic, Total;
q. Barium, Total;
r. Benzene;
s. Cadmium;
t. Calcium, Total;
u. Chlorobenzene;
v. 1, 2-Dichloroethane;
w. Chromium, Total;
x. Copper, Total;
y. Ethylbenzene
z. Flourides;
aa. Iron, Total;
bb. Lead, Total (TCLP if > 5.0 mg/l);
cc. Magnesium, Total;
dd. Manganese, Total;
ee. Mercury;
ff. Methyl Isobutyl Ketone;
gg. Nickle, Total;
hh. Nitrates;
ii. Potassium, Total;
jj. Selenium;
kk. Silver;
ll. Sodium, Total;
mm. Strontium, Total;
nn. Toluene;
oo. Trichloroethylene;
pp. Xylene;
qq. Zinc, Total;
rr. BTEX, Total; and
ss. Pyridine.

4. In accordance with Ohio Revised Code Section 6111.043(D), the permittee shall submit to the Director any information or test results that the Director determines is necessary to more adequately define hydrogeologic conditions at the site of the well and to protect the lowermost USDW.

F. INJECTION PRESSURE LIMITATION (OAC Rule 3745-34-56)

1. Except during stimulation or testing approved in advance by Ohio EPA, injection pressure at the wellhead shall not exceed a maximum which shall be calculated in such a way as to assure that the pressure in the injection zone 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 a USDW. Refer to Attachment D for pressure limitation calculations for both bottom hole and surface pressures.

2. Injection between the outermost casing protecting USDWs and the wellbore is strictly prohibited. At no time shall injection occur into any formation without prior approval from Ohio EPA.

3. No waste water shall be injected into this well prior to receipt of a final Permit to Operate issued by the Director of Ohio EPA and any conditions set forth therein.

4. Injection necessary to conduct well testing or stimulation shall be conducted in accordance with limitations established in Part I(F)(4) of this permit.

G. INJECTION FORMATION STIMULATION PREREQUISITE

1. Hydraulic fracture stimulation of the injection formation is prohibited unless the permittee has secured written approval from Ohio EPA. To receive authorization from Ohio EPA to fracture stimulate the injection formation, the permittee must demonstrate that such stimulation shall not initiate fractures in the confining zone or cause movement of injection or formation fluids into a USDW.

2. If the permittee chooses to perform an acid stimulation of the injection formation the permittee must submit a plan to Ohio EPA for approval. The permittee must demonstrate that the injection pressure does not exceed the formation fracture pressure.

H. RECORD REQUIREMENTS

1. Records of all sampling, testing, and analysis shall include:
   a. The date, exact place, and time of sampling, testing, or measurements;
   b. The individual(s) who performed the sampling, testing, or measurements;
   c. A precise description of sampling and testing methodology and the handling of samples thereof;
   d. The date(s) analyses were performed;
   e. The name(s) of individual(s) who performed the analysis;
   f. The analytical techniques or methods used; and
   g. The results of the analyses.

2. Analysis of fluid samples shall comply with applicable analytical methods cited and described in 40 CFR 136.3 or in Appendix III of Part 261.

3. At all times throughout the drilling and construction of the well, the permittee shall maintain a drilling record at the well site. At a minimum, the drilling record shall note and record the following:
   a. Current depth;
   b. Drilling rate of penetration (drilling time log);
   c. Lithology;
   d. Size of drill bit;
   e. Water/fluid bearing zone(s);
   f. Oil and gas shows;
   g. Lost circulation zone(s);
   h. Deviation survey results, including bottom hole location;
   i. Drilling fluid information, at a minimum shall include:
      i. Depth;
      ii. Weight;
      iii. Viscosity;
      iv. Fluid loss test;
      v. Specific conductance; and
      vi. pH.

4. Ohio EPA shall be granted access to view, examine, take notes from and/or copy the drilling record at all times. Within thirty (30) days of completion of drilling and construction operations, a true copy of the drilling record shall be delivered to Ohio EPA.

5. The permittee shall inform Ohio EPA of the progression and scheduling of drilling and testing **daily**. A written daily driller's report shall be submitted electronically. At a minimum, the daily drilling report shall contain the following information:

   a. General information:
      i. Date and time of report;
      ii. Well depth;
      iii. Formation;
      iv. Lithology;
      v. Comments; and
      vi. Name/title of person preparing the report.

   b. Daily drilling and completion report:
      i. Report date;
      ii. Spud date;
      iii. Current drilling depth;
      iv. Present operation (e.g. drilling, waiting on cement, etc.);
      v. Casing/Cementing data – at a minimum date set, depth, casing size diameter, centralizer locations, sacks of cement;
      vi. Bit data – bit number, size, type, hours in use, footage drilled, weight on bit, revolutions per minute;
      vii. Mud data – at a minimum, items in Part II (H)(3)(i) of the permit to drill; and,
      viii. Summary of activities since the previous report.

   c. Activities, including those outlined in the drilling plan, projected to occur during the next twenty-four (24) hours.

I. WELL CLOSURE PLAN

1. At a minimum, the permittee shall plug and abandon the well in accordance with the standards set forth in OAC Rules 3745-34-36, 3745-34-39, and 3745-34-60.

2. The permittee shall inform Ohio EPA of their intentions to plug and abandon the well at least sixty (60) days prior to the scheduled plugging date. The permittee shall obtain Ohio EPA approval of the closure plan prior to initiating plugging and abandonment operations.

3. The permittee shall provide a report of the plugging and abandonment to Ohio EPA within sixty (60) days after completion of the plugging and abandonment activities.

Attachment A

I. Closure Plan

II. Closure Cost Estimate

Attachment A

I. Closure Plan

12.0 PLUGGING AND ABANDONMENT PLAN

12.1 PLUGGING AND ABANDONMENT

The typical plugging and abandonment procedure to be applied to the Vickery wells is as follows:

1. Perform a 48-hour injection/48-hour falloff test (ambient monitoring) of the formation using the plant's injection pumps and using a surface readout downhole pressure gauge, in accordance with OAC Rule 3745-34-60(D)(1).

   The actual length of the injectivity/falloff test must be approved in advance by Ohio EPA.

   OAC Rule 3745-34-60(D)(2) requires that "Prior to well closure, the owner or operator of a class I hazardous waste injection well shall conduct appropriate mechanical integrity testing 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:

   a) Pressure tests with liquid or gas; *or*
   b) Radioactive tracer surveys; *or*
   c) Noise, temperature, pipe evaluation, or cement bond logs; *or*
   d) Any other test required by the director.

   An annulus pressure test, radioactive tracer log, multi-pass temperature log, and a casing inspection log is planned. The mechanical integrity tests must be approved in advance by Ohio EPA.

2. Increase the tubing-casing annulus pressure to greater than 1,000 psi and allow the pressure to stabilize. Monitor and record the pressure for one hour. If the pressure loss is less than 3% in a one-hour period, the test will be considered successful.
3. Perform a multi-pass temperature decay log, logging from total depth to surface. Fluid

injected during the pumping phase of the test must be at least 10° warmer or cooler than the ambient temperature in the well.

4. Perform radioactive tracer logging consisting of an initial base gamma ray pass, two point statistical check, two series of ejections and subsequent chase passes, two time drive surveys and a final base gamma ray pass.

5. Move in and rig up a well service unit and ancillary equipment. Pump three wellbore volumes of fresh water to flush the well, then pump 10 lb/gal sodium chloride brine to kill the well.

6. Remove the well head and install a blow out preventer (BOP). Decontaminate and/or dispose of the well head in an appropriate manner.

7. Connect a 2-inch line from the tubing-casing annulus valve to a holding tank. Pick up on the tubing to pull the seal assembly from the polished bore receptacle. Pump brine down the tubing and up the annulus to remove the diesel fuel well cap from the annulus. Catch the diesel in the holding tank.

8. After all diesel fuel has been pumped from the well, cease pumping and allow the pressure in the tubing and the annulus to equalize.

9. Pull the fiberglass tubing and the seal assembly from the well and decontaminate and/or dispose of in an appropriate manner. Perform Casing inspection log after fiberglass tubing has been removed.

10. Pick up 18 joints of the 2-7/8" fiberglass tubing removed from the well and run into the well on workstring tubing. Tag plug back total depth (PBTD) with the fiberglass tubing. Balance a plug of Epseal acid resistant cement from PBTD to a point above the top of the

Knox formation (depth varies from 2330 ft to 2360 ft RKB among the four remaining wells).

11. Pull out of the well with the tubing and decontaminate and/or dispose of the fiberglass tubing as above. Wait a minimum of 48 hours for the Epseal cement to set.

12. Run the workstring into the well and tag the top of the Epseal plug. Close the BOP and test the plug to 500 psi. If the pressure loss is less than 3% in a one-hour period the test will be considered successful.

13. A manufacturing quality certificate from the maker of the cement will be provided to OEPA prior to the start of cementing operations.

Fill the casing with Class "A" cement, using the balanced plug method, from the top of the Epseal plug to the surface. A cementing truck with continuous density monitoring equipment will be utilized. Take a sample of the cement from the initial 20% of the stage volume and from the final 20% of the stage volume to be used for curing time determination. Wait on cement for at least 4 hours between plugs and tag each plug prior to spotting the successive plug.

14. Cut off the wellhead and casing three feet (3') below ground level and weld a steel plate onto the top of the casing. The plate will have a steel tag with the following inscribed:

Vickery Environmental, Inc.
Hazardous Waste Disposal Well
Ohio EPA UIC # ------------
Plugged: (Date)

15. Rig down and move off the service unit and ancillary equipment. Decontaminate and

dispose of any remaining contaminated well equipment.

16. Prepare a report of the plugging and abandonment operations for submittal to the OEPA within the time frame and containing the information specified in OAC Rule 3745-34-60 (C).

NOTE: All cement volumes will be calculated for each specific well.

* The proposed P&A procedure assumes that injection activities will be ceased for all wells, and then the wells will be plugged. If an individual well is to be plugged, but injection continued in other wells, a P&A procedure similar to that utilized previously for the #1 and #3 wells would be followed.

** Depths will be referenced to original RKB. The volume of Epseal specified is calculated to fill the well to the indicated point relative to RKB assuming there is no fill in the well. Any fill present would only cause the specified volume of Epseal to fill the well to a higher level, and cause a correspondingly lesser amount of Class A cement to be required. No excess volume is included in the above calculated values.

*** Assumes Class A cement is mixed to 15.6 lbs./gal.. This results in 1.18 cu. ft. of cement being produced per sack mixed.

Attachment A

II. Closure Cost Estimate

2019 FA Update with UIC PTD changes

SECTION 4

INJECTION UNIT CLOSURE COST ESTIMATE

CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
INJECTION WELLS AND KNOX KERBEL WELL PLUGGING AND ABANDONMENT. RIGS, DRILLING, MITs AND MUD FOR ~~4~~6INJECTION WELLS AND ONE DEEP MONITORING WELL @ ~~$353,484~~$385,000/WELL	~~5~~7	~~$353,484~~ $385,000	~~$1,767,420~~ $2,695,000
DISPOSAL OF TUBING AND SEALS, ~~24~~ 36TONS @ ~~$0.13~~ $0.20/LB	~~48,000~~ 72,000	~~$0.13~~ $0.15	~~$6,240~~ $10,800
ANNULUS FLUID DISPOSAL ~~8,000~~ 12,000 GALLONS @ $0.71GAL	~~8,000~~12,000	~~$0.71~~ $0.77	~~$5,680~~ $9,240
PLUGGING AND ABANDONMENT OF LOCKPORT WELL @$42,882	1	$42,882	$42,882
DISPOSAL OF WATER GENERATED FROM ABANDONMENT @ 10,000 GALLON PER WELL, ~~5~~7 WELLS @ $1.00/GAL	~~50,000~~ 70,000	$1.00	~~$50,000~~ $70,000
WATER GENERATED FROM ABANDONMENT OF LOCKPORT WELL @ 4000 GALLON @ $1.00/GAL	4,000	$1.00	$4,000
TOTAL OF INJECTION UNIT CLOSURE			~~$2,043,430*~~ $2,831,922

~~***2018 Inflation adjusted total cost + 1.8% Inflation Adjustment**~~

Attachment B

I. Geology Description

II. Seismic Discussion

Attachment B

I. Geology Description

5.0 GEOLOGY

5.1 INTRODUCTION

The siting of Class 1 hazardous waste wells is limited to areas that are geologically suitable. Geologic suitability is based on an analysis of the regional and local geology. Vickery has previously studied in detail both the regional and site specific geology. This was included in Attachment B of the July 5, 1994 UIC Permits to Operate and is included with the previous permit copy in Attachment A of this document. Therefore, only a very brief summary of the regional and local geology is included here.

5.2 REGIONAL GEOLOGY

The stratigraphy of Ohio is comprised of Paleozoic carbonate and clastic rock units unconformably overlying a Precambrian basement. The Paleozoic units are in turn overlain by a relatively thin veneer of Pleistocene glacial drift and localized Holocene sediments. Figure 5-1 is a geologic time scale showing the relationship of various geological units along with approximate formation ages. Figure 5-2 indicates the stratigraphic equivalency of formation names which may be encountered in the literature when working in this region, and general formation lithology.

Structurally, Ohio occupies a relatively high position located between three major basins. Figure 5-3 shows the states location between the Michigan Basin, Illinois Basin and the Appalachian Basin. The principle structural features in Ohio are indicated on Figures 5-4, 5-5 and 5-6. The East Continent Rift Basin (ECRB) depicted on Figure 5-7 has only relatively recently been named and described as an addition to the major basement structural features of the region. Figure 5-8 shows the location of the Seneca Geophysical Anomaly to the southwest of the Vickery site. The anomaly is geophysically a strong magnetic positive and a relative gravity minimum. This figure also depicts the location of basement related structures such as faulting, the ECRB and the Grenville Front Tectonic Zone boundary. Reactivation of movement along zones of weakness aligned with basement faulting may be a factor in controlling faulting in the Paleozoic section.

5.2.1 Structure

In Ohio, the present configuration of the basement surface is the result of uplift and erosion during late Precambrian time, followed by burial in a sedimentary cover and warping during the Paleozoic. The Cincinnati Arch and the Findlay Arch should not be considered as one continuous structure. They each lose their identity on the Ohio-Indiana platform.

Figure 5-9 is a structure contour map on the Precambrian unconformity surface by Baranoski(2002) which integrates subsurface well control and seismic data where available. The map is based on a total of 310 well control points, of which 207 are within Ohio. It is interesting to note that the Precambrian structure is generally shown to be more complex in areas of higher density well control or seismic coverage. The more complex contouring is likely representative of the Precambrian surface overall, but the scarcity of control in many areas makes only a depiction of the general dip rates and direction possible. Figure 5-10 is a cross section enlarged from Baranoski's map. It shows the structural configuration on an east-west traverse across Ohio. Additional information regarding the Precambrian surface underlying the Vickery site is included in the local geology portion of this document.

Faults and folds within the basement rocks can be inferred from the distribution of rock types coupled with gravity, magnetic and seismic data. Figure 5-11 shows that the upper surface of the Precambrian in the western third of Ohio consists of intrusive and extrusive igneous rocks of the East Granite-Rhyolite Province while the surface in the eastern two-thirds of the state consists of Grenville Provence medium grade metamorphic rocks. The Vickery site is located in the Grenville Province approximately 40 miles east of the Grenville Front.

The ECRB is believed to be bounded on the east by the Grenville Front and on the west by block faulting. Gravity and magnetic data suggest the basin is connected to the Midcontinent Rift System in southern Michigan. Figure 5-12 shows the location of the known Midcontinent Rift System. Structural interpretations of seismic data indicate the ECRB predates the Grenville Orogeny and has been partially overridden by the Grenville thrust sheets from the east. The age of the ECRB is somewhat uncertain, but is certainly Proterozoic, and, based on structural relationships, cannot be as young as Cambrian. (Drahovzal, et. al., 1992). Magnetic and gravity data along the ECRB are depicted in Figures 5-13 and 5-14, respectively. The exact extent of the ECRB is uncertain, especially to the north, south and west.

Figure 5-15 shows the regional structural configuration on the top of what was called the Eau Claire by Sherrow in 1987. Figure 5-16 shows the regional structure on the top of the Knox constructed by Janssens (1973)

5.2.2 Stratigraphy

In 1989, drilling of a continuously cored stratigraphic test well by the Ohio Department of Natural Resources, Division of Geological Survey in Warren County has indicated the existence of a thick sedimentary sequence of lithic, conglomeratic sandstone below the Mt. Simon Sandstone. This sequence is named the Middle Run Formation. This sequence is the basin fill of a failed rift valley (the ECRB noted previously). The Middle Run Formation is not present beneath the Vickery site.

The Middle Run Formation was originally described by Shrake et. al. (1990). The formation is very homogeneous at its type location and consists of red to grey, fine to medium grained thickly bedded lithic sandstones. Siltstones and shales generally make up less than 10 percent of the formation volume. The Middle Run is unconformably overlain in most locations by the Mt. Simon Sandstone. Basalt has been identified both within and overlying the sandstones of the Middle Run Formation. (Drahovzal, et. al., 1992)

Figure 5-17 is a partial stratigraphic column depicting the position of the Middle Run

Formation. Figure 5-18 shows the lithology in wells thought to have penetrated the Middle Run Formation.

Cambrian and Lower Ordovician rocks, bound below by the Precambrian and above by the regional Knox Dolomite unconformity, form an extensive deposit on the midcontinent craton. Figure 5-19 shows the generalized stratigraphic correlation chart for Cambro-Ordovician formation across Ohio as derived by Janssens.

The Mt. Simon Sandstone was deposited unconformably across an extensive area on the Precambrian basement surface. The formation or its lithologic equivalents presently extend from the Appalachian Mountains to eastern Missouri, and from Tennessee into Canada. The thickness of the Mt. Simon Sandstone across a four state area is shown in Figure 5-20. Figure 5-21 shows the Mt. Simon Sandstone thickness within the State of Ohio. Within Ohio, the Mt. Simon Sandstone thickness varies from near zero in Pickaway County where it is believed to have never been deposited, to about 400 ft along the state western border. This complex Precambrian surface is not uncommon across Ohio as documented by 20 wells in Ohio drilled into Precambrian paleotopographic highs (Baranoski, 2002)." Based on discussions with staff of the Division of Geological Survey, the Mount Simon Sandstone thins to zero thickness approximately 20 miles southwest of the Vickery facility in Seneca County, Hopewell Township. This observation was made based on the review of sample cuttings and the well log for a well installed in August 1979 (Well Permit #214).

In Ohio, the Mt. Simon Sandstone consists of friable fine to coarse grained sandstone, conglomeratic sandstone and sandy conglomerate. The sand is generally poorly sorted, but individual beds can be well sorted. Medium and larger sized sand grains are usually rounded and frosted. Color ranges from clean to pink or yellowish pink. Dark brownish red staining is present in some locations. The main body of the Mt. Simon Sandstone is poorly cemented, but siliceous cements are noted in some locations.

The Mt. Simon Sandstone is regionally overlain by the Rome Formation (primarily dolomite) in the eastern two-thirds of Ohio and the Eau Claire Formation (primarily glauconitic siltstone and fine grained sandstone), in the western third of Ohio. The middle interval of the Rome contains a sandy facies in the central portion of Ohio, relative to an east-west transect. The Rome and Eau Claire are in a complex facies relationship across Ohio as was shown previously in Figure 5-19. A schematic cross section in central Ohio is presented as Figure 5-22 showing the facies changes within the Rome in a north-south direction. The location of the Vickery facility is shown on Figures 5-19 and 5-22 projected into the appropriate stratigraphic and geographical position to represent the geological conditions encountered at the site. An isopach map of the Rome in northeastern Ohio is presented as Figure 5-23.

From core data obtained at the Vickery site, the sandy unit present in the middle of the Rome contains higher porosity and permeability than do the lower and upper dolomite units. Considerable volumes of core data was provided with the initial Vickery petition submittal.

The Rome-Eau Claire is overlain by the Conasauga Formation, with a variable lithology across the state ranging from sandy dolomite to silty sandstone to red and green shales to limestone. Figure 5-24 is an Isopach map of the Conasauga in northeastern Ohio.

The Kerbel Formation is the fine to coarse grained dolomitic sandstone partially overlying and partially stratigraphically equivalent to the Eau Claire and Conasauga Formations, and underlying the Knox Dolomite across a large area of central Ohio. Figure 5-25 is an Isopach map of the Kerbel in northern Ohio.

The name Knox Dolomite is applied to the dolomite overlying the Eau Claire, Kerbel and Conasauga Formations, and underlying the regional Knox Dolomite unconformity. The

Knox Dolomite in Ohio consists of dolomite, sandstone and stratigraphically restricted limestone. The formation thickness is significantly affected by a regional unconformity which occurs at approximately the lower Ordovician -Middle Ordovician boundary (The Cambrian - Ordovician Systemic boundary occurs on top of the Knox Dolomite at the Vickery facility). Figure 5-26 is an Isopach map of the Knox in Ohio.

The Knox Dolomite is overlain by basal Middle Ordovician dolomites and clastics of the Wells Creek Formation. The Wells Creek often consists of green shale and siltstone, but may locally contain sandstone or argillaceous sandy dolomite.

The Black River Group is composed of argillaceous, micritic, burrowed limestones, micritic limestone with dolomite filled burrows in the middle third and interbedded micritic and pelletal limestone and fine grained dolomite. The upped one-third of the formation contains a series of relatively thin beds of bentonitic shale or argillaceous or bentonitic limestone.

The contact between the Black River and the overlying Trenton Limestone is usually picked at a prominent bentonite bed since the lithographic limestones of the upper Black River are not distinguishable from the medium to finely crystalline Trenton Limestone using geophysical logs. Sample examination is usually required for an exact correlation.

The name Cincinnatian Series, a time-stratigraphic term, is restricted to rocks of Late Ordovician age. Most of the "formations" assigned to the Cincinnatian Series are actually biostratigraphic zones. The series consists of thinly interbedded shales, limestones and siltstones. An erosional unconformity marks the upper boundary of the Cincinnatian Series and marks the approximate systemic boundary between the Ordovician and Silurian.

The Cataract Group, consisting of the Brassfield Formation (locally) (known as the Manitoulin Dolomite in this part of northern Ohio) and the Cabot Head Formation were deposited in ascending order above the unconformity. The Manitoulin Dolomite consists generally of dolomitized coarse grained limestone which grades upward into interbedded green and reddish-brown shale and dolomitized coarse grained limestone which makes up the Cabot Head Formation.

The Cataract Group is overlain by the Dayton Formation which is composed of two thin dolomitized limestones which may be locally separated by a green shale member. The Dayton is in turn overlain by the Rochester Formation which may be a green, gray, and dark brown shale or argillaceous dolomite.

The Lockport Group overlies the Rochester Formation. The Lockport, in ascending order, may be composed of crinoidal gray dolomite; a finely crystalline brown dolomite which may contain chert; and a coarsely crystalline vuggy gray and white dolomite.

The Lockport is in turn overlain by the evaporite sequence of the Salina Group. In the eastern portions of Ohio, the Salina may be differentiated into distinct lithologies more readily than in the central or western areas of the state.

The limestones, dolomites and evaporites which overlie the middle Silurian Rochester Shale, and underlie the Middle Devonian Ohio Shale are often collectively referred to as the Big Lime. The Big Lime is present across much of Ohio, and where it is at or near the surface along the Findlay Arch forms an important aquifer.

An erosional surface of Silurian sedimentary units form the bedrock surface beneath the Vickery site. To the east of the Vickery facility and down-dip structurally from the Findlay Arch, younger aged Paleozoic sedimentary units are present in the subsurface. These units are not present at the Vickery site, either due to non-deposition or post deposition erosion.

gentle east dip on the flank of the Findlay Arch. No significant odor or fluorescence was noted in samples when drilling the waste injection wells. No odor or fluorescence was noted within any unit of the injection interval, however a minor non-commercial hydrocarbon show was observed at the Knox unconformity during drilling of Well No. 1.

During the installation of the Knox-Kerbel Well in 1993, a standard oil field gas chromatograph was in operation monitoring the return drilling mud flow. The highest concentration of gases detected by this instrumentation was encountered between 262 and 280 feet md, near the top of the Lockport Formation within the Big Lime. A maximum of 720 Total Gas Units and 38,700 ppm methane was recorded. At deeper drilling depths, the gas content of the return mud stream rarely exceeded 20 Total Gas Units. At the top of the Trenton Formation, there was no increase in gas noted when this formation (which has historically been a producer of gas and oil in northwestern Ohio) was penetrated. There was also no mud gas increase noted when the Knox Dolomite or Kerbel Formation were penetrated. Due to the lack of significant hydrocarbon shows in the well, no drill stem tests were scheduled or performed. This failure to encounter any commercial hydrocarbon shows in the well collaborates the findings from the previous drilling of the injection wells at the site. Results of the monitoring during installation and an in depth study of the cores concluded that there was no evidence of commercial hydrocarbons.

A reflection seismic program was shot by Vickery within the AOR. A broad anticline feature exists beneath the facility in the Precambrian basement diminishing in amplitude upward through Ordovician age Trenton Formation units. This feature has the potential for the accumulation of hydrocarbons; however, commercial hydrocarbon accumulation has not been found. It appears that the likelihood for the existence of commercial hydrocarbons within the AOR is remote as supported by the previous paragraphs above.

Sand, gravel, limestone and gypsum are commonly quarried in portions of northern Ohio. No mines, quarries, sand or gravel pits are known to exist within the AOR. Figure 5-34 shows the location of sand and gravel quarries and limestone and dolomite quarries in and near Sandusky County. No quarrying operations are within the AOR.

5.5 GEOLOGY OF THE VICKERY SITE

5.5.1 Structure

The Geology of the Vickery site was extensively evaluated when the facility submitted its initial petition, and is summarized here. There has been no drilling activity within the AOR that has impacted the interpretation of the subsurface geology since the initial petition was prepared.

The Vickery site is located east of the crest of the Findlay Arch. Figure 5-35 is a sub-regional structure map on the top of the Trenton Limestone showing the location of the facility on east-southeast dip of approximately 40 ft per mile.

The stratigraphic column of the geology within the AOR was previously illustrated in Figure 5-2. A series of structure maps were constructed within the AOR using the relatively sparse subsurface control available. Figures 5-36 and 5-37, included here, are reductions of maps on top of the Cincinnatian and Mt. Simon Sandstone, respectively. They are representative of the structure within the AOR.

Figure 5-38 is an enlargement from Baranoski's 2002 interpretation mapping the Precambrian unconformity showing the structure in the vicinity of the Vickery facility. The locations of the reflection seismic lines that were shot by Vickery in 1989 as a portion of preparing the initial USEPA no-migration demonstration are shown on this map. Excerpts from the report compiled by Weston Geophysical from their analysis of the data are included below. Attachment I includes the results of the seismic study performed at the facility in 1989 and provides additional information on the geology of the facility.

> *Overall, the 59 miles of seismic reflection data, obtained within a 5 mile radius of the Vickery site, are consistent with the gently southeastward dipping Precambrian unconformable surface overlain by the relatively uniform, Early Paleozoic sedimentary units. Superimposed on the regional southeastward dipping surface,*

a low relief anticline trends north-south beneath the Vickery site. Time structure and isochron and depth converted structural contour and isopach maps of the Precambrian surface and the Mt. Simon, Rome and Trenton units, indicate localized sediment thinning and thickening, predominately within the Mt. Simon, due to nondeposition and/or erosion and filling over paleotopographic relief. Slight arching of the interpreted formations suggests minor intermittent uplift.

The primary feature of interest, revealed in examination of the seismic reflection profiles and delineated on the Precambrian structural contour map, is a broad north-south trending high superimposed on the regional southeastward dipping surface. The main component of the topographic high is approximately 2 miles wide and extends north-south at least 5 miles. However, the outline of the elevated surface is irregular, with subordinate lobes extending 2 miles to the northeast and 1.5 miles to the west of the main trend beneath the site the maximum relief on the feature is approximately 120 feet measures on the Precambrian surface.

The Mt. Simon unit (Mt. Simon Thickness map) locally thins and thickens corresponding to paleotopographical relief on the Precambrian surface (Precambrian Surface map). This effect is apparent over the principal structural high as well as several other less extensive flexures of both positive and negative relief. Sediment thickness variations are attributed to variable deposition and erosion events in a shallow marine transgressive environment over the irregular Precambrian surface.

The Mt. Simon Formation thins by approximately 60 feet, directly over the broad Precambrian paletopographic high beneath the site, indicating that a certain amount of relief was present prior to and during Mt. Simon deposition. However, it is evident that the total relief presently observed at this location on the Precambrian surface (Precambrian Structure map) could not have been present *during Mt. Simon deposition. A Precambrian erosional remnant of that magnitude (120 feetA0 would have remained exposed above seal level in the shallow intertidal marine environment indicated for initial plaeozoic deposits, presumably resulting in nondeposition, of the Mt. Simon sandstone.*

The next prominent reflection horizon above the Mt. Simon is the top of the Rome Formation, caused by the contrast of Upper Rome dolomite in contact with sandstone of the Conasauga Formation. The top of the Rome is the most consistent horizon of the four mapped in this study. The structural contour map of the Rome surface is consistent with other mapped horizons, showing a broad north-south trending anticline superimposed on the regional southeastward dip.

The interval between the top of the Rome and Trenton reveals no consistent reflection horizons. The youngest consistently usable marker horizon is the Trenton. Structural contour mapping of this formation (Trenton Structure) reveals a flexure over the principal structure high beneath the site, consistent with but of less amplitude than those detected below. The isopach map for the interval between the Trenton and the Rome formations shows no appreciable thinning over the structural high beneath the site indicating that the Precambrian paleotopographic relief did not significantly influence sediment deposition at this level.

The deformation associated with formation of the structural high beneath the site is a relatively minor response to regional tectonic movements influencing the Findlay Arch and adjacent basins. The absence of any abrupt discontinuities in the Paleozoic horizons or evidence for brittle deformation in the Precambrian basement, penetrating into overlying Paleozoic units, indicates that episodic formation of the broad feature occurred slowly in a nonbrittle manner perhaps over substantial lengths of geologic time.

No faulting has been detected in wells within the AOR through log correlations. The series of structure maps which were constructed generally showed east-southeast dip except where interrupted by the gentle structural nose near the facility.

The correlation of the wells within the AOR is relatively clear-cut and leaves little margin for subjective judgment. The waste disposal wells at the site are closely spaced and correlate with each other in a very consistent manner, leaving little possibility that faulting exists.

Figure 5-39 is a stratigraphic cross section utilizing actual electric logs at a vertical scale of 1" = 100 feet within the Vickery AOR. This cross section shows that excellent correlation of the units across the area. Figure 5-40 is a schematic structural cross section across the AOR showing that southeast dip component present in all maps of the area. Figure 5-40a is a stratigrahphic cross section showing the very good subsurface correlations between the Vickery site and a deep well in northwestern Seneca County, about 15 miles to the southwest of Vickery.

5.5.2 Stratigraphy

The stratigraphy at the Vickery site was derived from well logs and descriptions of drill cuttings and cores. Figure 5-1, previously presented, showed the stratigraphic column at Vickery and identified the injection and confining zones.

Over a period of almost 20 years Vickery has performed numerous studies on cores recovered from the site injection wells. Earlier studies focused mostly on lithology, porosity, permeability and compatibility of the formation materials with the injected wastes. Later studies concentrated more on evaluating the depositional environments and diagenesis of the formation through both megascopic and microscopic examinations in additional to physical properties. A comprehensive core study performed in 1989 (included in the Vickery petition as Appendix P) evaluated approximately 800 feet of core. This study indicates that there have been multiple episodes of cementation, dissolution, and diagenesis in all of the Precambrian through Knox cores evaluated. Minor fracturing was observed in the cores from the Mt. Simon, Rome, Conasauga, Kerbel and Knox Formations. No displacement was observed in the stabbed cores or in thin sections made in the fractures intervals. Most fractures were discontinuous due to cement fill. These were interpreted as natural fractures affected by post depositional diagenesis. Some fractures that did appear continuous were sharp clean break that showed no evidence of any cementation or dissolution. These open fractures were interpreted as having been induced by the coring operation and were not representative of the actual formation conditions.

Within the AOR, the Precambrian basement was reached at depths ranging from 2884 ft (-2266 ft) in Disposal Well No. 3 to 3092 (-2441 ft) in the East Ohio Gas company No. 1 Haff. Basement samples from the No. 1 Haff were described by McCormick (1961), who determined the Precambrian at that location to be medium grained granite composed of pink orthoclase and quartz, with accessory biotite and plagioclase.

Within the Vickery facility, the basement encountered in Disposal Well No. 1 is described megascopically as dark reddish brown, fine to medium grained, equigranular rock composed of potassium feldspar, plagioclase, quartz and biotite with a well defined foliation produced by sub-parallel orientation of biotite flakes. Microscopic examination of thin sectioned material indicated a composition of quartz 31.9%, microcline 34.1%, plagioclase 27.4%, biotite 4.8%, perthite 1.3% and accessory minerals 0.5%.

Cuttings samples from Disposal Wells No. 2, No. 3 and No. 4 at the site were described as light orange to red granite with biotite, by the well site geologist. Granite and gneiss are compositionally similar, and it is possible that foliation was present in the samples but not observable due to the small size of the cuttings. A thin section taken from 2926.7 ft measured depth in Disposal Well No. 1 was described as a massive, alkali granite. Crystal size ranged from .09 to 1.9 mm, averaging .53 mm. The subequant to elongate crystals consisted of 38% quartz, 31.6% K-feldspar, 26% plagioclase, 2.4% biotite, 1.6% hornblende, .4% other minerals. Microfractures were partially filled by chloritic clay minerals. No metamorphic minerals or textures were observed.

The Vickery facility is located within the transition zone between the Grenville and East Granite-Rhyolite Province provinces as plotted by Lucius (1988), and variable lithologies are to be expected within this zone.

During February, 1990, Vickery performed additional petrographic studies on cutting samples from Disposal Wells Nos. 2 and 3, which were on file with the ODNR. The purpose of the work was to determine the depth at which the Precambrian basement was penetrated. The study indicated that in Well No. 3, Precambrian granite was encountered at a measured depth between 2890 and 2900 ft. From geophysical logs, the top was previously picket at 2884 ft measured depth (-2266). The Precambrian positive structure feature beneath the No. 3 well is therefore confirmed by the cutting petrography.

In Well No. 2, no Precambrian igneous lithology was noted in the cutting petrographic study. Previous cuttings descriptions placed the Precambrian at 2930 ft measured depth (-2314). This depth (2930) did not agree with geophysical logs run in the No. 2 well and was not utilized in structural mapping for the site. Instead, a Precambrian top of 2950+ ft measured depth (-2334+) from geophysical logs was used for mapping purposes. This places the Precambrian very near the bottom of the well. The petrographic study indicates that even this top is structurally to high. It is believed that the Precambrian must be quite close to the bottom of the No. 2 well, based on the close proximity of a good control point in the No. 1A well.

In 1993, the Knox-Kerbel monitor well was installed approximately 90 feet northeast of the No. 2 injection well. Prior to drilling, it was anticipated that the monitor well would encounter geological formations in a structural position and with thickness very similar to that found in the No. 2 injection well. This pre-drilling concept proved to be correct, and there was an excellent correlation between the two wells. Table 5-3 presents the structural and stratigraphic relationship of the monitor well compared to the No. 2 injection well. The Knox-Kerbel monitor well actually ran about 1.5 to 6.5 feet low structurally relative to mean seal level datum versus the No. 2 injection well. At shallower depths, the monitor well was slightly thin to the No. 2 well, but all comparable formation thicknesses varied by not more than 2 feet.

In Seneca County, approximately 15 miles southwest of the site and 10 miles outside the AOR, the Ohio Division of Geological Survey continuously cored the No. 1 M. and B. Asphalt Company well from the upper surface of bedrock into the Precambrian. At this location, the Precambrian was a dark green to black gabbro with fractures filled with dark red and medium green materials of undermined mineralogy (Wickstrom et.al., 1985). This well was drilled near the center of one of the largest gravity and magnetic anomalies in Ohio, an area from which amphibolite has also been reported from the basement (Lucius, 1988), and falls within the transition zone between the Grenville and East Granite-Rhyolite Province.

The injection interval, the Mt. Simon Sandstone, unconformably overlies the Precambrian basement. The Mt. Simon Sandstone ranges from 147 ft to 84 ft in thickness for wells within the AOR, and has an average thickness of about 122 ft. Variation in thickness is largely controlled by relief on the Precambrian surface. Figure 5-41 is an isopach (isochore) map of the thickness of the Mt. Simon. This map is based solely on well control, and shows all dashed contour lines due to the uncertainty of the formation thickness away from the control points. Thickness represented on this map inside the AOR ranges from slightly leass than 100 feet to just over 150 feet. Figure 5-42 is an Isopach map drawn by Weston Geophysical using the 59 miles of seismic data shot by

Vickery in the AOR. This map generally indicates a Mt. Simon thickness from just under 100 feet to just over 100 feet, except to the west of the facility one to three miles where the thickness is shown to reach as much as 200 feet.

The Mt. Simon Sandstone is composed of moderately to well sorted, very fine to coarse grained sandstone. These sands contain low quantities of detrital clay, but authigenic grain-coating chlorite is fairly common. Dolomite cement and interbedded dolomites are sporadically distributed through the sandstones. Additional information on mineralogy, texture and lithology are provided in Attachment C.

The containment interval at Vickery consists of the Rome, Conasauga, Kerbel Formations and Knox Dolomite. This interval consists of approximately 440 ft of dolomites and sandstones and acts as a barrier to waste movement out of the Mt. Simon Sandstone (injection interval). The thickness, lithology, texture and depositional environment of each formation is discussed in Attachment D.

The confining zone is composed of the Wells Creek and Black River Formations. These formations consist of limestones and shales approximately 545 ft in total thickness. Information about these formations is provided in Attachment E.

5.5.3 Base of Lowermost USDW

The lowermost USDW beneath the Vickery site is the Lockport Formation. While log calculations indicated the Manitoulin Dolomite(Brassfield) had TDS in excess of 10,000 ppm equivalent NaCl and the Lockport Dolomite has TDS concentrations less than 3000 ppm equivalent NaCl, during the installation of the lowermost USDW monitoring well at the site, the Manitoulin Dolomite did not produce sufficient quantities of fluid. Therefore, the Lockport Formation was selected as the location of the monitored interval for the subsequently drilled Lockport monitoring well, and the Lockport base at 574 feet measured depth is considered as the base of the USDW.

In the Vickery area of Sandusky County, the Lockport Dolomite is considered as a formation rather than a "group", due to the inability to differentiate it into the stratigraphic units identifiable in some other portions of Ohio. The Lockport and the undifferentiated Salina Group comprise what is known by the drillers term "Big Lime" in this area. The Big Lime is a major source of ground water in Sandusky County, especially for livestock and agricultural purposes. The existing ground water contains high amounts of sulfate materials primarily derived from gypsum and anhydrite units within the Salina Group. This high dissolved mineral content renders much of the ground unusable for human drinking purposes.

Vickery has an active groundwater monitoring program which involves monitoring of the Knox-Kerbel Formations, and the Lockport Formation. Figure 5-43 shows the distance of the wells from Well No. 2. The monitoring program for the Knox-Kerbel includes continuous monitoring of the reservoir pressure within the lower Knox Dolomite and upper Kerbel Formation and annual sampling of the interstitial fluids from the Knox-Kerbel zone. The Lockport Monitor well is sampled on an annual basis. This program has been ongoing since 1993 and has confirmed that the waste is not migrating out of the injection zone and that pressurization of the subsurface formations is consistent with that predicted by the SWIFT model prepared for the no-migration petition. The modeling simulation, utilizing conservative petrophysical and well operating parameters as input, predicted as much as a 60 psi increase in the Knox-Kerbel interval. The monitored formation pressure in the Knox-Kerbel interval has remained within these conservative control limits, indicating no excess pressurization due to injection activities. Twenty-five years of monitoring the formation fluid chemistry from the Knox-Kerbel has demonstrated relatively little change in the composition of the fluid. Detailed reports which include the results of the Knox-Kerbel and Lockport monitoring program have been submitted to the Ohio EPA periodically, as required.

Table 5-4 shows the most recent chemical sampling data from the Lockport well from April 2017. DWFF1, DWFF1D, and DWFF1B are the samples, supplicates and a field blank, respectively. Table 5-5 shows the chemical results for the sample from 1993-2017, indicating relatively little change with time.

Table 5-6 shows the most recent chemical sampling data from the Knox-Kerbel well, April 2017. Sample KKFF1, KKFF1R and KKFF1B are the sample, replicate and a field blank, respectively. Table 5-7 shows the chemical results for the Knox-Kerbel well from 1993-2017, indicating relatively little change with time. The baseline period for chemistry data from the Knox-Kerbel well was the initial eight (8) quarterly sampling events, after which the well was switched to an annual sampling schedule.

Figure 5-44 shows the pressure data from the Knox-Kerbel monitor well from April 2012 through April 2017 and corresponding injection pressure in injection Well No. 2. The step like appearance of the data is due to changes in measure specific gravity, which is utilized in calculating the formation pressure at the reference depth, with the steps occurring at the sampling events. There has been no increase in monitored formation pressure due to injection activities at the Vickery site. The baseline period for pressure measurements was the five (5) quarters of pressure data measured from January 18, 1994 through April 10, 1995, excluding the first fifteen days of data immediately following a sampling event to allow for formation pressure recovery. The first two (2) quarters of monitored pressure data (July 9, 1993 through January 17, 1994) were excluded from the baseline data due to significant variations in measured specific gravity for the formation fluid.

10.0 CHARACTERISTICS OF THE INJECTION ZONE

10.1 Introduction

The criteria for siting of hazardous waste injection wells codified in 40 CFR, Part 146.62 (C)(1), requires that the injection zone has sufficient permeability, porosity, thickness and areal extent to prevent migration of fluids into USDWs.

The injection zone is defined in 40 CFR, Part 146.3 as a geological formation, group of formations, or part of a formation receiving fluids through a well. The injection of hazardous waste can only take place below the lowermost formation containing within 1/4 mile of the well bore, a USDW. Vickery has separated the injection zone into an injection interval, into which actual emplacement of waste fluid occurs, and a containment interval which includes the layers above the injection interval where vertical fluid movement will be contained.

The following subsections describe the injection intervals suitability for injection of hazardous waste and the containment intervals properties which make it capable of limiting fluid movement out of the injection zone.

10.2 Injection Interval

10.2.1 Lithology, Reservoir Thickness

The permitted injection interval for the Vickery waste disposal wells is the Mt. Simon Formation, a Cambrian age sandstone. The Mt. Simon averages slightly over 121 feet in thickness, with minimum and maximum recorded thickness of 84 and 147 feet respectively from wells within the AOR. The formation is composed of moderately to well sorted, very fine to coarse grained sandstones. Quartz and K-feldspar are the primary framework grains. These sandstones contain low quantities of detrital clay, but authigenic grain coating chlorite is fairly common. Dolomite cement and interbedded dolomite zones are sporadically distributed throughout the formation. Detailed data concerning lithology of the injection interval is found in Attachment C.

10.2.2 Porosity and Permeability

Porosity is a measurement of how much void space is available for fluids to occupy within a volume of rock, generally expressed as a percentage. Permeability is a measurement of the capacity of a material to transmit a fluid under the influence of a pressure differential. A standard unit of permeability measurement is the darcy, which

TABLE 10-1

MT. SIMON POROSITY AND PERMEABILITY TO AIR

		Total Mt. Simon Thickness	Top 30 Feet
WELL #1*	N	89	21*
	K_h(md)	36.09	24.26
	ϕ_h(%)	15.06	14.53
	N	89	21*
	K_v(md)	.0086	.29
	ϕ_v(%)	NA	NA
WELL #4	N	93	30
	K_h(md)	62.08	98.06
	ϕ_h(%)	12.65	14.97
WELL #5	N	132	30
	K_h(md)	32.01	60.98
	ϕ_h(%)	13.63	13.60
3 WELLS OVERAGED	N	314	81
	K_h(md)	42.07	65.19
	ϕ_h(%)	13.75	14.35
	N**	89	21*
	K_v(md)	.0086	.29
	ϕ_v(%)	NA	NA

* Upper 9 ft of Mt. Simon was not cored
** Only from #1 Well
N Number of samples
K_h Arithmetic mean
K_v Harmonic mean
ϕ_h Arithmetic mean

is defined as the flow of one cubic centimeter per second of a fluid with viscosity of one centipoise through a porous medium having a cross sectional area of one square centimeter and length one centimeter, under a pressure differential of one atmosphere. As a practical matter, measurements are usually expressed in millidarcies (md), where one millidarcy = .001 darcy.

There have been many different studies performed on the Vickery wells over a period of more that 20 years. The following is a summary of porosity and permeability data. The reader is referred to the original petition document, and to Appendix A of this document which specifically summarizes flow through testing and petrographic tests that were completed after the original petition was submitted. The full report of these tests were previously submitted to the USEPA and ODNR.

Porosity and permeability of the Mt. Simon at Vickery were obtained through plug and whole core analysis of cores from Disposal Wells Nos. 1, 4 and 5. The arithmetic mean horizontal permeability to air in the 3 cored wells was 42.1 md (314 samples), and ranged from <.0001 md to 730 md. One sample in the No. 5 well tested for horizontal permeability at 50 md in one direction and 3037 md at 90 degrees to that direction. This extremely high value is believed to have been caused by induced fracturing of the sample, and is not reliable. The harmonic mean vertical permeability to air as measured in the No. 1 well was .0086 md, and ranged from <.0001 md to 163 md, (89 samples). Porosity in the three cored wells averaged 13.75 percent, and ranged from 2.9 to 22.8 percent, (314 samples).

Within the top 30 feet of the Mt. Simon in the three cored wells, horizontal permeability to air averaged 65.2 md and ranged from <.1 md to 730 md. Porosity averaged 14.4 percent and ranged from 2.9 to 22.8 percent. The significance of this above average permeability and porosity will be explored in greater detail later in this section, and in the modeling section. Table 10-1 summarizes the porosity and permeability to air data for the Mt. Simon.

Figure 10-1 represents the horizontal permeabilities from Disposal Wells Nos. 1, 4 and 5 as measured in cores at one foot intervals, and demonstrates the lateral continuity of the permeability zones across the Vickery site.

Figures 10-2, 10-3 and 10-4 compare core measured permeabilities to the bulk density logs through the corresponding intervals. There is a good to fair correlation of the

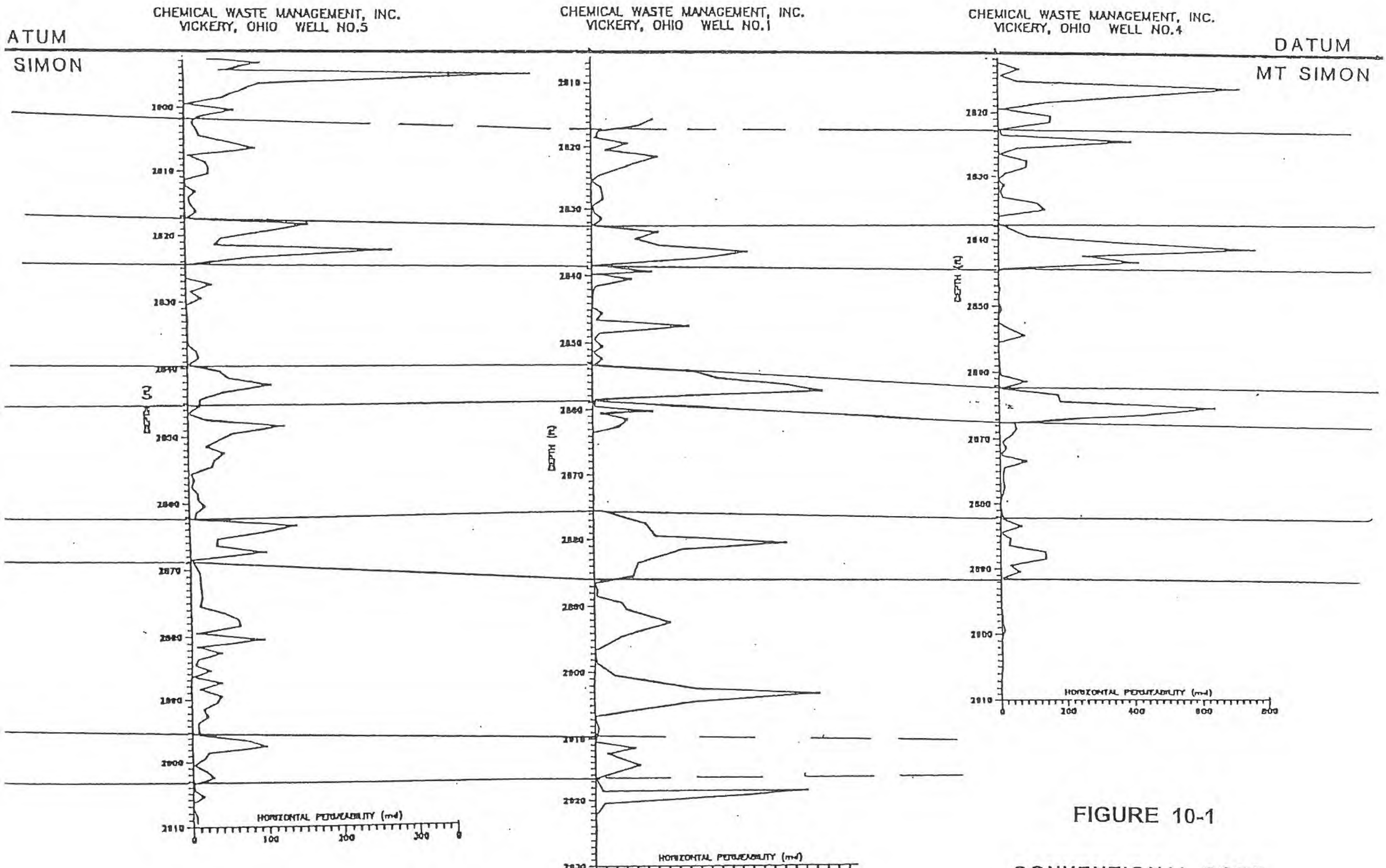
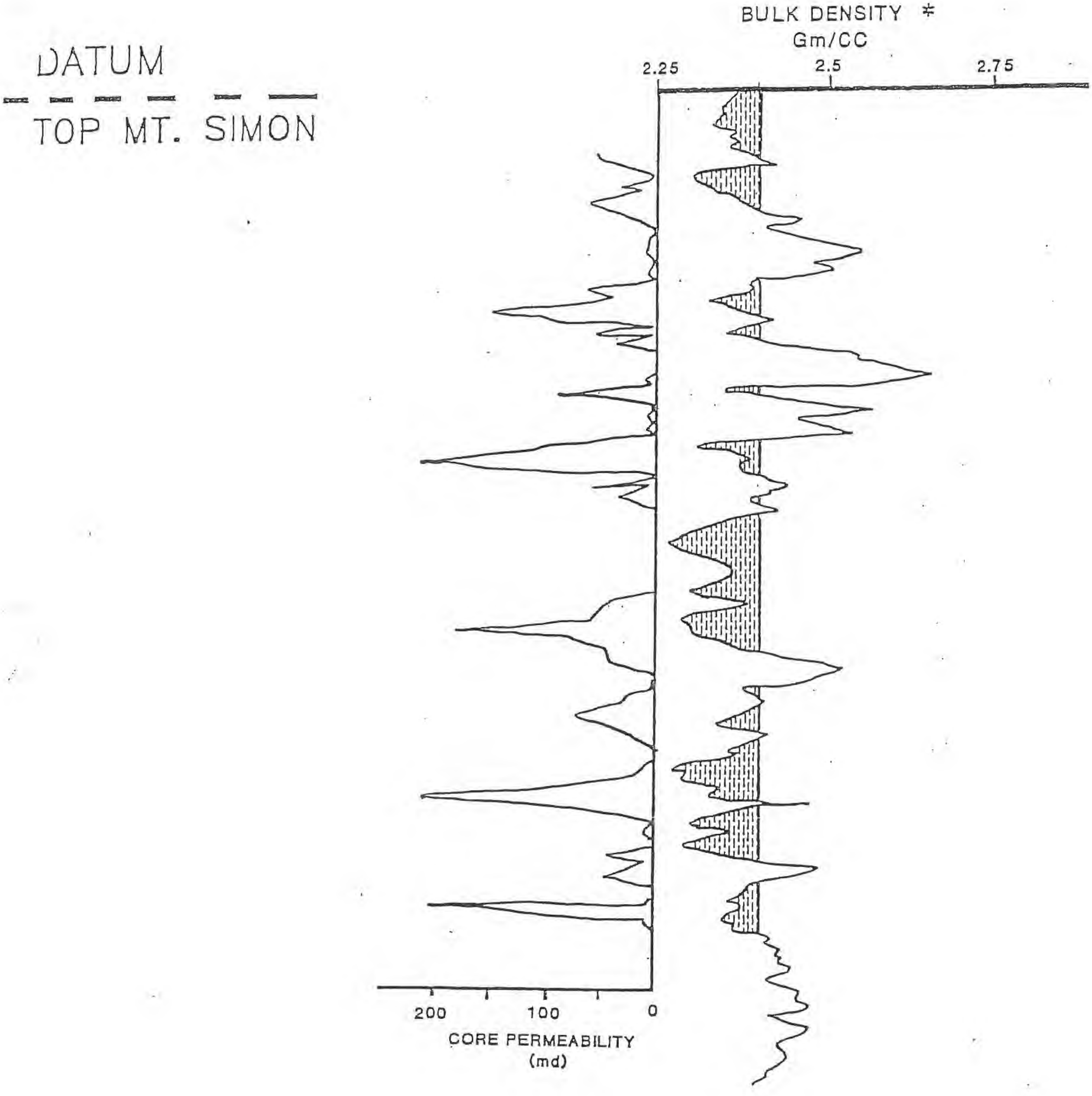


FIGURE 10-1

CONVENTIONAL CORE

PERMEABILTY CORRELATION



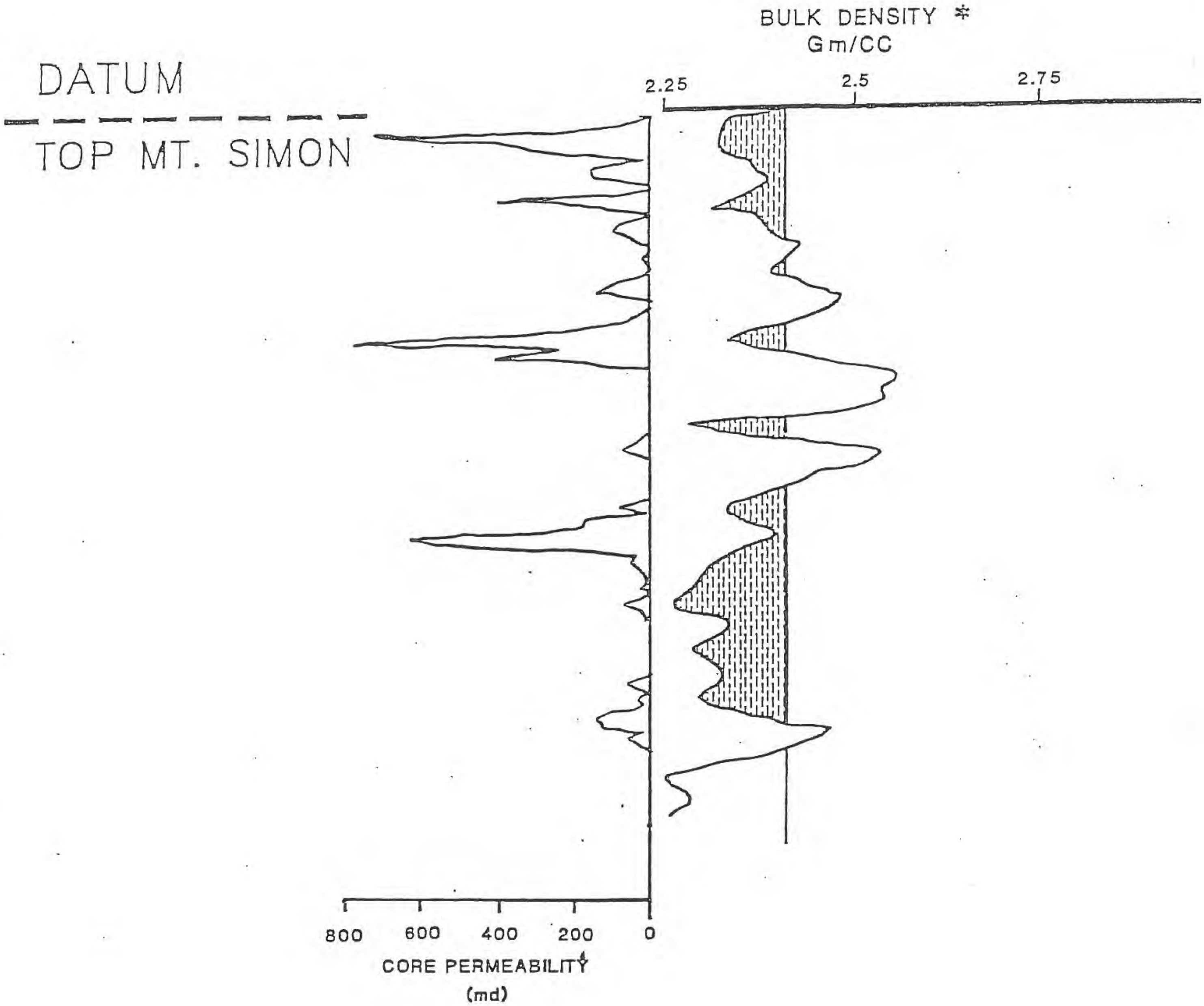
20'

ZONES WITH POROSITY > 15%, ASSUMING MATRIX DENSITY = 2.68 GM/CC.

* FROM SCHLUMBERGER COMPENSATED FORMATION DENSITY LOG RUN 3/17/72.

DISPOSAL WELL NO. 1
CORE PERMEABILITY VS.
BULK DENSITY

FIGURE 10-2



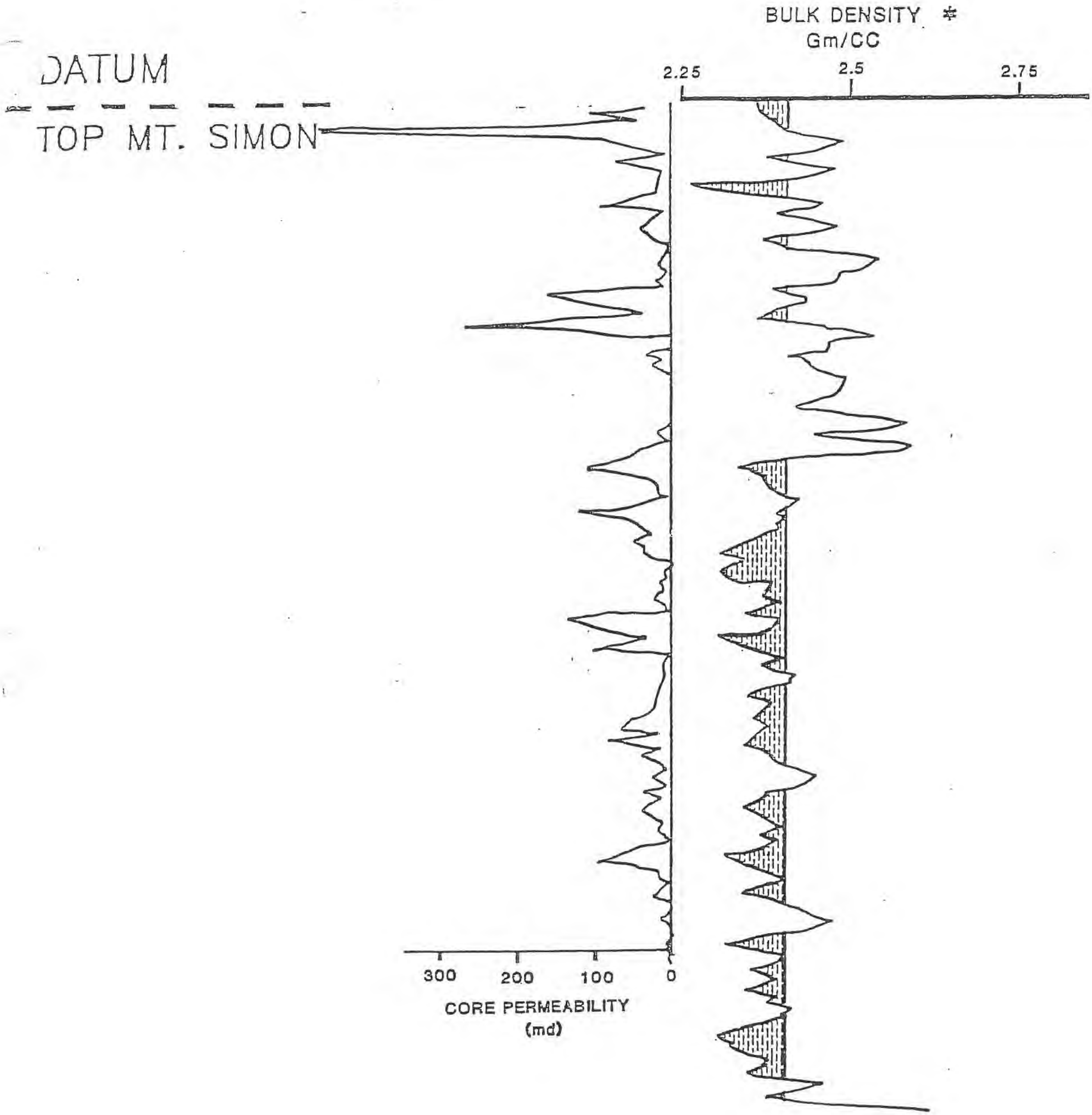
20'

ZONES WITH POROSITY > 15%, ASSUMING MATRIX DENSITY = 2.68 GM/CC.

* FROM BIRDWELL DENSITY BOREHOLE COMPENSATED LOG RUN 7/29/76.

DISPOSAL WELL NO. 4
CORE PERMEABILITY VS
BULK DENSITY

FIGURE 10-3



20'

ZONES WITH POROSITY > 15%, ASSUMING MATRIX DENSITY = 2.68 GM/CC.

* FROM SCHLUMBERGER COMPENSATED NEUTRON-FORMATION DENSITY LOG RUN 11/15/80.

DISPOSAL WELL NO. 5
CORE PERMEABILITY VS.
BULK DENSITY

FIGURE 10-4

porosity zones represented on the density logs with the permeabilities obtained from core measurements.

The effect of relatively low relief Precambrian topography on the containment capabilities of the injection zone is expected to be negligible. It will be demonstrated later in this section that most of the injected waste goes into the uppermost portions of the Mt. Simon. These zones are continuous across the Vickery site and are not affected by Precambrian topographic relief.

Porosity vs permeability (>.1 md) cross plots for Disposal Wells Nos. 1, 4 and 5 are shown in Figures 10-6, 10-7 and 10-8. Combined data from all three wells are represented in Figure 10-9. There is generally fair correlation between porosity and permeability within the Mt. Simon. Data scatter is thought to be largely due to the presence of variable amounts of quartz and dolomite cement, and argillaceous materials.

10.2.2.1 Porosity Development and Diagenesis

The Mt. Simon consists largely of sandstones with high textural variability and dolomite beds which appear to have formed by diagenetic replacement. Sandstones with the highest porosity development are generally well sorted, clay-poor, fine to medium grained sand that are relatively free of pore filling dolomite cement.

The diagenetic alteration of these sandstones began with moderate burial compaction which was then succeeded by the formation of grain-coating chlorite, quartz overgrowth cements (followed closely by K-feldspar overgrowth cement), and followed in turn by the

FIGURE 10-6

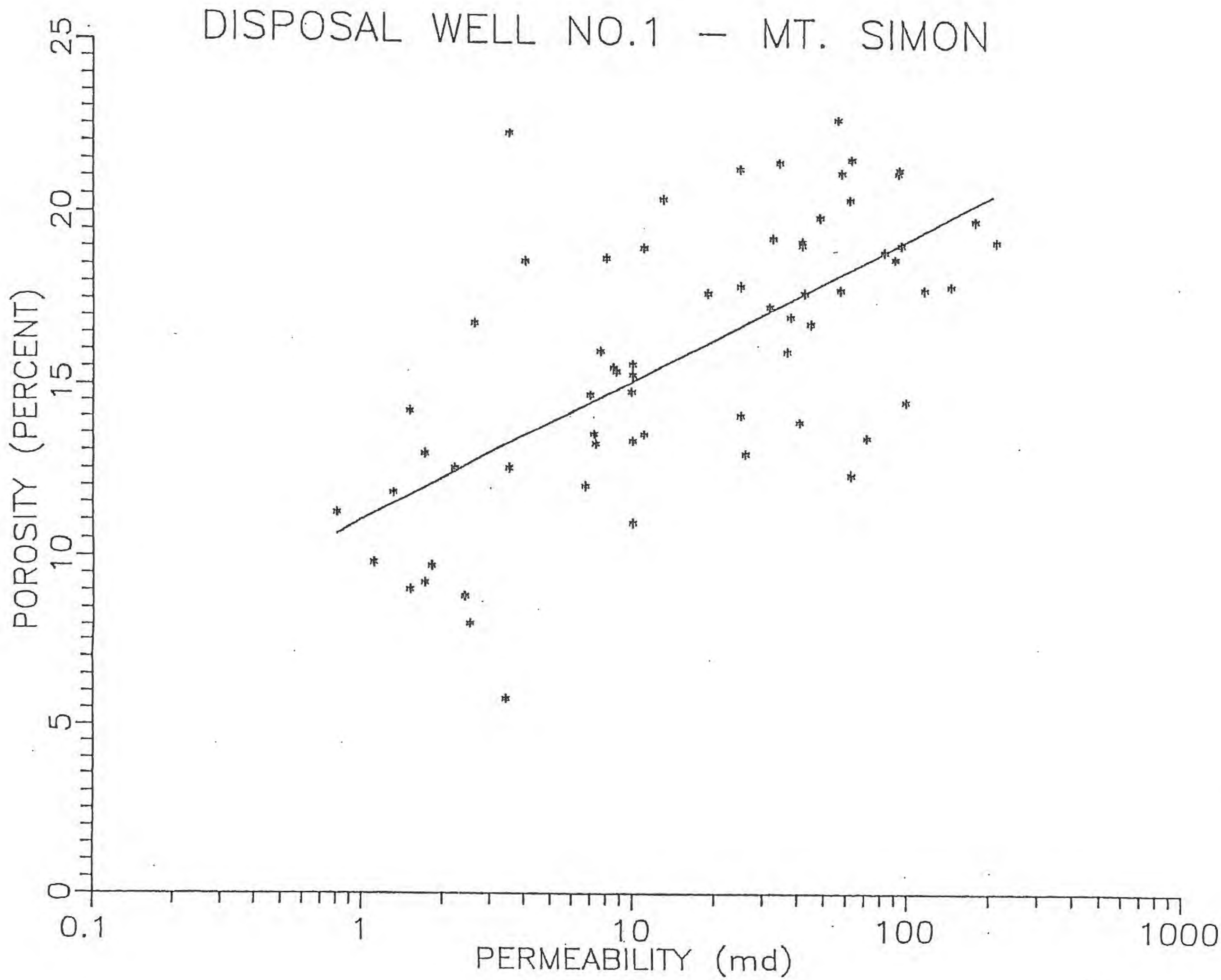

DISPOSAL WELL NO.1 — MT. SIMON
POROSITY (PERCENT)
0
5
10
15
20
25
0.1
1
10
100
1000
PERMEABILITY (md)

FIGURE 10-7

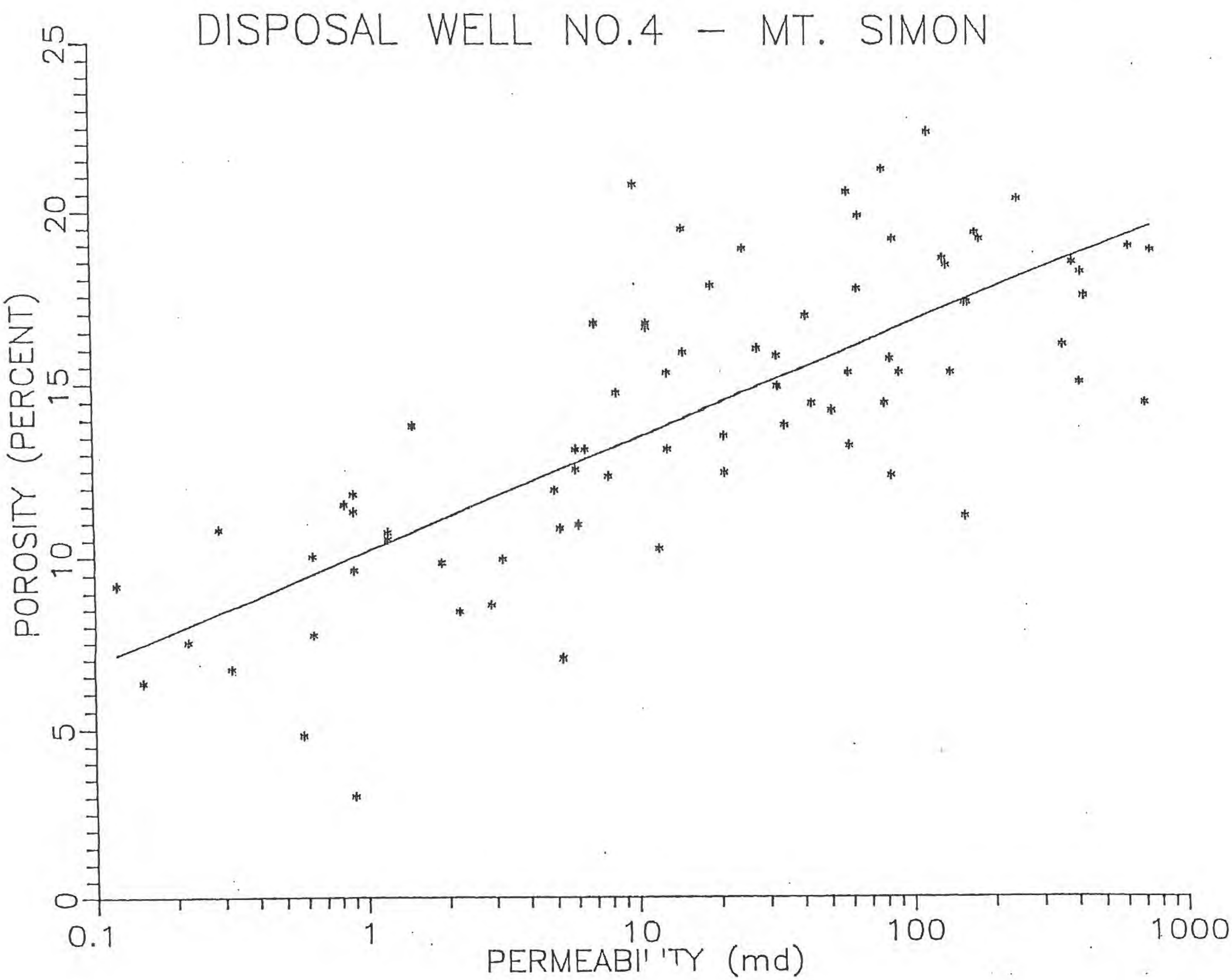

DISPOSAL WELL NO.4 — MT. SIMON
POROSITY (PERCENT)
0
5
10
15
20
25
0.1
1
10
100
1000
PERMEABI' 'TY (md)

FIGURE 10-8

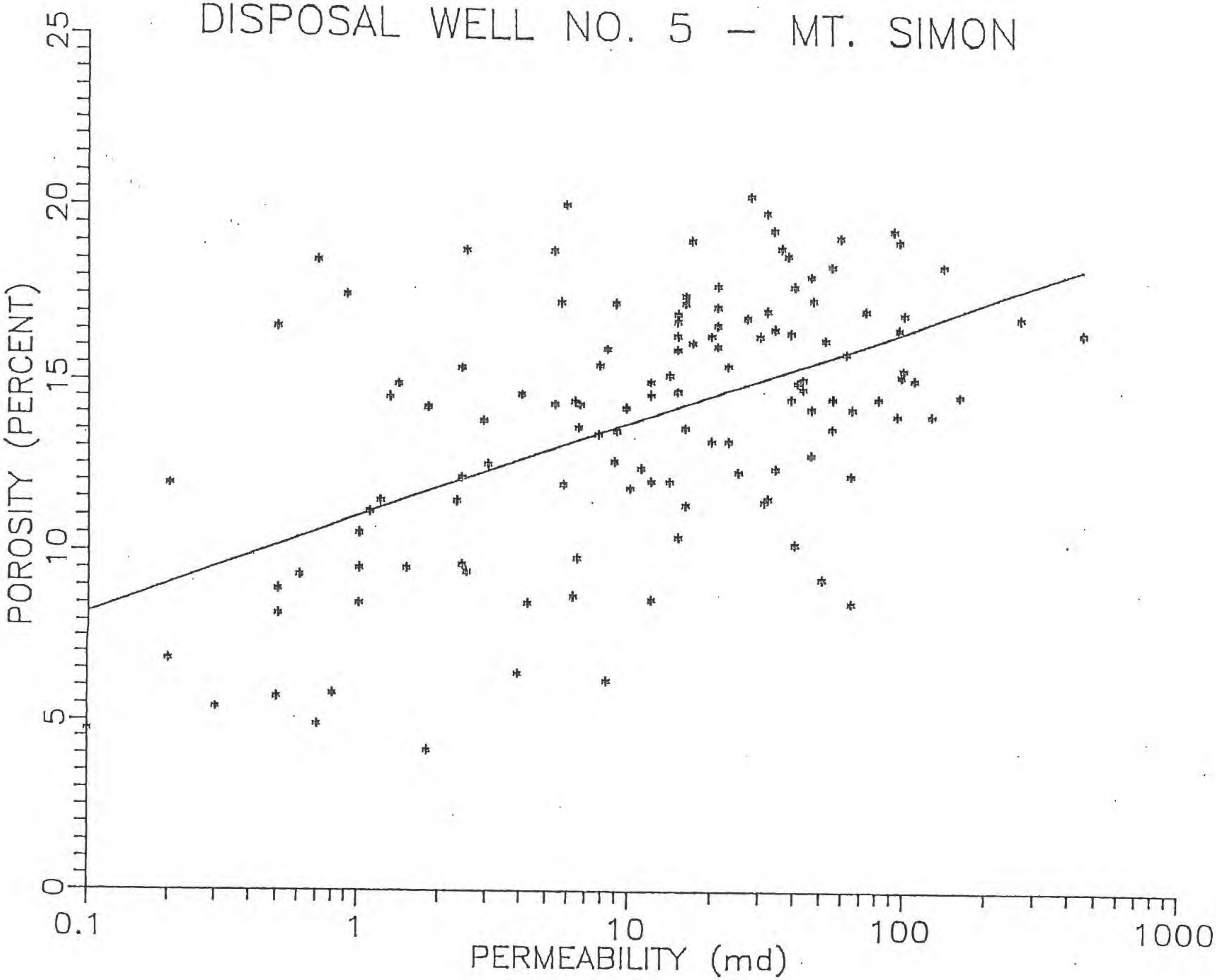
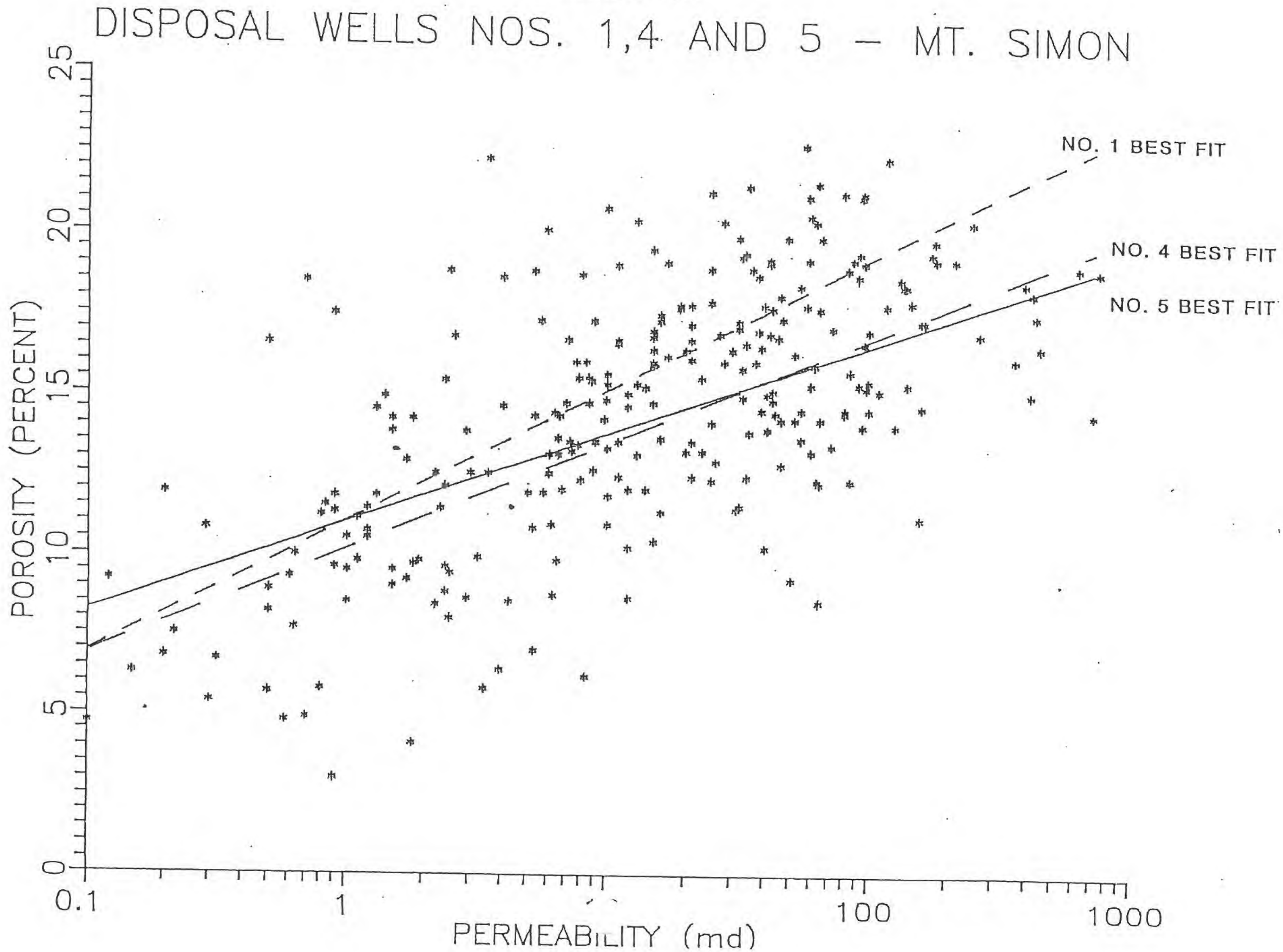

DISPOSAL WELL NO. 5 – MT. SIMON
POROSITY (PERCENT)
0
5
10
15
20
25
0.1
1
10
100
1000
PERMEABILITY (md)

FIGURE 10-9


DISPOSAL WELLS NOS. 1,4 AND 5 - MT. SIMON
NO. 1 BEST FIT
NO. 4 BEST FIT
NO. 5 BEST FIT
POROSITY (PERCENT)
0
5
10
15
20
25
0.1
1
100
1000
PERMEABILITY (md)

dissolution of unstable detrital grains (largely feldspar). Dissolution porosity was followed by a second phase of quartz cementation, the development of authigenic illite (which occurs in small amounts), and rare pyrite cement. An earlier, sometimes extensive episode of dolomite cementation, was recognized in some beds, especially beds rich in carbonate particles (i.e. ooids, peloids). This episode appears to have occurred shortly after the development of K-feldspar overgrowth and immediately preceding secondary grain dissolution. This is suggested by the fact that dolomite cement often appears in thin section to envelope quartz and feldspar overgrowth, yet dolomite cement is almost never found within secondary dissolution pores. This phase of cementation reduces visible porosity to very low levels within some beds.

Visible porosity in thin section samples of the Mt. Simon ranges from 0.5 - 23.0%. In general, dolomite cemented sandstones display visible porosity of less than 8%, whereas clean, well sorted fine to medium-grained sandstones display much higher visible porosity (10%). In these cleaner sandstones, intergranular pores are evenly distributed, and secondary pores (moldic and intragranular pores) are present in high proportions. Measured permeability values typically exceed 50 md in such sandstones. Some sandstone beds within the Mt. Simon (especially the lower one-third of the interval) contain discontinuous clay-rich laminations. Although such sandstones contain moderate visible porosity (5-12%) the distribution of pores is often uneven. Measured permeability is often less than 5 md.

Although the Mt. Simon is variable in terms of texture and cement distribution, clean, well sorted sandstones with moderately high permeability characterize most of the Mt Simon sandstone.

10.2.2.2 Radioactive Tracer Profiles

In Section 10.2.2 of this document it was noted that the upper 30 feet of the Mt. Simon contains porosity and permeability which are above average for the formation. It appears that this upper portion of the formation accepts the bulk of the injected fluid.

Radioactive tracer profile surveys, utilizing Iodine 131 as a source, were previously run in each of the active disposal wells. Interpretation of the surveys has indicated that from 68 percent to over 90 percent of the injected fluid enters the Mt. Simon within the upper 30 feet of the formation.

10.2.3 Formation Fracture Gradient

The "strength" of a rock is a term used in experimental structural geology that is only meaningful when the environmental conditions the rock is subjected to are specified. In general, the strength of a rock is its ability to withstand differential stress to the point at which it undergoes brittle failure. The environmental factors affecting a rock's strength include, but are not limited to, mineralogy, grain size, porosity, confining pressure, pore fluid pressure, temperature, presence of reacting solutions and duration of stress. The combined influence of these factors control the point at which a rock will undergo brittle failure. Certain rock types may behave differently under differing sets of environmental conditions. The strength of a rock can be measured under varied environmental conditions via laboratory methods.

When hydraulically fracturing a well, an array of physical events are interacting within the well/formation system. The fluid is moving down the wellbore with momentum influenced by pump horsepower, rate, fluid density, fluid viscosity, wellbore mechanics, and pipe friction. The resultant hydraulic force impacts the formation with applied stress of sufficient magnitude to cause the rock to fracture. A fracture occurs in the formation when hydraulic pressure overcomes the combined resistances of the tensile strength of the formation and the compressional stress caused by the overburden stress gradient.

The surface pressure observed at the moment the pumping operations are suddenly discontinued is called the instantaneous shut-in pressure, ISIP. This represents the minimum pressure required to open a hydraulically created fracture. The ISIP may be related to an equivalent bottomhole pressure, the bottomhole treating pressure, by using the following equation:

BHTP = ISIP + Ph where

BHTP	=	Bottomhole Treating Pressure (psi)
ISIP	=	Instantaneous Shut-in Pressure (psi)
Ph	=	Hydrostatic Pressure (psi).

Once the Bottomhole Treating Pressure is known, then the fracture gradient can be determined from the following equation:

Fracture Gradient = BHTP / Depth.

A proposed fracture stimulation was attempted on the Vickery Well No. 5 on October 13, 1982. The fracture stimulation ended when the well "screened out"; that is, the wellhead pressure during the treatment reached the maximum allowable pressure (determined from the strength of the tubulars in the well) before the wellbore could be flushed of the sand ladened fluid. With the wellbore filled with sand ladened fluid, an instantaneous shut-in pressure representative of the minimum pressure required to open the fracture cannot be obtained because the fracture has already closed. Therefore it follows that under these conditions the fracture gradient cannot be obtained.

The fact that a representative ISIP cannot be obtained is substantiated by the field data on Well No. 5. The data shows that the field service operator did not record ISIP in any of three places where ISIP is normally recorded on the field record. The events that occurred can be determined from the field strip chart and will be discussed chronologically. The fracing procedure was progressing normally until 10:42 AM with Dowell pumping sand laden fluid with 7 lb/gal sand at a rate of 15 bpm at 1900 psi. Then at 10:44 AM the sand was increased from 7 lb/gal to 9 lb/gal. Immediately, pressure started building and by 10:48 AM pressure was at 3300 psi. This indicated screen out and fracture closure. The pumps were shut down for a minute while pressure fell to 1125 psi and then to 650 psi. A brief attempt to flush out the sand by pumping the pumps resulted in another 3300 psi pressure peak at 10:48 AM which again indicated screen out and fracture closure. Dowell then ceased operations and rigged down. All test data was submitted to the OEPA in the Well 5 Completion Report.

In January, 1984, Well No. 4 was notched from 2904 to 2896 ft using a Hydrajet tool. After the notches were made a radioactive tracer was released at 1900 ft (inside the 5 inch casing) and pumped down the well. The radioactive tracer log indicated that most of the fluid was entering the notched portion of the wellbore. Next a pump test was performed to establish the breakdown pressure and fracture gradient. The pump test never clearly indicated a breakdown pressure; therefore, Halliburton's engineers felt the test was inconclusive as to whether or not a fracture had been initiated. A final instantaneous shut-in pressure of 970 psi was recorded during the pump test. The BHTP can be determined from the instantaneous shut-in pressure as follows:

$$BHTP = ISIP + Ph$$

In this case Ph is equal to the hydrostatic pressure of a 2819 ft column (depth below ground to casing seat) of 10 lb/gal brine (type of fluid in the wellbore when shut-in), which is 1464.5 psi. Therefore, the BHTP = 970 + 1464.5 = 2432.5 psi which is equivalent to a fracture gradient of 0.86 psi/ft (2434.5 psi/2819 ft).

Following the pump test it was decided to Hydrajet the entire open-hole interval and not to fracture stimulate the well. All test data was submitted to the OEPA in the Well 4 Completion Report.

In June, 1984, Well No. 2 was notched from 2930 to 2920 ft using a Hydrajet tool. Next a pump test was performed to establish the breakdown pressure and fracture gradient. The pump test never clearly indicated a breakdown pressure; therefore, Halliburton's engineers felt the test was inconclusive as to whether or not a fracture had been initiated. Instantaneous shut-in pressures of 730 to 740 psi were recorded during the pump test. Based on these pressures, a 10 lb/gal displacement fluid, and a casing depth of 2791 ft., BHTPs of 2180 psi and 2190 psi can be calculated using the method described earlier. Those values give a frac gradient of 0.781 and 0.785 psi/ft. Following the pump test Well No. 2 was fracture stimulated. At the end of the fracture treatment an ISIP of 830 psi was recorded. Previously it was thought that the displacement fluid was 2% potassium chloride. However, upon closer examination of the well records it was determined that the 2% potassium chloride solution was followed by a 10 lb/gal sodium chloride brine prior to shutting down the pumps. The hydrostatic head of the 10 lb/gal brine is calculated as follows:

Ph = 1.2 spec. gravity x 0.433 psi/ft x 2791 ft. = 1450 psi.

Using observed ISIP of 830 psi and Ph of 1450 psi yields:

BHTP = ISIP + Ph = 830 + 1450 = 2280 psi

which is a 0.82 psi/ft fracture gradient. All test data was submitted to the OEPA in the Well 2 Completion Report.

In August 1984, Well No. 6 was notched from 2890 to 2880 ft using a Hydrajet tool. Next a pump test was performed to establish the breakdown pressure and fracture gradient. The pump test indicated the breakdown pressure was approximately 1600 psi. An instantaneous shut-in pressure of 990 psi was recorded at the end of the pump test. Based on this pressure, a 9.9 lb/gal displace-ment fluid, and a casing depth of 2809 ft, BHTP of 2345 psi and a frac gradient of 0.83 can be calculated.

During the same test, the initial breakdown pressure was calculated to be 3069 psi at 2880 ft or 1.07 psi/ft using the 1600 psi surface pressure recorded. All test data was submitted to OEPA, April 4, 1985 in the Well No. 6 Completion Report.

In August, 1994, Vickery performed additional evaluations on the formation fracture gradients. A report dated August 4, 1994 was submitted to Ohio EPA entitled "Fracture Gradient Project." This report concludes that data demonstrates that the current maximum surface injection pressure of 785 psig *(at that time)*, which is based on a fracture gradient of 0.75 psi/ft, will not initiate new fractures or propagate existing fractures in the injection zone.

10.2.3.1 Uncertainty in Determination of Fracture Gradients

Uncertainty in the determination of fracture gradients can come from two sources ISIP, and Ph, as determined by the following equation:

$$BHTP = ISIP + Ph$$

This discussion will quantify the expected uncertainty in the determination of BHTP and therefore fracture gradients.

Hydrostatic head, Ph is calculated by the equation:

$$Ph = \text{Spec. Gravity} \times 0.433 \text{ psi/ft} \times \text{Depth.}$$

Field service supervisors generally agree that field procedures are well established to prevent significant errors in fluid density. Most agree that it is rare for fluid density to vary by more than 0.2 lb/gal from specified density. To get some idea of the magnitude of uncertainty that might occur from the maximum 0.2 lb/gal error, the parameters of Well No. 2 will be used. A 10 lb/gal brine, a fluid head of 2791 ft, and an ISIP = 830 psi, results in a fluid head of 1450 psi. These parameters resulted in a BHTP of 2280 psi and a frac gradient of 0.82 psi/ft. If a maximum error occurred and 10.2 lb/gal brine was pumped into the wellbore under the same conditions, the new fluid head would be:

Ph = 1.224 Spec. Gravity x 0.433 psi/ft x 2791 ft = 1479 psi.

The bottom hole treating pressure would calculate as follows:

BHTP = ISIP + Ph = 830 + 1479 = 2309 psi.

The resultant frac gradient would be 0.83 psi/ft. The uncertainty of the frac gradient varying from 0.82 psi/ft to 0.83 psi/ft is insignificant.

Table 10-1A gives the pressure at the top of Mt. Simon in each well at the facility using the established 0.75 psi/ft maximum gradient.

10.2.4 Bottomhole Temperature and Pressure

An original bottomhole temperature was not recorded during the drilling and completion of any of the Vickery wells.

A temperature of 75.30F at 2500 ft was measured on September 19, 1983 in Well No. 6. This temperature gives a gradient of 1.00F/100 ft using an average surface temperature of 50.50F.

An original bottomhole pressure was measured during a drill stem test in Well No. 1 on March 16, 1972 before injection of waste was initiated. A pressure of 1132 psi was recorded at 2745 ft after swabbing the hole. This pressure gives a pressure gradient of 0.412 psi/ft.

Using a pressure gradient of 0.412 psi/ft gives a pressure of 1157 psi at 2808 ft, the top of the Mt. Simon in the #1-A disposal well. This pressure is assumed to be the original BHP at that depth. Table 10-2 shows the bottomhole temperature and pressure corresponding to depth for all the Vickery wells.

10.2.5 Chemical Characteristics of Formation Fluid

Formation water samples were obtained from two wells, Well No. 1 and Well No. 4 before injection was initiated (1972 and 1976, respectively). The analyses are presented in Table 10-3. The formation fluid is a sodium chloride solution with calcium/

TABLE 10-1A

CALCULATED MAXIMUM FORMATION PRESSURE

Well Number	Depth from Ground Level (Feet)	Pressure (psi)
1A	2798	2031
2	2794	2096
3	2789	2092
4	2803	2102
5	2782	2087
6	2786	2090

Maximum pressures are calculated based on a pressure gradient of 0.75 psi/foot of well depth, and the depth to the top of the Mt. Simon.

TABLE 10-2

MEASURED BOTTOMHOLE PRESSURES (BHP) AND TEMPERATURES (BHT)

DATE	WELL	MEASURED DEPTH ft	MEASURED BHP1 psi	MEASURED BHT °F	WELLBORE FLUID GRADIENT2 psi/ft	TOP OF MT. SIMON DEPTH ft	TOP OF MT. SIMON BHP psi	FORMATION FLUID GRADIENT3 psi/ft	MT. SIMON DATUM (-2192 subsea) DEPTH ft	MT. SIMON DATUM (-2192 subsea) BHP psi
25-Aug-87	1A	2735	1314.3	71.5	0.433	2808	1346	0.466	2808	1346
12-Sep-87	2	2750	1293.6	66.5	0.433	2803	1317	0.466	2808	1319
15-Jul-87	3	2841	1312	64.5	0.433	2800	1294	0.466	2810	1299
25-Aug-87	4	2735	1269.9	70.1	0.433	2812	1303	0.466	2810	1302
11-Sep-87	5	2735	1315.6	74.2	0.433	2791	1340	0.466	2810	1348
16-Aug-87	6	2735	1312.04	70.0	0.433	2796	1338	0.466	2807	1344

1Wells were shut in 36 hours prior to measurements but pressure was continuing to decline.

2Wells were filled with fresh water.

3Formation in the interwell area is saturated with waste stream (1.074 s.g.).

TABLE 10-3

FORMATION WATER ANALYSES

	Well No. 1 (Mt. Simon) by Halliburton 5-5-72	Well No. 1 (Mt. Simon) by Dowell 4-10-72	Well No. 4 (Mt. Simon) by CWM Laboratory August, 1976
Specific Gravity	1.095 at 75 °F	1.1 at 60 °F	--
Viscosity, cp	1.38 at 80 °F	--	--
pH, pH units	6.4	6.0	--
Total Dissolved Solids, mg/l	126,000	126,315	--
Chlorides, mg/l	78,000	78,000	83,000
Sulfate, mg/l	817	760	--
Calcium, mg/l	11,900	11,750	--
Magnesium, mg/l	2,250	2,250	--
Sodium, mg/l	33,100	33,500	--
Iron, mg/l	0	--	--
Barium, mg/l	--	--	--
Strontium, mg/l	--	--	--
Bicarbonate, mg/l	49	55	--
Sample Method	DST	DST	Air Lift until Cl-Stabilize
Sample Depth, Ft	2757 to 2927	2757 to 2927	--

NOTES:

mg/l = milligrams per liter   cp = centipoise

°F = degrees Fahrenheit   DST = drillstem test

-- denotes no information available

magnesium sulfate. The Mt. Simon sample from Well No. 4 was analyzed for chlorides only, and the chloride value from this well better represents the formation fluid since the well was backflowed until the chloride value of the formation water stabilized. The other samples may have been slightly diluted with drilling fluid or mud filtrate.

10.2.6 Waste Water Compatibility

Compatibility testing with formation water was done by Halliburton in conjunction with completion of Well No. 1. The testing for Well No. 1 demonstrated that mixing of the injected waste water with connate water resulted in precipitation of calcium sulfate. For this reason, a fresh water buffer fluid was injected into each newly constructed well to displace connate water away from the wellbore and ahead of the waste fluid front. For Well No. 1 core, the Halliburton tests were conducted with connate water, waste effluent, and a 1:1 mixture of connate water:waste. Very minor differences in permeability were encountered.

The permeability of the Precambrian basement to brine or waste was not tested. Permeability to air in a sample from 2926.7 feet in Disposal Well No. 1 was less than .0005 md (the limit of the test equipment) and porosity was .6 percent. The lithology of the basement in the No. 1 well was petrographically described as an alkali feldspar granite.

Testing by ERCO Petroleum Services, Inc. was done on a Mt. Simon core plug from Well No. 5 (from 2,850 ft.). Two acid wastes were injected with little change in the base permeability. However, some fines were generated as a result of acid reaction with the dolomitic portion of the matrix

In core testing, fines are free to exit the core, usually resulting in increased permeability due to acidization. Downhole, fines are not free to migrate out of the test media; therefore, formation of calcium sulfate and small fines could actually decrease permeability and serve to channel flow into areas of silica cementation. Permeability could also increase if the increased flow area due to acid reaction exceeds the flow area plugged due to precipitates and fines.

Core flow testing was done by ERCO Petroleum Services, Inc. to determine core compatibility of various blends. Core material from Well Nos. 2, 4, and 5 was evaluated, In each case permeability reductions occurred due to formation of mobile fines generated from acid reaction with the core matrix.

Vickery has conducted both core analysis and core compatibility testing in conjunction with the Waste Analysis Plan for evaluating future wastes.

Testing has shown that the Mt. Simon contains sufficient clay to exhibit sensitivity to fresh water but with proper pretreatment or blending, the Vickery waste stream is safely injected.

10.3 Containment Interval

10.3.1 Lithology, Thickness

The containment interval is composed of alternating sequences of carbonates and clastics of the Rome, Conasauga, Kerbel and Knox Formations. The lithology of these formations was discussed in detail in Attachment D of this document.

The thickness of the containment interval is approximately 440 feet and includes zones which will arrest fluid movement as well as several "bleed off" zones. A "bleed off" zone is a stratigraphic interval containing greater hydraulic conductivity (related to permeability) than the intervals above and below it. When groundwater flowlines cross a boundary between formations with different hydraulic conductivities they are refracted. In a system composed of heterogenous layers and subject to a hydraulic gradient oriented perpendicular to the layering, fluid will move in a direction basically perpendicular to the layering in low conductivity units and basically parallel to the layering in high conductivity units on either side of the interface. Figure 10-11 demonstrates this concept. Fluid flow is dispersed laterally in a bleed off zone, and pressure gradient is significantly reduced in the down gradient layers. A more complete treatment of this phenomena can be found in Freeze and Cherry (1979), Chapter 5.1.

In 1993 a monitor well was installed at the interface of the Knox and Kerbel formations that is capable of monitoring formation fluid chemistry periodically and formation pressures continuously. This well is currently samples on an annual basis to evaluate

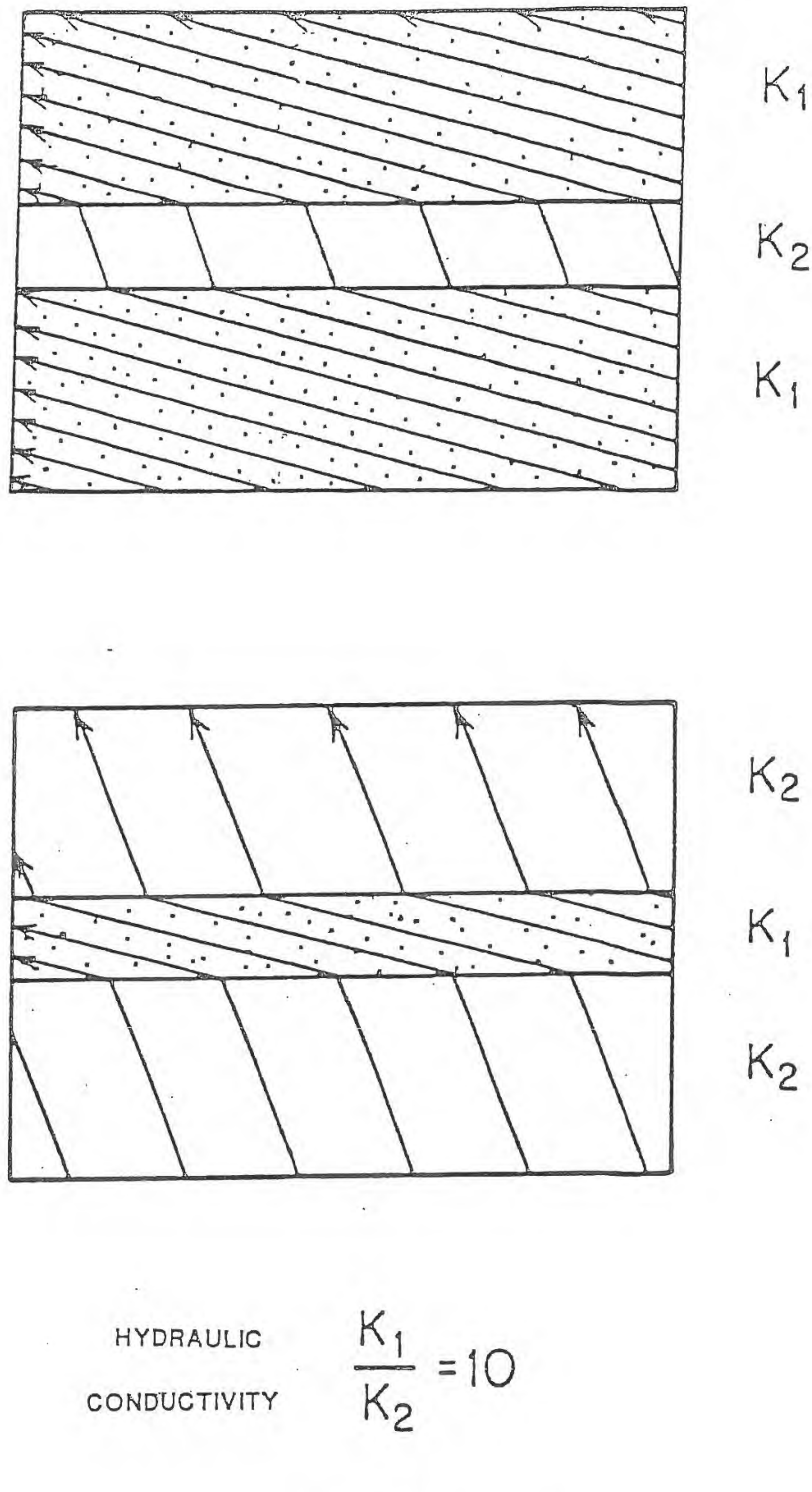


FIGURE 10-11

REFRACTION OF FLOWLINES IN LAYERED SYSTEMS water quality and an annual report that also includes formation pressure data is prepared each year.

There has been no excess buildup in formation pressure from injection activity and water chemistry has remained stable.

The Rome Formation directly overlies the Mt. Simon injection interval. The Middle Rome dolomitic sandstone will act as a significant bleed off zone to reduce upward acting injection zone pressures.

10.3.2 Porosity and Permeability

10.3.2.1 Testing History

Porosity and permeability testing has been carried out on the Vickery cores in multiple stages, utilizing equipment of different sensitivity. Within the containment interval, stratigraphic zones of low permeability are of particular interest, and the capability of the core testing procedure to detect and measure low permeabilities is critical.

Waste Disposal Wells Nos. 4 and 5 were the most extensively cored within the containment interval. Initial testing of these cores, in 1976 and 1980 respectively, was recorded to a minimum permeability to air of only .1 md and minimum porosity of 3 percent. The cores were sampled every foot in these analyses, creating an extensive, nearly continuous data record, but not truly adequate for evaluating low permeability zones.

In the fall of 1987 Vickery had additional porosity and permeability testing performed on selected containment interval zones from Disposal Wells Nos. 2, 4 and 5, with No. 4 and 5 being the most extensively tested. The selected core plugs were tested for permeability to air to .01 md, and permeability to 100,000 ppm NaCl brine to a minimum of .0001 md.

In the Fall of 1989, a relatively minor amount of porosity and permeability testing was carried out in conjunction with significant petrographic work performed on the cores from Disposal Wells Nos. 1, 2, 4 and 5. This work involved testing permeability to air to a minimum of .0001 md, and porosity to a minimum of .1 percent. Additionally, three Lower Rome Dolomite (Shady) samples, one Conasauga and one Knox sample were tested for vertical permeability to 100,000 ppm NaCl brine to a minimum of .000001 md.

In 1992 testing was completed on an extensive round of flow through studies using Vickery core materials and synthetic waste. Also, significant additional petrography work was performed before and after the flow through tests. The complete report of this testing consisted of nine volumes, and was submitted to the USEPA and ODNR. The testing confirmed the conservative nature of the input data for the reservoir modeling.

10.3.2.2 Data Analysis

The varying sensitivities of the testing described in the preceding section makes analysis of low permeability zones within the containment interval rather difficult since a large amount of the rock materials sampled have permeabilities less than the value that could be measured at the time of testing. In an attempt to overcome this problem, average porosity and permeability for various formations, or formation segments, will be grouped according to the sensitivity of the data utilized, i.e. permeability values measured to .1 md, .01 md and .0001 md.

Since the equipment utilized in all the various analyses was capable of recording maximum porosity and permeability values encountered but not the minimum values, all the following "average" data should be regarded as conservative since the recorded average porosity and permeability are less than the true population average.

All porosities are averaged arithmetically. All vertical permeabilities are averaged using the harmonic mean. There is some uncertainty regarding the best measurement statistic for the "average" horizontal permeability, the choice being either the arithmetic mean or the geometric mean. The geometric mean is often markedly lower than the arithmetic mean for a sampled population.

Richardson, et.al. (1987) states that,

"It is usually observed that arithmetic averages of foot-by-foot horizontal permeabilities measured parallel to the bedding planes in the cores agree with permeabilities calculated from well tests. This is logical because ... arithmetic averaging assumes that flow occurs through the various strata parallel to the bedding planes. In this conceptual model, a consistent assumption is that vertical permeabilities measured perpendicular to the bedding planes should be averaged harmonically (in series) to reflect flow in the vertical direction..."

Fetter (1988), referring to hydraulic conductivity values obtain from tests of several monitoring wells areally distributed in the same aquifer, states that,

"An arithmetic mean of such a sample population tends to give more weight to the more permeable values. Some hydrogeologists believe that a more representative description of the average hydraulic conductivity of a hydrologic unit is the geometric mean. This is determined by taking the natural log of each value, finding the mean of the natural logs and then obtaining the exponential (ex) of that value to arrive at the geometric mean."

Vickery believes that arithmetic means are the more appropriate measurement for representing horizontal permeability in layered systems when utilizing the type of data available at the Vickery site. Both arithmetic and geometric values are presented in several tables in this document for comparative purposes.

Table 10-4 summarizes the porosity and permeability to air data, Table 10-5 summarizes permeability to 100,000 ppm NaCl brine. Table 10-5A provides details of the brine permeability testing. Table 10-5 demonstrates the difference in arithmetic verses geometric means for horizontal permeability.

The values of porosity and permeability used to define the various layers of the reservoir model are conservative when compared to the measured values indicated in Tables 10-4 and 10-5. Figure 10-12 shows the porosity and permeability values used in the model.

Figure 10-13 shows porosity and permeability data from Disposal Well No. 4 and the subdivision of the Rome Formation. Figure 10-14 shows the subdivisions of the Conasauga Formation with data obtained from the No. 5 well.

10.3.2.3 Porosity Development and Diagenesis

From the extensive petrographic study carried out by Vickery

on the cores of Disposal Wells Nos. 2, 4 and 5 the following generalizations can be made about containment interval porosity development, and diagenesis.

TABLE 10-4

POROSITY AND PERMEABILITY TO AIR

Formation		Testing Period		
		pre 1980	1987	1989
BLACK RIVER (Actually in Confining Zone, data from ODNR No.1 M. and B. Asphalt, Seneca Co., OH)	N	0	0	17
	K_h(md)			.0012
	ϕ_h(%)			1.96
	N	0	0	17
	K_v(md)			.00054
	ϕ_v(%)			NA
KNOX	N	39	2	0
	K_h(md)	17.06	62.65	
	ϕ_h (%)	6.92	13.85	
	N	0	2	8
	K_v(md)		.22	.0002
	ϕ_v(%)		10.6	7.25
KERBEL	N	149	7	0
	K_h(md)	26.28	63.68	
	ϕ_h(%)	11.92	11.57	
	N	0	7	11
	K_v(md)		.22	.0011
	ϕ_v(%)		11.65	10.72
CONASAUGA	N	177	7	0
	k_h(md)	50.14	85.05	
	ϕ_h (%)	12.05	14.36	
	N	0	7	27
	K_v(md)		.076	.00037
	ϕ_v(%)		13.63	11.21
UPPER ROME DOLOMITE	N	34	3	0
	K_h(md)	1.189	.593	
	ϕ_h(%)	4.32	6.5	
	N	0	3	2
	K_v(md)		.024	.00018
	ϕ_v(%)		4.43	4.15

TABLE 10-4 (Page 2 of 2)

MIDDLE ROME DOLOMITIC SAND	N	30	3	0
	K_h (md)	9.50	157.0	
	ϕ_h (%)	10.27	16.5	
	N	0	3	7
	K_v (md)		.075	.00023
	ϕ_v (%)		14.07	9.01
LOWER ROME DOLOMITE (SHADY)	N	28	1	0
	K_h (md)	.574	.02	
	ϕ_h (%)	4.29	2.3	
	N	0	1	14
	K_v (md)		.01	.00013
	ϕ_v (%)		4.8	3.61

N = # of Samples
K_v= Harmonic mean
K_h= Arithmetic mean
ϕ_h= Arithmetic mean

TABLE 10-5A

SUMMARY OF POROSITY AND LIQUID PERMEABILITY TESTING
(Permeability Tests Used 100,000 ppm NaCl as the Saturant Fluid)

Formation*	Depth (ft)	Well #	Test Date** (Year)	Kh (md)	Kv (md)	Øh (%)	Øv (%)
Knox	2387.3	5	1989		.000024		2.4
Knox	2390.0	5	1984		.0034		6.3
Knox	2394.4	5	1987	.56		8.4	
Knox	2394-95	5	1987		.01		8.1
Knox	2402.0	5	1987	12.0		19.3	
Knox	2402-03	5	1987		6.7		13.1
Kerbel	2442.0	4	1987	114.0		14.9	
Kerbel	2442-43	4	1987		12.0		14.3
Kerbel	2448.3	4	1987	.06		6.7	
Kerbel	2448-49	4	1987		.01		6.2
Kerbel	2454.2	4	1987	.29		9.2	
Kerbel	2454-55	4	1987		.25		9.6
Kerbel	2492.3	4	1987	65.0		21.6	
Kerbel	2492-93	4	1987		4.3		21.0
Kerbel	2436.1	5	1987	.39		9.8	
Kerbel	2436-37	5	1987		.22		9.0
Kerbel	2438.4	5	1987	.08		8.4	
Kerbel	2438-39	5	1987		.04		8.8
Kerbel	2440.0	5	1984	.75		10.9	
Kerbel	2445.1	5	1987	1.4		10.4	
Kerbel	2445-46	5	1987		1.1		12.6
Kerbel	2477.0	5	1984	8.1		26.8	
Conasauga	2497.1	2	1987	35.0		11.3	
Conasauga	2497-98	2	1987		.17		10.8
Conasauga	2569.9	2	1987	.02		12.5	
Conasauga	2569-70	2	1987		.01		12.7
Conasauga	2509.9	4	1989		.000588		4.7
Conasauga	2518.2	4	1987	.001		5.4	
Conasauga	2518-19	4	1987		.0007		6.4
Conasauga	2546.9	4	1987	43.0		19.9	
Conasauga	2546-47	4	1987		.06		15.3
Conasauga	2564.5	4	1987	49.0		18.6	
Conasauga	2564-65	4	1987		13.0		15.4
Conasauga	2507.0	5	1984		.0034		6.3

TABLE 10-5A

SUMMARY OF POROSITY AND LIQUID PERMEABILITY TESTING
(Permeability Tests Used 100,000 ppm NaCl as the Saturant Fluid)

Formation*	Depth (ft)	Well #	Test Date** (Year)	Kh (md)	Kv (md)	Øh (%)	Øv (%)
Conasauga	2519.6	5	1987	133.0		24.2	
Conasauga	2519-20	5	1987		1.8		23.7
Conasauga	2525.0	5	1984	32.1		22.8	
Conasauga	2538.0	5	1984	27.0		14.6	
Conasauga	2571.3	5	1987	.01		8.6	
Conasauga	2571-72	5	1987		.0003		11.1
Upper Rome	2585.4	5	1987	.08		7.5	
Upper Rome	2585-86	5	1987		.01		4.1
Upper Rome	2590.6	5	1987	.0008		3.9	
Upper Rome	2590-91	5	1987		.01		3.0
Upper Rome	2594.8	5	1987	.001		8.1	
Upper Rome	2594-95	5	1987		.001		6.2
Middle Rome	2704.3	4	1987	.01		7.7	
Middle Rome	2704-05	4	1987		.005		7.0
Middle Rome	2727.2	4	1987	5.6		16.7	
Middle Rome	2727-28	4	1987		.03		14.2
Middle Rome	2730.2	4	1987	311.0		25.1	
Middle Rome	2730-31	4	1987		11.0		21.0
Lower Rome	2800.0	4	1989		.000022		0.2
Lower Rome	2807.5	4	1989		.000092		1.4
Lower Rome	2786.6	5	1987	.0001		2:3	
Lower Rome	2786-87	5	1987		.0006		4.8
Lower Rome	2790.5	5	1989		.000036		3.9

* Formation boundaries utilized here are tied to the determinations made during the 1989 petrographic study performed on the CWM Vickery cores. Please refer to Table 9-1 and Appendix P.

**1984 and 1987 data is in Appendix I. 1989 data is in Appendix P.

Kh = Liquid permeability in a horizontal plug.
Kv = Liquid permeability in a vertical plug.
Øh = Porosity in a horizontal plug.
Øv = Porosity in a vertical plug.

TABLE 10-5

PERMEABILITY TO 100,000 PPM NaCl BRINE

Formation*	N	Kh_a (md)	Kh_g (md)	N	Kv (md)
Knox	2	6.28	2.59	3	.0000951
Kerbel	9	20.23	1.48	7	.0519
Conasauga	9	35.46	2.285	8	.00131
Upper Rome Dolo.	3	.027	.0040	3	.0025
Mid Rome Sand	3	105.5	2.592	3	.0129
Lower Rome Dolo.	1	.0001	.0001	4	.0000466

N = # of Samples
Kv= Harmonic mean
Kh_a = Arithmetic mean
Kh_g = Geometric mean

* Determination of which formation particular sample depths represent is based on the 1989 petrographic study, see Table 9-1. See Table 11-5A for details of samples utilized in this table.

FIGURE 10-12

Hydraulic properties used for analysis of vertical pressurization and waste migration.

Model Layer	Unit	Horizontal Permeability (md)	Vertical Permeability (md)	Porosity
1	Black River	0.10	0.01	0.05
2	Black River	0.10	0.01	0.05
3	Black River	0.10	0.01	0.05
4	Wells Creek	0.014	0.0014	0.05
5	Knox	5	0.5	0.05
6	Knox	5	0.5	0.05
7	Knox	5	0.5	0.05
8	Kerbel	20	2	0.10
9	Kerbel	20	2	0.10
10	Conasauga Silty Sand	20	20	0.15
11	Conasauga Shale	0.014	0.0014	0.06
12	Conasauga Shale	0.014	0.0014	0.06
13	Conasauga Silty Sand	35	35	0.15
14	Conasauga Silty Sand	35	35	0.15
15	Conasauga Silty Sand	35	35	0.15
16	Conasauga Silty Sand	35	35	0.15
17	Rome Dolomite	0.05	0.005	0.03
18	Rome Dolomite	0.05	0.005	0.03
19	Rome Dolomite	0.05	0.005	0.03
20	Rome Dolomite	0.05	0.005	0.03
21	Rome Dolomite	0.05	0.005	0.03
22	Rome Silty Sand	5	5	0.10
23	Rome Silty Sand	5	5	0.10
24	Rome Dolomite	0.006	0.0006	0.03
25	Rome Dolomite	0.006	0.0006	0.03
26	Rome Dolomite	0.006	0.0006	0.03
27	Rome Dolomite	0.006	0.0006	0.03
28	Rome Dolomite	0.006	0.0006	0.03
29	Rome Dolomite	0.006	0.0006	0.03
30	Rome Dolomite	0.006	0.0006	0.03
31	Mt. Simon Sandstone	42	42	0.15
32	Mt. Simon Sandstone	42	42	0.15
33	Mt. Simon Sandstone	42	42	0.15

DISPOSAL WELL NO.4

ROME FORMATION

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS HORIZONTAL	PERMEABILITY MILLIDARCYS VERTICAL	POROSITY PERCENT	
177	2694.3	<0.10		3.0	
178	2695.5	<0.10		<3.0	
179	2696.5	<0.10		4.4	
180	2697.5	<0.10		<3.0	
181	2698.5	<0.10		3.8	UPPER DOLOMITE
182	2699.5	0.12		4.9	
183	2700.5	<0.10		5.8	
184	2701.5	<0.10		6.5	
185	2702.5	<0.10		6.8	
186	2703.5	<0.10		5.3	
187	2704.5	<0.10		7.1	
188	2705.5	<0.10		<3.0	
189	2706.5	<0.10		9.3	
190	2707.5	1.2		9.6	
191	2708.5	1.7		10.3	
192	2709.5	2.0		10.2	
193	2710.5	1.6		11.0	
194	2711.5	8.6		9.8	
195	2712.5	1.4		13.0	
196	2713.5	5.4		15.1	
197	2714.5	1.0		15.4	
198	2715.5	3.6		13.9	
199	2716.5	0.21		10.0	
200	2717.5	30.		19.8	
201	2718.5	44.		21.3	
202	2719.5	0.17		9.5	
203	2720.5	1.2		10.5	
204	2721.5	<0.10		9.7	
205	2722.5	1.2		9.8	MIDDLE DOLOMITIC SANDSTO.
206	2723.5	0.13		5.6	
207	2724.5	0.85		10.6	
208	2725.5	5.2		12.2	
209	2726.5	10.		15.5	
210	2727.5	163.		24.3	
211	2728.5	0.30		9.4	
212	2729.5	0.83		11.0	
213	2730.5	<0.10		3.0	
214	2731.5	0.20		6.4	
215	2732.5	<0.10		<3.0	
216	2733.5	<0.10		<3.0	
217	2734.5	<0.10		<3.0	
218	2735.5	0.62		8.8	
219	2736.5	<0.10		3.7	
220	2797.5	<0.10		<3.0	
221	2798.5	<0.10		<3.0	
222	2799.5	0.27		4.9	
223	2800.5	<0.10		<3.0	
224	2801.5	<0.10		<3.0	
225	2802.5	<0.10		6.3	
226	2803.5	<0.10		4.0	
227	2804.5	5.4		8.3	
228	2805.5	<0.10		<3.0	LOWER DOLOMITE (SHADY)
229	2806.5	<0.10		<3.0	
230	2807.5	<0.10		<3.0	
231	2808.5	<0.10		<3.0	
232	2809.5	<0.10		<3.0	
233	2810.5	<0.10		<3.0	
234	2811.5	<0.10		<3.0	
235	2812.5	<0.10		<3.0	

MAJOR HORIZONTAL

FIGURE 10-13

POROSITY AND PERMEABILITY DIVISIONS

ENTIRE FORMATION NOT CORED

DISPOSAL WELL NO.5

CONASAUGA FORMATION

SILTY SANDSTONE

SMP. NO.	DEPTH	PERM. TO AIR MD. MAXIMUM	90 DEG.	VERT.	POROSITY GEX. FLD.
105	2490.0-91.0	17.0	15.0		11.7
106	2491.0-92.0	5.3	4.6		11.4
107	2492.0-93.0	4.2	3.8		9.1
108	2493.0-94.0	5.6	3.8		8.0
109	2494.0-95.0	79.0	63.0		5.1
110	2495.0-96.0	*	2.9		6.7
111	2496.0-97.0	*	3.5		9.3
112	2497.0-98.0	4.0	3.7		11.0

SILTY SHALE

SMP. NO.	DEPTH	PERM. TO AIR MD. MAXIMUM	90 DEG.	VERT.	POROSITY GEX. FLD.
113	2498.0-99.0	<0.1	<0.1		5.3
114	2499.0-00.0	<0.1	<0.1		3.8
115	2500.0-01.0	<0.1	<0.1		4.2
116	2501.0-02.0	<0.1	<0.1		5.3
117	2502.0-03.0	*	<0.1		5.1
118	2503.0-04.0	<0.1	<0.1		4.6
119	2504.0-05.0	<0.1	<0.1		4.2
120	2505.0-06.0	*	<0.1		4.0
121	2506.0-07.0	<0.1	<0.1		3.8
122	2507.0-08.0	<0.1	<0.1		3.6
123	2508.0-09.0	<0.1	<0.1		5.1
124	2509.0-10.0	<0.1	<0.1		7.6
125	2510.0-11.0	<0.1	<0.1		9.0
126	2511.0-12.0	<0.1	<0.1		8.4
127	2512.0-13.0	<0.1	<0.1		7.2
128	2513.0-14.0	<0.1	<0.1		14.3
129	2514.0-15.0	<0.1	<0.1		6.5
130	2515.0-16.0	0.7	0.6		9.5
131	2516.0-17.0	1.3	0.6		10.0

SILTY SANDSTONE

SMP. NO.	DEPTH	PERM. TO AIR MD. MAXIMUM	90 DEG.	VERT.	POROSITY GEX. FLD.
132	2517.0-18.0	27.0	25.0		12.6
133	2518.0-19.0	141.0	132.0		19.4
134	2519.0-20.0	431.0	399.0		22.3
135	2520.0-21.0	37.0	36.0		15.5
136	2521.0-22.0	29.0	23.0		13.1
137	2522.0-23.0	72.0	68.0		21.0
138	2523.0-24.0	53.0	48.0		18.6
139	2524.0-25.0	118.0	110.0		20.8
140	2525.0-26.0	108.0	98.0		22.3
141	2526.0-27.0	58.0	58.0		13.1
142	2527.0-28.0	18.0	15.0		12.7
143	2528.0-29.0	45.0	43.0		17.1
144	2529.0-30.0	6.4	5.6		9.5
145	2530.0-31.0	1.9	0.8		9.6
146	2531.0-32.0	22.0	18.0		12.2
147	2532.0-33.0	36.0	29.0		11.1
148	2533.0-34.0	54.0	45.0		14.1
149	2534.0-35.0	408.0	243.0		14.2
150	2535.0-36.0	57.0	54.0		14.2
151	2536.0-37.0	69.0	67.0		13.3
152	2537.0-38.0	78.0	75.0		13.1
153	2538.0-39.0	60.0	59.0		13.8
154	2539.0-40.0	60.0	57.0		14.1
155	2540.0-41.0	90.0	85.0		14.2
156	2541.0-42.0	68.0	67.0		15.4
157	2542.0-43.0	62.0	59.0		15.4
158	2543.0-44.0	83.0	79.0		19.2
159	2544.0-45.0	126.0	114.0		19.9
160	2545.0-46.0	62.0	56.0		17.7
161	2546.0-47.0	52.0	51.0		20.0
162	2547.0-48.0	45.0	42.0		13.1
163	2548.0-49.0	45.0	43.0		12.7
164	2549.0-50.0	73.0	70.0		16.3
165	2550.0-51.0	54.0	54.0		17.9
166	2551.0-52.0	29.0	28.0		19.3
167	2552.0-53.0	*	20.0		10.3
168	2553.0-54.0	40.0	39.0		14.9
169	2554.0-55.0	64.0	61.0		12.5
170	2555.0-56.0	5.1	4.6		15.9
171	2556.0-57.0	*	94.0		19.2
172	2557.0-58.0	*	85.0		14.6
173	2558.0-59.0	11.0	10.0		15.4
174	2559.0-60.0	57.0	41.0		16.6
175	2560.0-61.0	40.0	34.0		20.8
176	2561.0-62.0	36.0	34.0		21.3
177	2562.0-63.0	24.0	23.0		16.3
178	2563.0-64.0	11.0	10.0		8.7
179	2564.0-65.0	9.6	7.9		9.7
180	2565.0-66.0	2.2	1.1		13.6
181	2566.0-67.0	0.3	0.2		11.3
182	2567.0-68.0	3.6	3.2		12.0
183	2568.0-69.0	2.0	1.4		15.4
184	2569.0-70.0	1.9	1.9		10.8
185	2570.0-71.0	1.8	1.7		9.3
186	2571.0-72.0	<0.1	<0.1		5.7
187	2572.0-73.0	0.1	0.1		6.7
188	2573.0-74.0	<0.1	<0.1		7.8
189	2574.0-75.0	1.2	1.1		9.5
190	2575.0-76.0	0.4	0.4		6.9
191	2576.0-77.0	0.3	0.2		5.6
192	2577.0-78.0	0.8	0.4		8.6
193	2578.0-79.0	<0.1	<0.1		5.4

FIGURE 10-14

MAJOR HORIZONTAL

POROSITY AND PERMEABILITY DIVISIONS

10.3.2.3.1 Rome Formation

The Rome Formation can be divided into three units. The lowermost unit is a sandy grainstone dolomite. The middle section is a dolomitic fine to very fine grained sandstone. The upper unit is a sandy grainstone dolomite similar to the lowermost unit.

Although very few samples were examined in detail from the Middle Rome, diagenetic events affecting porosity development in the Middle Rome include initial quartz overgrowth development and K-feldspar development which is often followed by extensive precipitation by pore-filling finely crystalline dolomite. Dolomitization was followed by dissolution of unstable framework grains leading to the formation of moldic and intragranular pores. In many cases, dolomite cement appears to have occluded intergranular pores, and therefore the predominant pore types are intragranular and moldic. These pores appear to be very poorly interconnected and permeability values are typically below 1 md.

Dolomitized grainstones of the uppermost and lowermost Rome contain very low levels of visible porosity and contain high amounts of pore filling dolomite cement. Rare visible pores are generally isolated and consist largely of moldic and vuggy dissolution pores. A small number of fractures occur in both the lower and upper Rome. Blue-light fluorescent microscopy and standard thin section petrography show that the majority of fractures are laterally discontinuous and appear occluded laterally by dolomite cement, and less commonly by calcite cement. Some fractures are laterally continuous and display especially sharp breaks, free of mineralization throughout the length of the fracture. These fractures appear to have been induced, perhaps during the coring process. Permeability to air values in the upper and lower Rome are generally below 1 md and in many cases, below 0.0001 md. Vertical permeability to 100,000 ppm NaCl brine measured in the lower Rome averaged 0.000047 md from 4 samples.

10.3.2.3.2 Conasauga Formation

The Conasauga is variable lithologically, consisting of finely interlaminated siltstones, very fine-grained sandstones and dolomites in the upper portion of the formation, and dolomite cemented fine to very fine-grained sandstone in the lower Conasauga.

In the upper portion of the Conasauga, visible porosity is negligible within dolomite and clay-rich siltstone laminations. Visible porosity can also be very low along relatively clean carbonate cemented very fine grained sandstone laminations. Some fine grained sandstone laminations display well developed visible porosity. Burial diagenetic influences in these sandstones include early formation of poorly developed grain-coating chlorite, which was succeeded by quartz overgrowth cementation, which was followed in turn by K-feldspar overgrowth cementation, detrital framework grain dissolution, and pore-bridging illite precipitation. Dolomite cement appears to post-date illite formation, occurring in coarse rhombic pore-filling and occasionally grain replacing crystals. Visible porosity can be as high as 23% within thin sandstone beds in the upper Conasauga. In such beds, intergranular and secondary dissolution pores are present in nearly equal proportions and often appear well interconnected laterally. However, such beds are thin and are often bounded vertically by relatively tight beds (i..e. dolomites, dolomitic siltstones).

With the exception of the lowermost 15 feet of the lower Conasauga (which is tightly cemented by pervasive dolomite cement), the lower Conasauga consists of fairly clean thick-bedded sandstone which often displays high amounts of visible porosity in thin section. These sandstones display similar diagenetic relationships to those of clean sandstones in the upper Conasauga. Visible porosity commonly exceeds 15%, with abundant intergranular and secondary pores. Measured permeability values in this interval commonly exceed 50 md.

10.3.2.3.3 Kerbel Formation

The Kerbel consists largely of relatively clean, very fine to fine grained sandstones that contain variable amounts of dolomite cement. Visible porosity in the Kerbel ranges from 4.0-20% with pore-filling dolomite cement acting as the controlling factor in porosity distribution. Dolomite cement is both grain replacing and pore-filling (most common mode of occurrence) and often displays a very even distribution of medium subhedral crystals. Dolomite cement appears to have post-dated quartz and feldspar overgrowth cementation and predates the development of secondary grain-moldic and intragranular pores. Dolomite cement is present in almost every sandstone examined in the Kerbel and occurs most commonly within intergranular pores. Where dolomite cement exceeds 30%, visible porosity rarely exceeds 10%. Dolomite cement not only effects permeability by reducing overall porosity, it appears to also effect permeability by reducing overall pore size and occluding interconnection between pores.

Sandstones with high amounts of porosity occur in both the upper and lower Kerbel, in which measured whole core permeability typically ranges from 10-50 md. However, sandstones containing high amounts of dolomite cement are common with permeability values often less than 5 md.

10.3.2.3.4 Knox Formation

The Knox samples from Well No. 4 and Well No. 5 consist of dolomite and mixed dolomite/sandstone. Visible porosity is especially low within relatively pure dolomite grainstones, where the dominant form of porosity is isolated moldic and vuggy dissolution pores. Intergranular and moldic dissolution porosity can be well developed along sandstone beds. Moldic pores are sometimes well developed in sandy dolomite beds, but appear poorly interconnected. Intergranular and secondary pores within dolomitic sandstone laminations often appear locally well interconnected, however, such laminations are commonly laterally and vertically discontinuous. Fractures are present in the Knox, but like those of the Rome Formation, most are laterally discontinuous due to dolomite cementation. There are also fractures that display especially clean breaks with no evidence whatsoever of mineralization - these are believed to have been induced during coring.

In 1993 a monitor well was installed at the interface of the Knox and Kerbel formations that is capable of monitoring formation fluid chemistry periodically and formation pressures continuously. This well is currently samples on an annual basis to evaluate water quality and an annual report that also incluses formation pressure data is prepared each year.

There has been no excess buildup in formation pressure from injection activity and water chemistry has remained stable.

10.3.3 Formation Fracture Gradient

Very little information exists on the regional fracture gradient for formations of the containment interval. According to oilfield service companies contacted the fracture gradient for the formations in the containment interval is .80 psi/ft. This is based on their experience with the Knox formation in Morrow, Holmes and Coshocton Counties. This fracture gradient is .05 psi/ft higher than the 0.75 psi/ft fracture gradient used to establish the maximum wellhead injection pressure at the Vickery site.

10.3.4 Chemical Characteristics of Formation Fluid

A water sample from the Kerbel Formation was obtained from Vickery Well No. 4 before injection was initiated in 1976. The formation fluid at this interval is similar to the Mt. Simon Formation fluid except for a lower chloride content and higher calcium and sulfate content. Formation water analysis results for the Kerbel are included in Table 10-6.

10.3.5 Waste Water Compatibility

Most of the formations in the containment interval have dolomite (CaMg (CO3)2) as a significant mineralogical constituent The general equation for the reaction of dolomite with acid is:

$$CaMg(CO_3)_2 + 4H^+ = Ca^{++} + MG^{++} + 2CO_2 + 2H_2O$$

This chemical reaction results in the neutralization of the acidic waste through the dissolution of dolomite.

URM (1984) states that the dissolution of dolomite and the resultant release of Ca++ in solution may result in the formation of gypsum (CaSO4•nH2O) upon reaction with sulfate in the wastestream, which may precipitate in intergranular or fracture pore spaces. This mineral precipitation would cause a reduction in permeability within the naturally low permeability formations of the containment interval.

Testing of Well No. 1 Mt. Simon sandstone (containing a minor dolomite component) demonstrated that mixing of connate water and injected acidic waste water resulted in the precipitation of calcium sulfate

Results of other studies (International Symposium on Subsurface Injection of Liquid Wastes, 1986), indicate the possibility that the permeability reduction of dolomite samples seen after the samples were flowed with synthetic brine (to obtain repeatable results) then with pickling liquor (acid) was caused by precipitation of iron carbonate.

TABLE 10-6

FORMATION WATER ANALYSES

OF

THE KERBEL

Well No. 4
(Kerbel)
by CWM Laboratory
8-5-76

Specific Gravity	1.067
Viscosity, cp	--
pH, pH units	--
Total Dissolved Solids, mg/l	--
Chlorides, mg/l	62,037
Sulfate, mg/l	1,143
Calcium, mg/l	7,900
Magnesium, mg/l	--
Sodium, mg/l	--
Iron, mg/l	2.18
Barium, mg/l	--
Strontium, mg/l	--
Bicarbonate, mg/l	--
Sample Method	DST
Sample Depth, ft	--

NOTES:

mg/l = milligrams per liter   cp = centipoise

^oF = degrees Fahrenheit   DST = drillstem test

-- denotes no information available

Attachment B

II. Seismic Discussion

5.3 SEISMICITY

The relationship of injection activities to seismic events is an area of concern for regulatory agencies. Vickery can demonstrate that injection activity at the site cannot be related to any known seismic event.

At present, Vickery maintains injection pressures well below the calculated fracture gradient of the Mt. Simon Sandstone, calculated from the wells at the site, so that the threshold for failure will not be exceeded and trigger a seismic event.

Figure 5-27 is a map of the Ohio River Basin showing the degree of seismic risk for the area. Most of Ohio has been determined to be in an area of minor to moderate risk. Figure 5-28 is a somewhat more sophisticated figure from the US Geological Survey showing a 10% probability of a seismic event exceeding a particular acceleration relative to gravity during a 50-year period. The figure indicates that there is a 10% chance of a seismic event occurring that exceeds only 2 to 3 percent of the force of gravity in northeastern Ohio, within 50 years. Figure 5-29 describes the possible damage associated with seismic events of certain magnitudes.

In 1977 a nine station seismic monitoring array became operational in western Ohio (Anna Network), and in 1981 was supplemented by four stations in Indiana. This Ohio-Indiana seismic network was operated by the University of Michigan under contract to the United States Nuclear Regulatory Commission. This contract was discontinued in 1992 according to ODNR. This network was capable of detecting seismic activity which may originate at the Vickery site with a magnitude of approximately 2.0 or greater. This magnitude is near the threshold for human feeling at the epicenter.

Currently, ODNR has a 29 station network of seismographs in Ohio called OhioSeis, The Ohio Seismic Network. The stations are located at colleges, universities, and other institutions throughout Ohio but are primarily concentrated in the most seismically active areas. The systems utilize a desktop computer, internet connection and a Global Position System receiver. The exact epicenter, magnitude and time frame of any seismic activity can be determined in a matter of minutes by checking data from any three or more of the seismograph units. Figure 5-30 identifies the approximate location of these 29 seismic monitoring stations.

Utilizing the data from the Anna Network and the OhioSeis Network, earthquake information depicting seismic events in Ohio since 1776 is shown in Figure 5-31. Figure 5-31A also present the information as in Figure 5-31, the difference is that Figure 5-31A was created using the Ohio Seis Networks Interactive Mapping Utility. A tabulation of these events is given in Table 5-1 and Table 5-2. The figures and tables reveal no seismic activity detected in the vicinity of the Vickery site. Seismic events recorded around Sandusky County are shown in Figure 5-32. Three historical and two recent seismic events are listed below:

> In February of 1975, an earthquake occurred in the south-central portion of Sandusky county about 12 miles south-southwest of the site. Three earthquakes were recorded in north-central Seneca County. Two of those earthquakes occurred in 1936 about 16 miles southwest of the site. The third earthquake occurred in 1961 about 20 miles southwest of the site. These earthquake occurred before injection activities began at the site. The two most recent earthquakes occurring closer to the site occurred in 2010 and were located near Gibsonburg (May, 2010) and Fostoria (February, 2010).

The Vickery facility completed an extensive seismic reflection investigation in late 1989. The results of the study are included in a document entitled "Seismic Reflection Investigation" dated February 1991 by Weston Geophysical Corporation. A copy of that report is included as

Attachment I. The conclusions drawn from that study are included in Attachment I, Section 4. There was no indication of vertical faulting or fracturing of the sedimentary units or the Precambrian surface within the area of the investigation.

The evaluation of the historical seismic record indicates that the Vickery facility is located in an area of relatively little seismic risk. There is no evidence that the injection activities at Vickery during the past four decades have caused any seismic events.

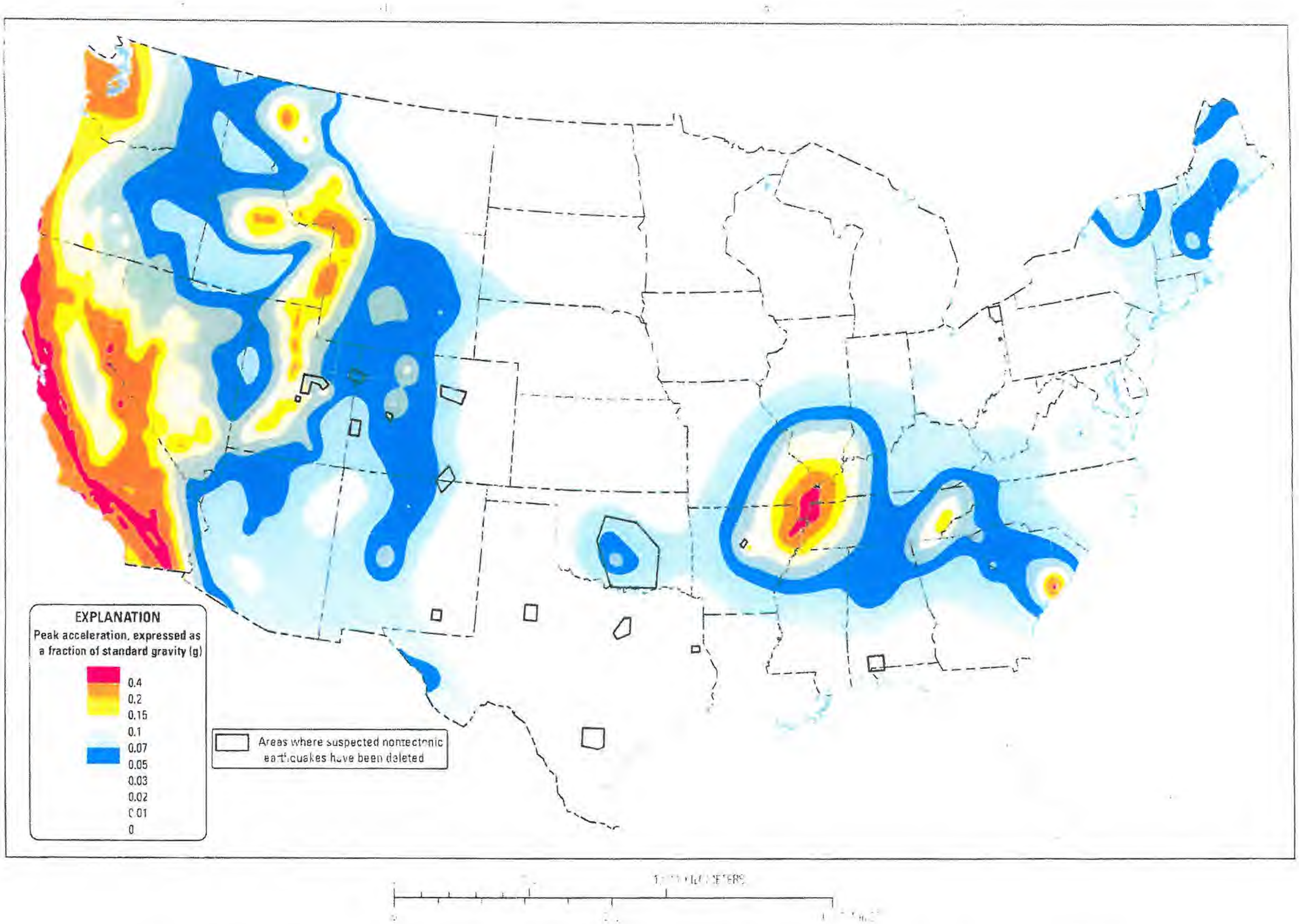


Figure 5-28 **Ten-percent probability of exceedance in 50 years map of peak ground acceleration**

Mailing Address:

ODNR
Division of
Geological Survey
2045 Morse Rd.,
Bldg. C-1
Columbus, OH
43229-6693

Phone:
(614) 265-6576
Fax:
(614) 447-1918

E-Mail
Location Map

Earthquake Contacts:
24 Hour Earthquake Reporting Hotline:
1-855-QuakeOH
1-855-(782-5364)

Seismic Magnitude/Intensity Scales

Scale Magnitude	Mercalli	Description
0-2.9	I	Detected only by sensitive instruments
	II	Felt only by a few persons at rest, especially on upper floors of buildings; delicately suspended objects may swing
	III	Felt noticeably indoors, especially on upper floors of buildings, but not always recognized as earthquake; standing autos may rock slightly; vibrations like a passing truck
2.9-4.1	IV	During the day, felt indoors by many, outdoors by few; at night, some awakened; dishes, windows, doors disturbed; walls make creaking sound; sensation like heavy truck hitting building; standing autos rock noticeably
	V	Felt by most people; some breakage of dishes, windows, and plaster; unstable objects overturned; disturbance of trees, poles, and other tall objects
4.1-5.4	VI	Felt by all, many frightened and run outdoors; some heavy furniture may move; falling plaster and chimneys, damage slight
	VII	Everyone runs outdoors; damage to buildings varies depending on quality of construction; noticed by people driving autos
5.4-7.3	VIII	Panel walls thrown out of frames; walls, monuments, chimneys fall; sand and mud ejected; drivers of autos disturbed
	IX	Buildings shifted off foundations, frame structures thrown out of plumb; ground cracked; underground pipes broken
	X	Most masonry and frame structures destroyed*; ground badly cracked, rails bent, landslides; sand and mud shift; water splashes over river banks
7.3 +	XI	Few structures remain standing; bridges destroyed; broad fissures in ground, pipes broken, landslides, rails bent
	XII	Damage total; waves seen on ground surface, lines of sight and level distorted, objects thrown up into the air

- The Mercalli scale is a semi-quantitative linear scale.
- The Richter scale is quantitative logarithmic scale.
- *Buildings constructed with special anti-earthquake techniques, are able to withstand tremors of up to 8.5 on the Richter scale.

Severity	Scale Magnitude	Mercalli
Mild	0-2.9	I-III
Moderate	2.9-4.1	IV-V
Intermediate	4.1-5.4	VI-VII
Severe	5.4-7.3	VIII-X
Catastrophic	7.3 +	XI-XII

[Ohio Seismic Network]

Last update July 19, 2010

Figure 5-29

175 YEARS OF SERVICE 1837–2012

Mailing Address:

ODNR
Division of
Geological Survey
2045 Morse Rd.,
Bldg. C-1
Columbus, OH
43229-6693

Phone: (614) 265-6576
Fax: (614) 447-1918

E-Mail
Location Map

Earthquake Contacts:
24 Hour Earthquake
Reporting Hotline:
1-855-QuakeOH
1-855-(782-5364)

Media Inquiries
Quake Info Center:
Michael C. Hansen
Phone: (740) 548-5979
Fax: (614) 447-1918
E-mail
Web Page

Ohio Seismic Network Stations

Click on station IDs below for station information and data.

[Back to previous page]

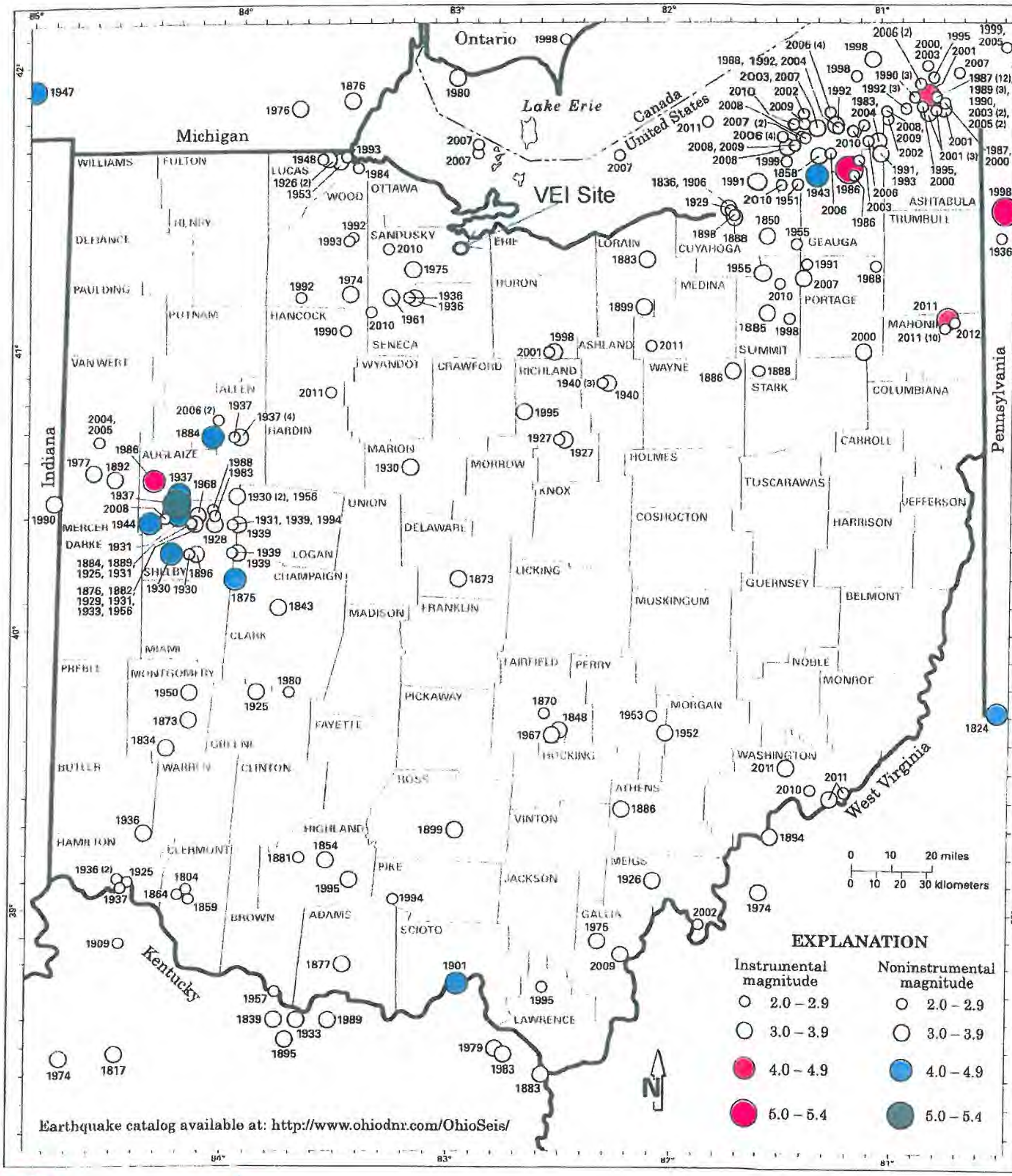
Last update July 20, 2012

OhioSeis
The Ohio Seismic Network

Figure 5-30

STATE OF OHIO • DEPARTMENT OF NATURAL RESOURCES • DIVISION OF GEOLOGICAL SURVEY

EARTHQUAKE EPICENTERS IN OHIO AND ADJACENT AREAS

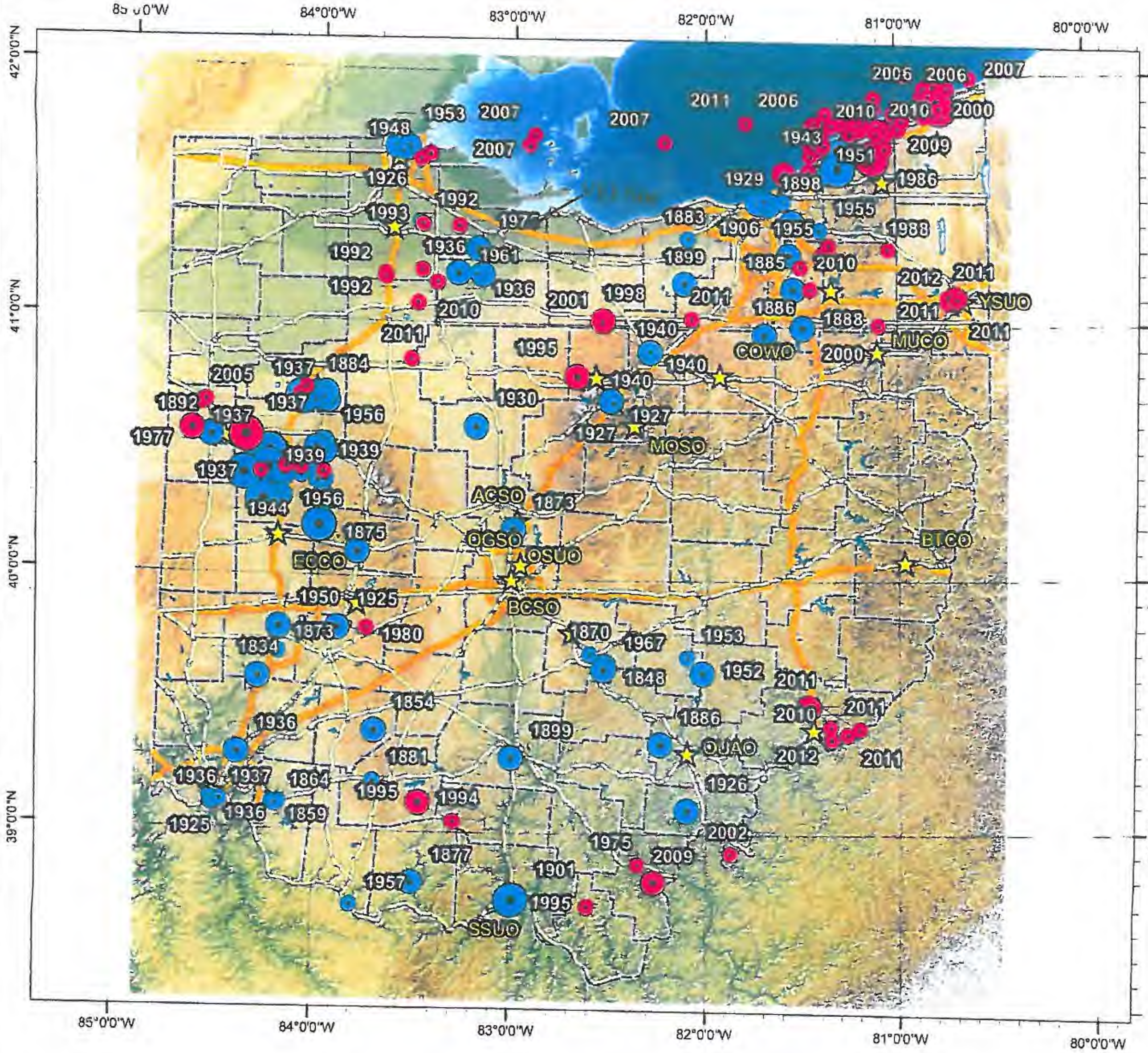


OhioSeis
The Ohio Seismic Network

Recommended citation: Ohio Division of Geological Survey, 2012, Earthquake epicenters in Ohio and adjacent areas—color version: Ohio Department of Natural Resources, Division of Geological Survey Map EG-2, generalized page-size version, 1 p., scale 1:2,000,000.

Figure 5-31

EARTHQUAKE EPICENTERS IN OHIO



EXPLANATION

Instrumental Epicenters	Historical Epicenters
Magnitude, mbLg	Magnitude, Mercalli
2.0 - 3.0	2.0 - 3.0
3.0 - 4.0	3.0 - 4.0
4.0 - 5.0	4.0 - 5.0
5.0 and up	5.0 and up
	Seismic Stations

OhioSeis
The Ohio Seismic Network

0 50 100 150 200 Scale in Kilometers

0 20 40 60 80 100 Scale in Miles

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Recommended bibliographic citation:
2002 (Revised 2008), Earthquake epicenters in Ohio and adjacent areas: Ohio Division of Geological Survey Map EG-2, Internet Mapping Service, http://www.dnr.state.oh.us/website/geosurvey/earthquakes/viewer.htm

-dp-

Figure 5-31A

EARTHQUAKE EPICENTERS IN OHIO

0 8 16 24 32 Scale in Kilometers

0 3 6 9 12 15 Scale in Miles

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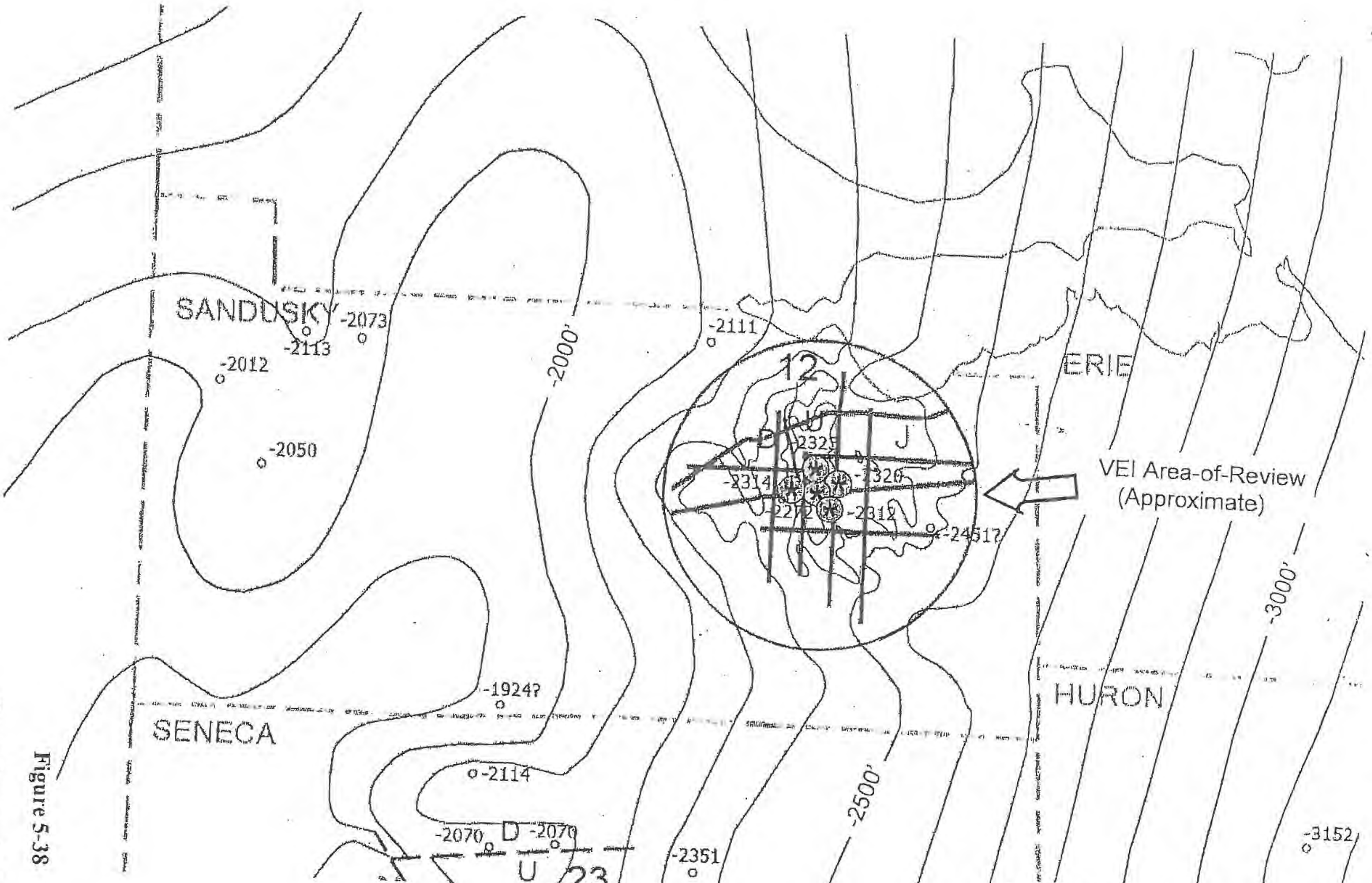
Recommended bibliographic citation:
2002 (Revised 2008), Earthquake epicenters in Ohio and adjacent areas: Ohio Division of Geological Survey Map EG-2, Internet Mapping Service, http://www.dnr.state.oh.us/website/geosurvey/earthquakes/viewer.htm

-dp-

Figure 5-32



Precambrian Structure Map

(Contour labels added by Texas World)

Figure 5-38

From Baranoski, 2002

SEISMIC REFLECTION INVESTIGATION

for

CHEMICAL WASTE MANAGEMENT SITE

Vickery, Ohio

February 1991

Weston Geophysical
CORPORATION

EXECUTIVE SUMMARY

As agreed to with the State of Ohio Environmental Protection Agency (OEPA), a seismic reflection program was undertaken within a five mile radius of Chemical Waste Management's (CWM) Vickery well site in northwestern Ohio. The results of this program of studies, including responses to OEPA comments on a preliminary report, are reported herein.

Results of the agreed upon seismic reflection survey, which constitutes extensive coverage within a five mile radius of the CWM Vickery site, are presented in the form of seismic reflection time profiles (previously submitted) and time and depth structure, and time and depth isopach maps of the identified formations (Appendix A). The maps are drawn on the prominent reflection horizons evident in the stratigraphic section from the Precambrian (570 my) basement unconformity through the Middle Ordovician (458 my) Trenton Limestone. Sedimentary rock units within this section, comprising the injection interval (Mt. Simon), containment interval (Rome, Conasauga, Kerbel, Knox), and the lower portion of the confining interval (Wells Creek, Black River, Trenton), represent the most distinct reflection horizons on the seismic records. The integrity of these rock units is of primary importance in assessing the potential for vertical migration of injected wastes and potential for triggering earthquakes.

Overall, the 59 miles of seismic reflection data, obtained within a five mile radius of the CWM Vickery site, are consistent with the gently southeastward dipping Precambrian unconformable surface overlain by relatively uniform, Early Paleozoic sedimentary units. Superimposed on the regional southeastward dipping surface, a low-relief anticline trends north-south beneath the Vickery site. Time structure and isochron and depth converted structural contour and isopach maps of the Precambrian surface and the Mt. Simon, Rome, and Trenton units, indicate localized sediment thinning and thickening, predominantly within the Mt. Simon, due to nondeposition and/or erosion and filling over paleotopographic relief. Slight arching of the interpreted formations suggests minor intermittent uplift.

Based on analysis and interpretation of the seismic reflection data and the subsequent Line 7 segment produced by data processing using various enhancement techniques, and in the context of local and regional geological, geophysical and seismological information, the origin of the anticlinal feature beneath the CWM Vickery site is related to minor episodic crustal adjustments in the 300 million year interval from Late Precambrian (560mya) to Middle Paleozoic (280mya). The low-gradient relief (120 feet) and lack of evidence for significant brittle deformation, is consistent with a geological environment which fulfills the requirements for "no migration" of wastes through identifiable fractures or faults. Also evidence of the potential to trigger seismicity of any significance is absent.

Attachment C

I. Proposed Well Diagram

II. Proposed Casing and Cementing Programs

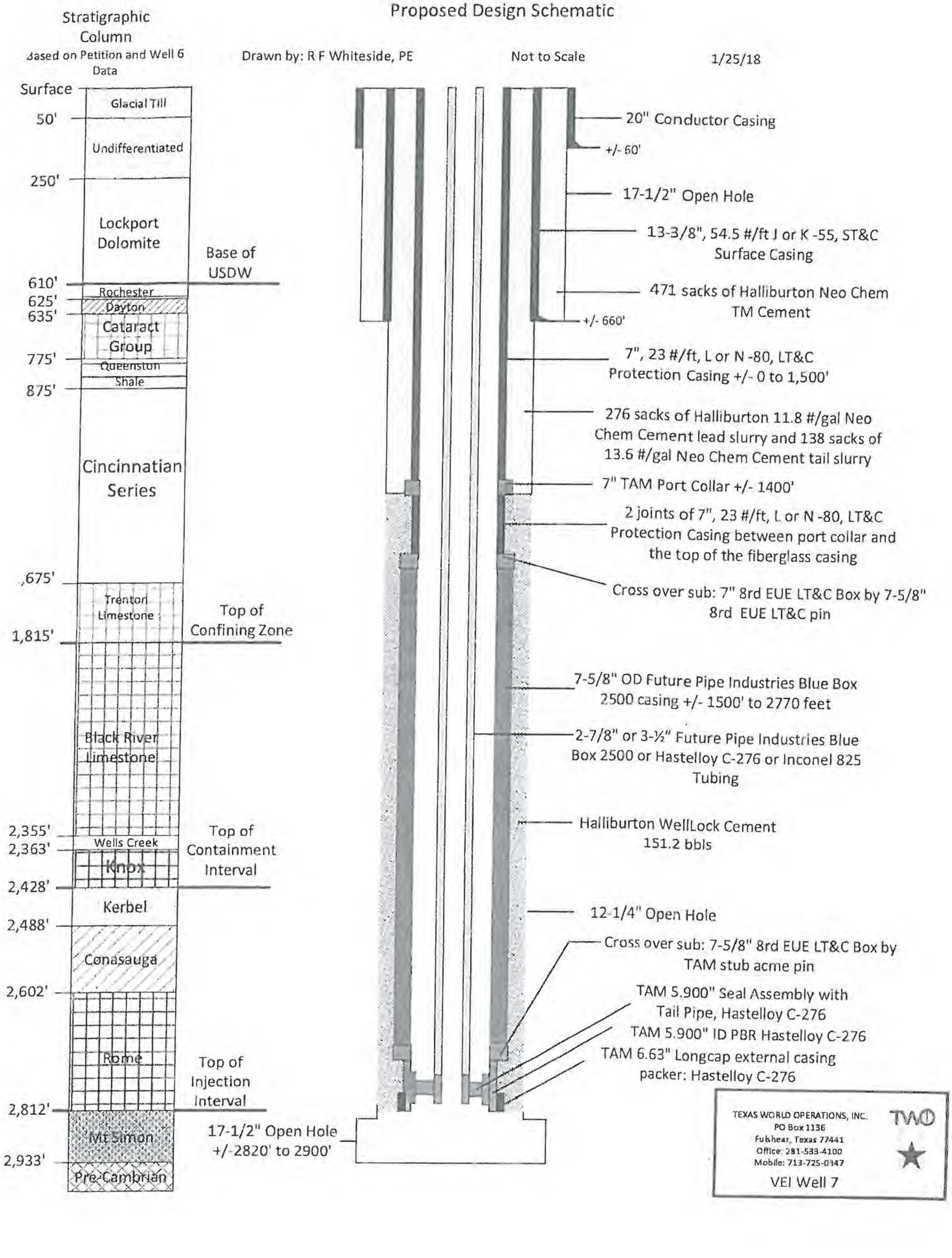
III. Proposed Well Completion

Attachment C

I. Proposed Well Diagram

Drilling Program: Figure 1

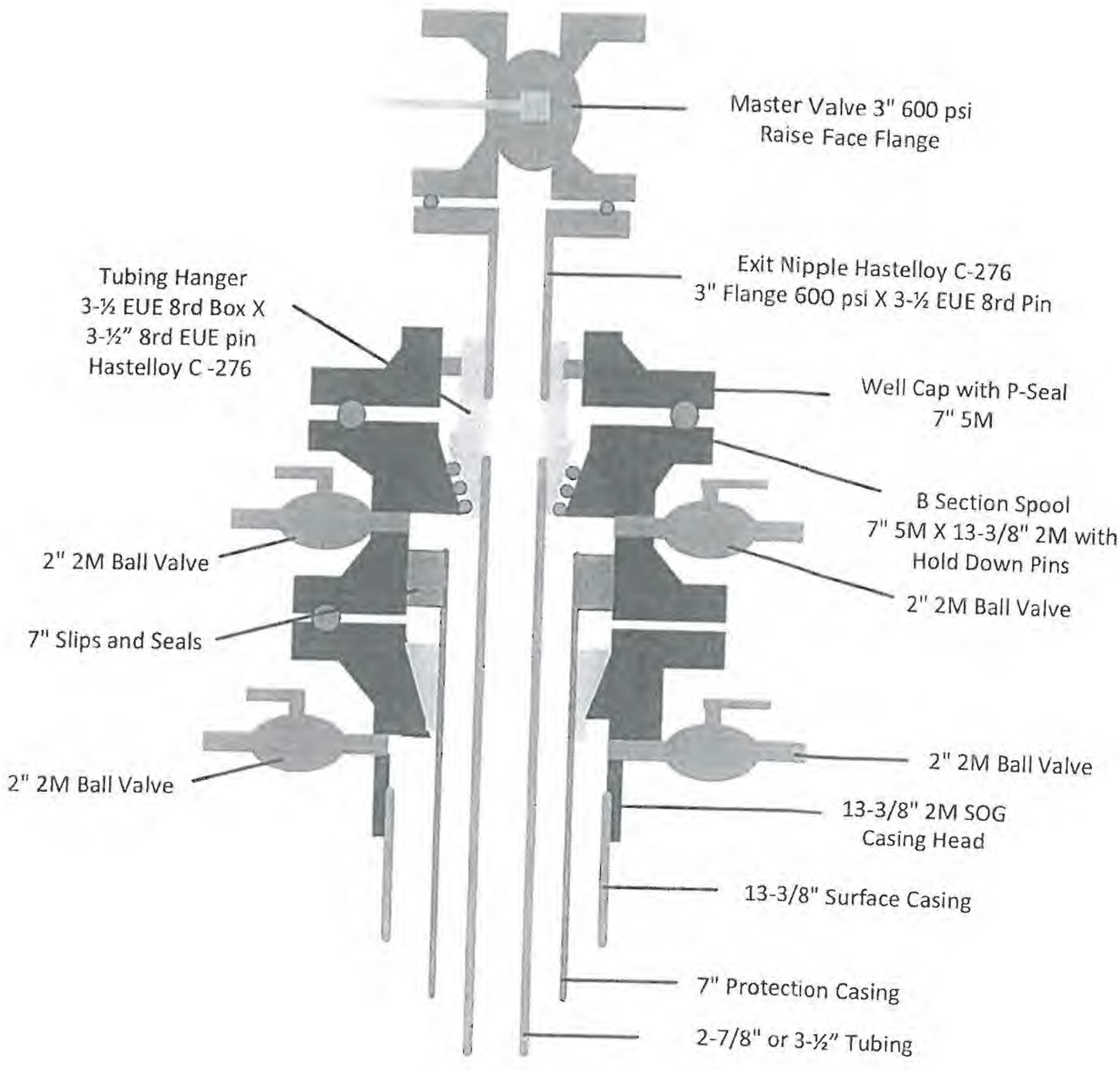
VEI Plant Well 7
Proposed Design Schematic



Drilling Program: Figure 3

VEI Typical Wellhead
Plant Well #7 & #8

Drawn By: R F Whiteside, PE | Not to Scale | 1/25/18



TEXAS WORLD OPERATIONS, INC.
PO Box 1136
Fulshear, Texas 77441
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Attachment C

II. Proposed Casing and Cementing Programs

Drilling Program Plant Well #7

INTRODUCTION

The Vickery Plant Well #7 design incorporates external mechanical sealing between the formation and casing at the injection interval interface. The design addresses galvanic corrosion of the casing by isolating the dissimilar metals of construction by a long section of fiberglass casing. The large open hole size relative to the outside diameter of casing coupled with the centralizer design will ensure excellent cement emplacement by reducing the probability of channeling. All the casing materials of construction expected to have a useful life of more than 40 years.

INJECTION WELL CONSTRUCTION

1. Total depth of the proposed well is +/-2,900 feet.

2. Casing Program

   The casing and tubing selections are based on American Petroleum Institute (API Bulletins 5C2 and 5C3) standards, compatibility tests, historical materials performance, discussions with vendors, past performance records and materials brochures were also considered when selecting the materials to be used in construction of the proposed injection wells. Historical performance with similar injectate streams suggests these tubulars will be resistant to any corrosive effects due to contact with the injectate stream components. The casings to be used in the construction of the well are designed for the life expectancy of the well. The casings proposed for the injection well are rated to have sufficient structural strength for the design life of the well including the maximum pressures and tensile stress which may be experienced at any point along the length of casing or tubing.

   A. Materials and Specifications

Conductor Casing, planned depth = surface to +/- 60 feet

20-inch, 94.0 lb./ft, H-40, Welded end Casing Specifications	
Wall	0.438 inches
I.D.	19.124 inches
Drift	18.936 inches

Coupling O.D.	Not applicable
Collapse	520 psi
Burst	2,110 psi
Pipe Body Strength	1,480,000 lbs.
Joint Strength	Not applicable
Capacity	0.3538 bbls/ft

Surface Casing, planned depth = surface to +/- 660 feet

13-3/8-inch, 54.50 lb./ft, J-55, Buttress or STC Casing Specifications	
Wall	0.380 inches
I.D.	12.615 inches
Drift	12.459 inches
Coupling O.D.	14.375 inches
Collapse	1,130 psi
Burst	2,730 psi
Pipe Body Strength	853,000 lbs.
Joint Strength	1,038,000 Buttress 547,000 ST&C
Capacity	0.1545 bbls/ft

Protection Casing, planned depth = surface to +/- 1,500 feet

7-inch, 23 lb./ft, N-80, LTC Casing Specifications	
Wall	0.317 inches
I.D.	6.366 inches
Drift	6.241 inches
Coupling O.D.	7.656 inches
Collapse	3,270 psi
Burst	4,360 psi
Pipe Body Strength	366,000 lbs.
Joint Strength	313,000 lbs.
Capacity	0.0393 bbls/ft

Protection Casing, planned depth = surface to +/- 1,500 to 2770 feet

Future Pipe Industries 7-5/8-inch, Blue Box 2500-C, EUE 8rd Casing Specifications	
Wall	0.7075 inches
I.D.	6.21 inches
Drift	6.11 inches
Coupling O.D.	7.725 inches
Collapse	2,900 psi
Burst	2,000 psi
Axial Tensile Rating	83,500 lbs.
Tensile Strength, Hoop	31,300 psi
Joint Strength	83,500 lbs.
Capacity	0.0390 bbls/ft

Protection Casing, planned depth = surface to +/- 2,770 to 2800 feet

TAM International 6-5/8-inch, Schedule 80, Hastelloy C-276 PBR Specifications	
Wall	0.432 inches
I.D.	Honed to: 5.900 inches ID
Drift	5.900 inches
Coupling O.D.	7.725 inches
Collapse	10,950 psi
Burst	14,260 psi
Axial Tensile Rating	Exceeds 7" 23 lb./ft
Tensile Strength, Hoop	Exceeds 7" 23 lb./ft
Joint Strength	Exceeds 7" 23 lb./ft
Capacity	0.0390 bbls/ft

Injection Tubing, planned depth = surface to +/- 2,800 feet

2-7/8-inch, Hastelloy C-276 or Inconel-825 tubing Specifications Weakest Tubing Future Pipe Industries – 2-7/8 Blue Box 2500	
Wall	0.217 inches
I.D.	2.47 inches
Drift	2.47 inches
Coupling O.D.	4.06 inches
Collapse	2,900 psi
Burst	2,500 psi
Pipe Body Strength	30,000 lbs.
Joint Strength	22,500 lbs.
Capacity	0.00579 bbls/ft
Notes: VEI may elect to use 3-1/2" FRP, Hastelloy or Inconel as an alternative	

B. The casing strings specified in the permit application are designed for worst case or maximum possible load which could reasonably occur during the drilling, cementing, operation or testing of the well. The design process evaluated the collapse, internal yield (burst) and yield strength (tension) for each casing string. The design includes safety factors to adjust for any damage or wear during the drilling operations or workovers performed inside the casings.

All design parameters used are based on and referenced from the following two publications from the American Petroleum Institute (API).

1) API Bulletin 5C2, 21st edition, October 1999; Performance Properties of Casing, Tubing and Drill Pipe.
2) API Bulletin 5C3, 6th edition, November 1, 1994; Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties.

The most common range of design safety factors and assumed conditions, as defined by API, are given below.

Collapse: 1.0 to 1.125 based on API minimum collapse pressures. The string is assumed to be empty and with either mud, salt water or actual area pressure (formation pressure) applied to the annulus.

Internal Yield (burst): 1.0 to 1.33 based on API minimum yield values. A column at formation pressure is generally assumed to be exerted on all depths within the casing. Casing strings are often designed to withstand pressures equal to the estimated formation breakdown (fracture) pressure at the respective casing shoe, from blowout considerations and /or the pressures applied at the casing shoe by the maximum required casing pressure test.

Tension: 1.6 to 2.0 based on API minimum joint strength, with string freely hanging in air (no buoyancy).

The following minimum safety factors are required for each casing string in the proposed injection well.

Safety Factors	
Collapse:	1.125
Internal Yield (burst):	1.330
Tension:	2.000

The maximum collapse pressure will most likely occur during cementing or backflowing of the well. The maximum internal yield pressure (burst) will occur during internal pressure tests on each casing string to verify mechanical integrity. The maximum tension will occur while landing the casing string in the wellhead assembly.

The pressure gradient used in the burst and collapse calculations is the calculated cement gradient for the Mt. Simon (injection zone) which is the casing shoe point. The gradient is valid based on the API calculation specifications. The 0.706939 psi/ft gradient is equivalent to a column of 13.6 lbs./gal cement from 2800 feet to surface. This gradient is beyond normal conditions expected during the drilling, completion, testing and operation of the proposed injection wells.

Definitions and Formulas:

P_C: *minimum collapse pressure, psi*
P_I: *minimum burst pressure, psi*
L_J: *minimum joint strength, lbs*
D_C: *collapse, maximum setting depth, feet*
D_I: *burst, maximum setting depth, feet*
D_T: *tension, maximum setting depth, feet*

G: *gradient, psi/ft*
S_F: *safety factor*
w: *pipe weight, lb/ft*
lb/ft: *pounds per foot*
psi: *pounds per square inch*

$D_C = (P_C / S_F) \div G$

$D_I = (P_I / S_F) \div G$

$D_T = (L_J / S_F) \div w$

Note: The values for P_C, P_I and L_J are from published API and Future Pipe Industries tables for specific casing size, steel grade and thread type. The numbers are calculated using formulas in the previously referenced API bulletins.

Calculations:

<u>13-3/8" surface casing, 54.5 lb./ft, J or K 55, STC thread connections</u>

Design setting depth = +/- 660 feet
P_C (collapse) = 1,130 psi
P_I (burst) = 2730 psi
L_J (tension) = 514,000 lbs.
G = 0.706939 psi/ft

$D_C = (P_C / S_F) \div G$: (1130 psi/1.125) ÷ 0.706939 psi/ft = 1,420.837 feet
$D_I = (P_I / S_F) \div G$: (2730 psi/1.330) ÷ 0.706939 psi/ft = 2,903.549 feet
$D_T = (L_J / S_F) \div w$: (514,000 lbs /2.000) ÷ 36 lb./ft = 4,715.896 feet

All calculated design depths are within the maximum calculated safety depths.

<u>7" protection casing, 23 lb./ft, L or N-80, LTC thread connections</u>

Design setting depth = +/- 1500 feet
P_C (collapse) = 3,830 psi
P_I (burst) = 6,340 psi
L_J (tension) = 442,000 lbs.
G = 0.706939 psi/ft

$D_C = (P_C / S_F) \div G$: (3,830 psi/1.125) ÷ 0.706939 psi/ft = 4,853.48 feet
$D_I = (P_I / S_F) \div G$: (6,340 psi/1.330) ÷ 0.706939 psi/ft = 11,327.49 feet
$D_T = (L_J / S_F) \div w$: (442,000 lbs /2.000) ÷ 23 lb./ft = 4,055.05 feet

All calculated design depths are within the maximum calculated safety depths.

7-5/8" Fiberglass protection casing, 12.6 lb./ft, Blue Box 2500, LTC thread connections

Design setting depth = +/- 1500 to +/- 2800 feet
Future Pipe has a 4:1 Safety Factor built into the performance numbers, therefore no additional safety factors are necessary.
P_C (collapse) = 2,500 psi
P_I (burst) = 2,500 psi
L_J (tension) = 30,000 lbs.
G = 0.706939 psi/ft

$D_C = (P_C / S_F) \div G$: (2,500 psi/1) ÷ 0.706939 psi/ft = 3,960.739 feet
$D_I = (P_I / S_F) \div G$: (2,500 psi/1) ÷ 0.706939 psi/ft = 3,960.739 feet
$D_T = (L_J / S_F) \div w$: (30,000 lbs. /1) ÷ 12.6 lb./ft = 2,380.952 feet

All calculated design depths are within the maximum calculated safety depths.

2-7/8" Fiberglass injection tubing, 2.0 lb/ft, Blue Box 2500, 8rd EUE thread connections

Design setting depth = +/- 2,800 feet
P_C (collapse) = 2,500 psi
P_I (burst) = 2,500 psi
L_J (tension) = 30,000 lbs.
G = 0.883493 psi/ft (gradient for 11.5 lb/gal fluid + 800 psi surface injection pressure)

$D_C = (P_C / S_F) \div G$: (2,500 psi/1) ÷ 0.4571 psi/ft = 3,169.237 feet
$D_I = (P_I / S_F) \div G$: (2,500 psi/1) ÷ 0.4571 psi/ft = 3,169.237 feet
$D_T = (L_J / S_F) \div w$: (30,000 lbs. /1) ÷ 2.0 lb/ft = 15,000 feet

All calculated design depths are within the maximum calculated safety depths.

C. Inspection requirements for carbon steel tubulars:

i. All tubulars must be manufactured to the current edition of API 5CT.
ii. All API threads must be manufactured to the current edition of API 5B.
iii. AMALOG IV or equivalent full-length electromagnetic inspection.

7. Centralizers, scratchers, etc

13-3/8" Surface Casing

Two centralizers on float joint. Bowspring centralizer on next 4 casing collars, then every 2nd joint except a centralizer will be on the top two collars. Total of 16 – 20 centralizers.

Protection Casing

Two centralizers on float joint. The fiberglass casing will have centralizers molded onto each joint. Bowspring used on the 7-inch steel casing. Bowspring centralizers will be run above and below the multiple-stage cementing and one every 2nd joint of casing, with two centralizers on the top joint. Total of 80 - 90 centralizers

8. Cementing

The regulations require that the cement be emplaced from the casing setting depth to surface for both the surface and protection casings.. Adequate cement bond to the pipe and the formation must also be demonstrated by running a cement bond tool. In this program, certain cement vendor trade names are used. Final cement slurries will use equal and equivalent products based on final vendor recommendations.

Conductor: Cemented with Redi-mix to surface if drilled or augered.

Surface Casing: (+/- 660 feet to surface)

Spacer
6% Gel Spacer
20 lbs./bbl. National Premium Gold — 30 bbl.

Lead Slurry
NeoCem TM
5.36 Gal/sk Fresh Water

Fluid Weight:	15.8 lbs./gal
Slurry Yield:	1.236 ft3/sack
Total Mixing Fluid:	5.36 gal/sk
Calculated Volume:	103.7 bbl
Proposed Volume:	103.7 bbl
Top of Fluid:	0 ft
Calculated Fill:	660 ft
Calculated Sack:	470.88 sack
Proposed Sack:	471 sack
Excess:	30% over caliper volume

Note: Volumes above based on 100% excess over gauge hole volumes. Actual cement volumes will be based on open-hole caliper volume + 30% excess. More excess may be added based on hole conditions. Cement blends may be modified to suit actual well conditions.

Protection Casing: First Stage (+/- 2800 feet to +/- 1400 feet):

Note: Volumes above based on 10% excess over gauge hole volumes in drilled bore hole. Actual cement volumes will be based on open-hole caliper volume plus a minimum of 10% excess. Cement blends may be modified to suit

Stage 1
Spacer
6% Gel Spacer
20 lbs./bbl. National Premium Gold 30 bbl.

Lead Slurry
SBM CMT WellLock PKG

Fluid Weight:	11.2 lbs./gal
Calculated Volume:	151.2 bbl
Top of Fluid:	1400 ft
Calculated Fill:	1400 ft
Excess:	10% over caliper volume

Protection Casing: Second Stage (+/- 1400 feet to +/- 0 feet):

Spacer
6% Gel Spacer
20 lbs./bbl. National Premium Gold 30 bbl.

Lead Slurry
NeoCem TM
12.79 Gal/sk Fresh Water

Fluid Weight:	11.8 lbs./gal
Slurry Yield:	2.224 ft3/sack
Total Mixing Fluid:	12.79 gal/sk
Calculated Volume:	109 bbl
Proposed Volume:	109 bbl
Top of Fluid:	0 ft
Calculated Fill:	1000 ft
Calculated Sack:	275.06 sack
Proposed Sack:	276 sack
Excess:	10% over caliper volume

Tail Slurry
NeoCem TM
9.34 Gal/sk Fresh Water

Fluid Weight:	13.6 lbs./gal
Slurry Yield:	1.762 ft3/sack
Total Mixing Fluid:	9.34 gal/sk
Calculated Volume:	43.2 bbl
Proposed Volume:	43.2 bbl
Top of Fluid:	1000 ft

Calculated Fill:	400 ft
Calculated Sack:	137.65 sack
Proposed Sack:	138 sack
Excess:	10% over caliper volume

Note: Volumes above based on 10% excess over gauge hole volumes. Actual cement volumes will be based on open-hole caliper volume + 10% excess. More excess may be added based on hole conditions. Cement blends may be modified to suit actual well conditions.

Attachment C

III. Proposed Well Completion

Appendix I

TAM International

Completion and Running Procedure

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS

OUTER CASING

Component Descriptio	Part #	OD (in)	ID (in)	Length (ft)	Comments	Material		
7.00" Port Collar	700-PC-01	8.25	6.18	2	7.00" LTC Box x Pin	L80		
7.00 " LONGCAP	700-LC-01	8.06	6.18	12	7.00" LTC Box x Pin	L80		
Crossover A		8.25	8.00	1	7" LTC Box x 7" Fiberglass Pin	L80		
7.00" Fiberglass Casing		TBA	TBA	1,300		FG		
Crossover B		8.25	6.18		7.00" FG Box x 8.452 SA Box	C276		
5.90" ID " PBR		8.25	5.90	20	5.90" honed ID, ????" SA Pin x	C276		
Crossover C		8.25	5.90	1	????? SA box x Box	C276		
6 5/8"" LONGCAP	663-LC-01 - H	8.06	5.90	12	TBA SA Pin x Pin	C276	HONED	with viton elastomer
Re-Entry Guide	TW-0794-32	8.25	6.18	1	????? SA Box x re-entry profile	C276	TOGETHER	
	5							

INNER STRING

Component Descriptio	Part #	OD (in)	ID (in)	Length (ft)	Comments	
Wellhead Landing Joint		3.50	2.94	20	3 1/2" SA pin down	C276
Crossover Coupling		4.50	3.00	1	3 1/2" SA Box x 3 1/2" FG Pin	C276
Fiberglass Tubing		4.75	2.94	2,700		FG
Fiberglass No-Go Joint		6.00	3.00	30	Built on FG Joint	FG
Seal Body with 5.90 seals		5.90	3.00	6	3 1/2" FG Box x 3 1/2" FG Box	C276
Mule Shoe Extension		4.50	3.00	25	Box cut off - mule shoe - pin up	FG

Service String - 7.00" Combo Tool for operating 7.00" PC versus drill out oc DV tool option

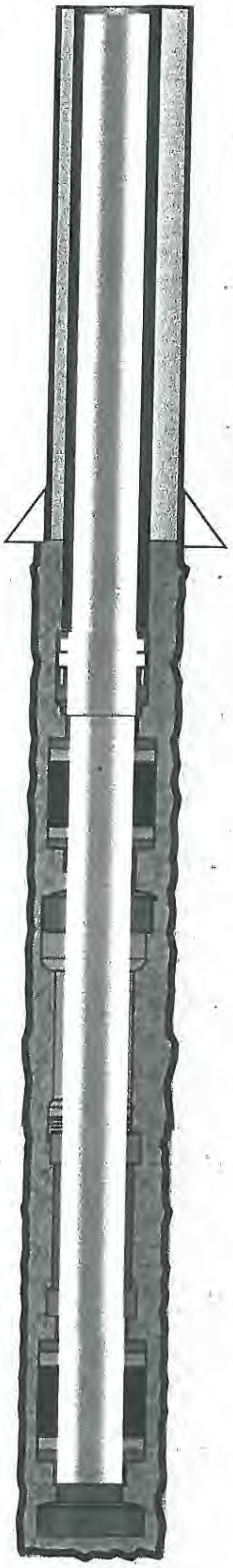
Crossover Sub	
7" Combo Tool	700-CT-05
4 3/4" Choke Sub	475-CH-01
Crossover Sub	
Tubing	
Crossover Sub	
5.90" Service Seal Assembly	
Ball Catcher Sub	
Tail pipe	

Workstring connection by 3 1/2" IF pin
7" Combo Tool 29 ppf cups 3 1/2" IF box by pin
Choke Sub 3 1/2" IF Box by Pin
3 1/2" IF by workstring pin

Workstring Connection to 5.90" Seal Assembly
5.90" Service seal assembly

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS



7.00" 23 ppf., N80 Casing to surface

1. Pick up assembly and run in the hole with packers and port colarr spaced out as required.

2. Break circulation to clean up wellbore before cementing

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS

7.00" 23 ppf., N80 Casing to surface

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1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

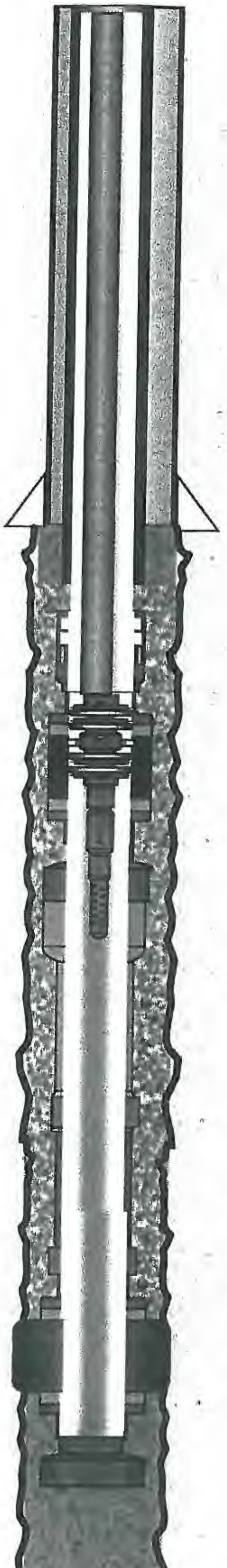
6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

3. Run inner string with seal assembly, sting into lower packer
4. Break circulation, mix & pump calculated volumecement
5. Drop ball behind cement, land in choke sub
6. Increase pressure, inflate Longcap
7. Shear out choke, pooh

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS



7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

8. Pick up 7" Combo Tool position across Longcap
9. Drop ball for choke sub, test combo tool
10. Inflate Longcap
11. Pick up locate Port Collar

TWO- Vickery 7.00 IN casing assembly, B rev

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS

7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

12. Slack off open Port Collar
13. Circulate cement out and condition hole
14. Perform 2nd stage cement job

TWO- Vickery 7.00 IN casing assembly, B rev

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS

7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

15. Close Port Collar, test Port Collar

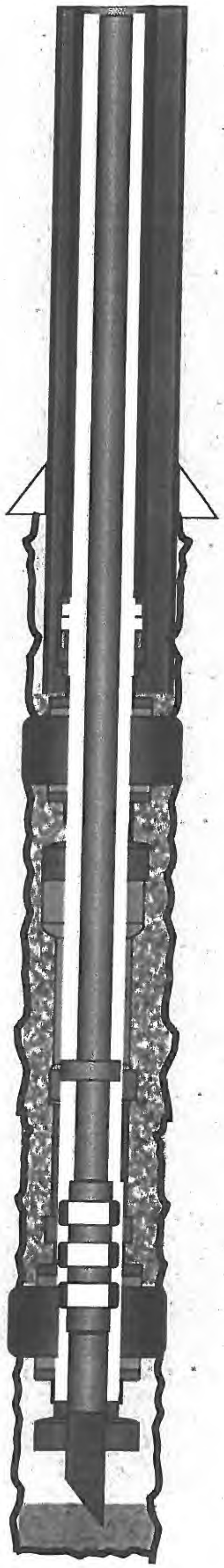
16. Reverse out

17. Pooh

TWO- Vickery 7.00 IN casing assembly, B rev

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS



18. Run seal assembly and tubing

7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

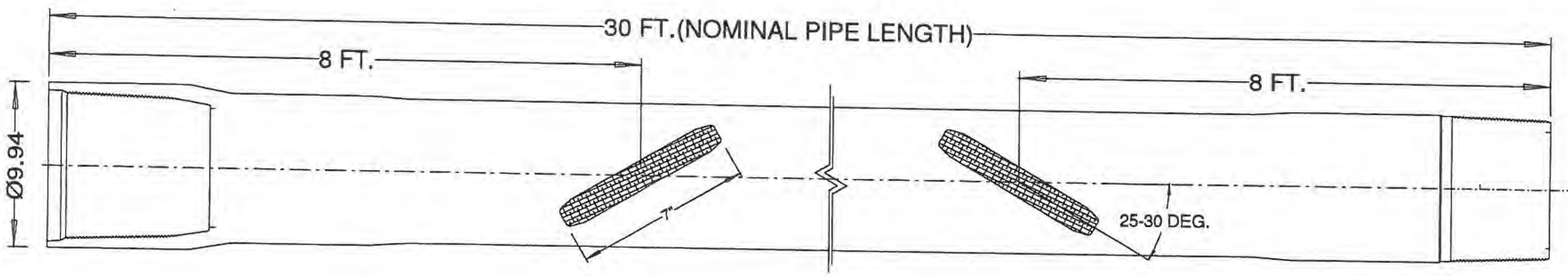
BTM TAMCAP 2800 FT.

TWO- Vickery 7.00 IN casing assembly, B rev

Appendix II

Future Pipe Industries

External Casing Centralizer



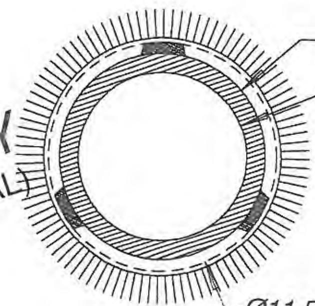
7-5/8 BB 2500

BOX OD=9.94
BODY OD=7.56

7-5/8" CASING LONG THREAD
(FPI 7-5/8 BB 2500)

L4=4.125
E1=7.524
M=0.709
A=3.5 THREAD TURN
8-RD, 3/4 TPF

CENTRALIZER OD=11.50
(CLEARANCE OD 11-3/4)
2 SETS OF 3 BLADES
8 FT FROM THE END



PRELIMINARY
(HOLD FOR APPROVAL)

PREPARE FOR T.W.O. (7-5/8 BB 2500 WITH CENTRALIZER)
QUOTE 62.N.01.18.07

*DO NOT SCALE

Part Number:			
UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES		MM/DD/YY	FUTURE PIPE INDUSTRIES
	Drawn By DT	01/09/18	
	Checked By		CENTRALIZER 7-5/8 BB 2500
Material Type	Approved By		
	Revision 1		
Finish Type or Method	Revision 2		Drwg Number: 62/PRODUCT/7-5/8 BB 2500 CENT.
	Revision 3		Revision

Appendix III

Materials Specifications

FPi
FUTURE PIPE INDUSTRIES

Technical Data Sheet
(Single Product Format)

2-7/8" BLUE BOX 2500 8Rd
FIBREGLASS CASING AND TUBING
AROMATIC AMINE CURED EPOXY RESIN

V17.25 (Oct-04-2017)

DIMENSIONAL SPECIFICATIONS

Nom. Size (in.)	Rating (psi)	Nom. I.D. (in.)	Nom. I.D. (mm)	Nom. O.D. (in.)	Nom. O.D. (mm)	Nom Box O.D. (IJ) (in.)	Nom Box O.D. (IJ) (mm)	Drift Diameter (in.)	Drift Diameter (mm)
2-7/8	2500	2.47	62.6	3.04	77.2	4.06	103.2	2.37	60.3

Tolerance on Nom. Box O.D. is +/- 0.10" up to 9-5/8"; +/- 0.15" above 9-5/8"

THREAD DETAILS

Nom. Size (in.)	Thread	Joint Short Code	Connection Type	FPi Connection Code	Ends
2-7/8	2-7/8	AW	2-7/8" 8Rd EUE Long IJ	0278-EUE-LONG-A8	IJ

Nom. Size (in.)		Pitch (E1) (in.)	Pitch (E1) (mm)	L4 (in.)	L4 (mm)	D4 (in.)	D4 (mm)	Pin Upset O.D. (in.)	Pin Upset O.D. (mm)
2-7/8		3.008	76.4	2.875	73.0	3.094	78.6	3.194	81.1

Thread lengths may exceed API L4.

Rd = Round thread per inch, EUE = External-Upset Ends, Csg = Casing, IJ = Integral Joint, TC = Threaded & Coupled

PERFORMANCE AND RATINGS -60F (-50c) to +150F (65c)

Nom. Size (in.)		Design Pressure (psi)	Design Pressure (bar)	Factory Hydrotest Pressure (psi)	Factory Hydrotest Pressure (bar)	Max. Field Test Pressure (psi)	Max. Field Test Pressure (bar)	Collapse Rating (psi)	Collapse Rating (bar)
2-7/8		2500	172.4	3250	224.1	2500	172.4	2900	200.0

Factory and field test pressure may be reduced for certain casing applications and for some turndown box products.

Nom. Size (in.)		Min. Bend Radius (ft)	Min. Bend Radius (m)	Axial Tensile Rating (uniaxial) (lbs)	Axial Tensile Rating (uniaxial) (kN)	Axial Tensile Rating (biaxial) (lbs)	Axial Tensile Rating (biaxial) (kN)	Nom. Wgt (lb/ft)	Nom. Wgt (kg/m)
2-7/8		150	46	22,500	5.1	22,500	5.1	2.0	3.0

Standard de-rating factors: 203F (95c), 0.88; 212F (100c), 0.81; 230F (110c), 0.66; 250F (121c), 0.50

MECHANICAL AND PHYSICAL PROPERTIES

Pipe Body Properties	<= 10-3/4	>= 11-3/4		<= 10-3/4	>= 11-3/4	
Tensile Strength, Hoop	31,300	40,000	psi	216	276	MPa
Tensile Strength, Axial (biaxial loading)	30,000	20,000	psi	207	138	MPa
Tensile Strength, Axial (uniaxial loading)	30,000	9,400	psi	207	65	MPa
Axial Modulus	2.5	1.5	10^6 psi	17.2	10	GPa
Specific Gravity	1.93	1.93	---	1.93	1.93	---
Density	0.07	0.07	lb/in3	1.94	1.94	g/cm3
Thermal Conductivity	2.4	2.4	Btu-in./(hr-ft2-F)	0.0035	0.0035	W-cm/(cm2-C)
Thermal Expansion Coefficient (Linear)	0.000011	0.000012	in./in./F	0.000020	0.000022	cm/cm/C
Flow Factor (Hazen Williams)	150	150	---	150	150	---

FUTURE PIPE INDUSTRIES

Technical Data Sheet
(Single Product Format)

3-1/2" BLUE BOX 2500 8Rd
FIBREGLASS CASING AND TUBING
AROMATIC AMINE CURED EPOXY RESIN

V17.25 (Oct-04-2017)

DIMENSIONAL SPECIFICATIONS

Nom. Size (in.)	Rating (psi)	Nom. I.D. (in.)	Nom. I.D. (mm)	Nom. O.D. (in.)	Nom. O.D. (mm)	Nom Box O.D. (IJ) (in.)	Nom Box O.D. (IJ) (mm)	Drift Diameter (in.)	Drift Diameter (mm)
3-1/2	2500	3.00	76.1	3.68	93.4	4.97	126.3	2.90	73.7

Tolerance on Nom. Box O.D. is +/- 0.10" up to 9-5/8"; +/- 0.15" above 9-5/8"

THREAD DETAILS

Nom. Size (in.)	Thread	Joint Short Code	Connection Type	FPI Connection Code	Ends
3-1/2	3-1/2	BH	3-1/2" 8Rd EUE Long IJ	0312-EUE-LONG-A8	IJ

Nom. Size (in.)		Pitch (E1) (in.)	Pitch (E1) (mm)	L4 (in.)	L4 (mm)	D4 (in.)	D4 (mm)	Pin Upset O.D. (in.)	Pin Upset O.D. (mm)
3-1/2		3.664	93.1	3.125	79.4	3.750	95.3	3.850	97.8

Thread lengths may exceed API L4.

Rd = Round thread per inch, EUE = External-Upset Ends, Csg = Casing, IJ = Integral Joint, TC = Threaded & Coupled

PERFORMANCE AND RATINGS -60F (-50c) to +150F (65c)

Nom. Size (in.)		Design Pressure (psi)	Design Pressure (bar)	Factory Hydrotest Pressure (psi)	Factory Hydrotest Pressure (bar)	Max. Field Test Pressure (psi)	Max. Field Test Pressure (bar)	Collapse Rating (psi)	Collapse Rating (bar)
3-1/2		2500	172.4	3250	224.1	2500	172.4	2900	200.0

Factory and field test pressure may be reduced for certain casing applications and for some turndown box products.

Nom. Size (in.)		Min. Bend Radius (ft)	Min. Bend Radius (m)	Axial Tensile Rating (uniaxial) (lbs)	Axial Tensile Rating (uniaxial) (kN)	Axial Tensile Rating (biaxial) (lbs)	Axial Tensile Rating (biaxial) (kN)	Nom. Wgt (lb/ft)	Nom. Wgt (kg/m)
3-1/2		182	55	30,500	6.9	30,500	6.9	3.0	4.4

Standard de-rating factors: 203F (95c), 0.88; 212F (100c), 0.81; 230F (110c), 0.66; 250F (121c), 0.50

MECHANICAL AND PHYSICAL PROPERTIES

Pipe Body Properties	<= 10-3/4	>= 11-3/4		<= 10-3/4	>= 11-3/4	
Tensile Strength, Hoop	31,300	40,000	psi	216	276	MPa
Tensile Strength, Axial (biaxial loading)	30,000	20,000	psi	207	138	MPa
Tensile Strength, Axial (uniaxial loading)	30,000	9,400	psi	207	65	MPa
Axial Modulus	2.5	1.5	10^6 psi	17.2	10	GPa
Specific Gravity	1.93	1.93	---	1.93	1.93	---
Density	0.07	0.07	lb/in3	1.94	1.94	g/cm3
Thermal Conductivity	2.4	2.4	Btu-in./(hr-ft2-F)	0.0035	0.0035	W-cm/(cm2-C)
Thermal Expansion Coefficient (Linear)	0.000011	0.000012	in./in./F	0.000020	0.000022	cm/cm/C
Flow Factor (Hazen Williams)	150	150	---	150	150	---

FUTURE PIPE INDUSTRIES

Technical Data Sheet

(Single Product Format)

7-5/8" BLUE BOX 2500 C 8Rd

FIBREGLASS CASING AND TUBING

AROMATIC AMINE CURED EPOXY RESIN

V17.25 (Oct-04-2017)

DIMENSIONAL SPECIFICATIONS

Nom. Size	Rating	Nom. I.D.		Nom. O.D.		Nom Box O.D. (IJ)		Drift Diameter	
(in.)	(psi)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)
7-5/8	2500-C	6.21	157.6	7.56	191.9	9.94	252.5	6.11	155.2

Tolerance on Nom. Box O.D. is +/- 0.10" up to 9-5/8"; +/- 0.15" above 9-5/8"

THREAD DETAILS

Nom. Size (in.)	Thread	Joint Short Code	Connection Type	FPi Connection Code	Ends
7-5/8	7-5/8	GJ	7-5/8" 8Rd CSG Long IJ	0758-CSG-LTC-B8	IJ

Nom. Size		Pitch (E1)		L4		D4		Pin Upset O.D.	
(in.)		(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)
7-5/8		7.524	191.1	4.125	104.8	7.625	193.7	7.725	196.2

Thread lengths may exceed API L4.

Rd = Round thread per inch, EUE = External-Upset Ends, Csg = Casing, IJ = Integral Joint, TC = Threaded & Coupled

PERFORMANCE AND RATINGS -60F (-50c) to +150F (65c)

Nom. Size		Design Pressure		Factory Hydrotest Pressure		Max. Field Test Pressure		Collapse Rating	
(in.)		(psi)	(bar)	(psi)	(bar)	(psi)	(bar)	(psi)	(bar)
7-5/8		2000	137.9	2600	179.3	2000	137.9	2900	200.0

Factory and field test pressure may be reduced for certain casing applications and for some turndown box products.

Nom. Size		Min. Bend Radius		Axial Tensile Rating (uniaxial)		Axial Tensile Rating (biaxial)		Nom. Wgt	
(in.)		(ft)	(m)	(lbs)	(kN)	(lbs)	(kN)	(lb/ft)	(kg/m)
7-5/8		375	114	83,500	18.8	83,500	18.8	12.6	18.7

Standard de-rating factors: 203F (95c), 0.88; 212F (100c), 0.81; 230F (110c), 0.66; 250F (121c), 0.50

MECHANICAL AND PHYSICAL PROPERTIES

Pipe Body Properties	<= 10-3/4	>= 11-3/4		<= 10-3/4	>= 11-3/4	
Tensile Strength, Hoop	31,300	40,000	psi	216	276	MPa
Tensile Strength, Axial (biaxial loading)	30,000	20,000	psi	207	138	MPa
Tensile Strength, Axial (uniaxial loading)	30,000	9,400	psi	207	65	MPa
Axial Modulus	2.5	1.5	10^6 psi	17.2	10	GPa
Specific Gravity	1.93	1.93	---	1.93	1.93	---
Density	0.07	0.07	lb/in3	1.94	1.94	g/cm3
Thermal Conductivity	2.4	2.4	Btu-in./(hr-ft2-F)	0.0035	0.0035	W-cm/(cm2-C)
Thermal Expansion Coefficient (Linear)	0.000011	0.000012	in./in./F	0.000020	0.000022	cm/cm/C
Flow Factor (Hazen Williams)	150	150	---	150	150	---

Chemical Resistance Guide Tables

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Acetic Acid 10%	150	200
Acetic Acid-75%	100	120
Acetic Acid-Glacial	NR	NR
Acetone	NR	120
Acrylic Acid	NR	100
Adipic Acid, Solution	200	200
Air	210	230
Alcohol, Ethyl	150	150
Alcohol, Isopropyl	150	150
Alcohol, Methyl	150	150
Alcohol, Methyl Isobutyl	150	150
Alcohol, Secondary Butyl	150	150
Allyl Chloride	100	100
Aluminum Chloride	200	230
Aluminum Fluoride	100	150
Aluminum Hydroxide	100	150
Aluminum Nitrate	200	230
Aluminum Sulfate	200	230
Alum	200	230
Ammonia Gas-Dry	150	230
Ammonia-Wet	NR	100
Ammonium Carbonate	100	150
Ammonium Chloride	200	230
Ammonium Fluoride-25%	100	150
Ammonium Hydroxide-10%	100	150
Ammonium Hydroxide-28%	NR	100
Ammonium Nitrate	200	230
Ammonium Persulfate	NR	100
Ammonium Phosphate	150	150
Ammonium Sulfate	200	230
Amyl Acetate	NR	100
Amyl Chloride	NR	100
Aniline	NR	100
Barium Carbonate	200	230
Barium Chloride	200	230
Barium Hydroxide-10%	200	230
Barium Sulfate	200	230
Barium Sulfide	200	230

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Benzene	100	150
Benzene Sulfonic Acid	NR	100
Benzoic Acid	NR	100
Borax	200	230
Boric Acid	150	200
Bromic Acid	100	150
Bromine	NR	NR
Butadine	100	100
Butane	100	100
Butyl Acetate	NR	100
Butyl Cellosolve	150	150
Butyric Acid-50%	150	150
Calcium Bisulfite	200	200
Calcium Carbonate	200	230
Calcium Chlorate	200	200
Calcium Chloride	200	230
Calcium Hydroxide-50%	200	200
Calcium Hypochlorite-20%	NR	NR
Calcium Nitrate	200	230
Calcium Sulfate	200	230
Carbon Bisulfide	NR	NR
Carbon Dioxide	200	230
Carbon Tetrachloride	100	150
Carbonic Acid	150	200
Castor Oil	200	200
Chlorine	NR	NR
Clorinated Water 0-3000 Ppm	150	230
Chloroacetic Acid-25%	100	120
Chlorobenzene	100	150
Chloroform	NR	100
Chromic Acid-10%	NR	150
Chromic Fluoride	NR	100
Citric Acid	200	230
Copper Chloride	200	230
Copper Fluoride	200	230
Copper Nitrate	200	230
Copper Sulfate	200	200
Crude Oil-Sour, Sweet	200	230

* Green Box™ chemical grade line pipe and Blue Box® chemical grade tubing and casing Products are offered with Nexus Liner

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Diacetone Alcohol	150	150
Dimethylamine	NR	NR
O-Dichlorobenzene	100	150
Dichloroethylene	NR	100
Diethylene Triamine	NR	NR
Ethyl Acetate	NR	150
Ethyl Cellosolve	NR	100
Ethyl Chloride	NR	100
Ethyl Ether	NR	100
Ethyl Chlorohydrin	NR	NR
Ethyl Diamine	NR	NR
Ethyl Glycol	200	200
Ethylene Oxide	NR	NR
Fatty Acids	200	200
Ferric Chloride	150	230
Ferric Nitrate	200	230
Ferric Sulfate	200	200
Ferrous Chloride	200	230
Ferrous Sulfate	200	200
Fluorosilicic Acid-10%	200	200
Formaldehyde-40%	NR	100
Formic Acid-25%	NR	100
Freon	NR	150
Gas-Natural	200	230
Gasoline-Sour	200	230
Gasoline-Refined, All Grades	150	150
Glucose	200	230
Glycerine	200	230
Glycol, Ethylene	200	200
Glycol, Propylene	200	230
Heptane	150	150
Hexane	NR	100
Hexylene Glycol Alcohol	150	150
Hydraulic Fluid	200	200
Hydrobromic Acid-50%	NR	150
Hydrochloric Acid-35%	100	150
Hydrocyanic Acid-10%	NR	NR
Hydrofluoric Acid	NR	NR
Hydrogen	150	150
Hydrogen Peroxide-10%	NR	150
Hydrogen Peroxide-30%	NR	75
Hydrogen Sulfide	150	200
Hypochlorous Acid-10%	200	200
Jet Fuel	150	200

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Kerosene	200	230
Lactic Acid	150	200
Lauric Acid	200	200
Lead Acetate	200	230
Levulinic Acid-25%	200	200
Magnesium Carbonate	200	230
Magnesium Chloride	200	230
Magnesium Hydroxide	120	200
Magnesium Nitrate	200	230
Magnesium Sulfate	200	230
Maleic Acid	150	150
Mercury	200	230
Methane	200	230
Methyl Ethyl Ketone	NR	100
Methyl Isobutyl Carbitol	NR	100
Methyl Isobutyl Ketone	100	150
Mineral Oils	200	230
Naptha	200	200
Napthalene	150	150
Natural Gas	200	230
Nickel Chloride	200	230
Nickel Nitrate	200	200
Nitric Acid-10%	NR	100
Oil, Sour, Crude	200	230
Oleic Acid	200	200
Oxalic Acid	200	200
Perchloric Acid-70%	NR	100
Phenol-5%	NR	150
Phosphoric Acid-50%	NR	150
Phosphorous Pentoxide-50%	NR	100
Pickling Acid	NR	120
Plating Solution	200	230
Potassium Bicarbonate	200	230
Potassium Bromide	200	200
Potassium Carbonate	200	230
Potassium Chloride	200	230
Potassium Dichromate	200	230
Potassium Hydroxide	100	200
Potassium Nitrate	200	230
Potassium Permanganate-5%	150	200
Potassium Permanganate-10%	NR	150
Potassium Sulfate	150	200
Propane	100	100

* Green Box™ chemical grade line pipe and Blue Box® chemical grade tubing and casing Products are offered with Nexus Liner

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Silicic Acid	200	200
Silver Nitrate	200	200
Sodium Acetate	200	200
Sodium Bicarbonate	200	230
Sodium Bisulfate	200	230
Sodium Bromide	200	200
Sodium Carbonate	150	200
Sodium Chlorate	200	230
Sodium Chloride	200	230
Sodium Cyanide	200	230
Sodium Dichromate	200	230
Sodium Ferrocyanide	200	230
Sodium Fluoride	200	230
Sodium Hydroxide	100	150
Sodium Hypochlorite	NR	NR
Sodium Methoxide-40%	100	150
Sodium Nitrate	200	230
Sodium Peroxide	NR	75
Sodium Phosphate	200	200
Sodium Silicate	150	150
Sodium Sulfate	200	230
Sodium Sulfite	200	200
Sodium Thiosulfate	150	150

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Stannic Chloride	200	230
Stearic Acid	150	150
Sulfur Dioxide	NR	150
Sulfuric Acid-25%	NR	150
Sulfuric Acid-70%	NR	100
Sulfurous Acid-5%	NR	150
Tannic Acid	200	200
Tartaric Acid	200	230
Toluene	NR	150
Trichloroacetic Acid	NR	NR
Trichloroethylene-100%	100	150
Triethylamine	NR	100
Trisodium Phosphate	150	150
Turpentine	NR	100
Urea	150	150
Vinyl Acetate	NR	150
Water-Distilled, Deionized	200	230
Water-Fresh, Ph 2-13	200	230
Water-Salt, Brine	200	230
Xylene	150	150
Zinc Chloride	200	230
Zinc Sulfate	200	230

* Green Box™ chemical grade line pipe and Blue Box® chemical grade tubing and casing Products are offered with Nexus Liner

Megamex is a metal supplier for hastelloy, monel, inconel, stainless steel, carbon steel, metal fabrication, nickel alloys, and more.

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INCOLOY® 825

UNS Number N08825

Other common names: Alloy 825, Inconel® 825

Incoloy 825 is a nickel-iron-chromium alloy with additions of molybdenum, copper and titanium. This nickel steel alloy's chemical composition is designed to provide exceptional resistance to many corrosive environments. It is similar to alloy 800 but has improved resistance to aqueous corrosion. It has excellent resistance to both reducing and oxidizing acids, to stress-corrosion cracking, and to localized attack such as pitting and crevice corrosion. Alloy 825 is especially resistant to sulfuric and phosphoric acids. This nickel steel alloy is used for chemical processing, pollution-control equipment, oil and gas well piping, nuclear fuel reprocessing, acid production, and pickling equipment.

In what forms is Incoloy 825 available at Mega Mex?

- Sheet
- Plate
- Bar
- Pipe & Tube (welded & seamless)
- Fittings (i.e. flanges, slip-ons, blinds, weld-necks, lapjoints, long welding necks, socket welds, elbows, tees, stub-ends, returns, caps, crosses, reducers, and pipe nipples)
- Weld Wire (AWS Classification: ERNiFeCr-1 y ENiCrMo-3)
- Wire

What are the characteristics of Incoloy 825?

- Excellent resistance to reducing and oxidizing acids
- Good resistance to stress-corrosion cracking
- Satisfactory resistance to localized attack like pitting and crevice corrosion
- Very resistant to sulfuric and phosphoric acids
- Good mechanical properties at both room and elevated temperatures up to approximately 1000° F

- Permission for pressure-vessel use at wall temperatures up to 800°F

Alloy 825 (UNS N08825) Chemical Composition, %

Ni	Fe	Cr	Mb	Cu	Ti	C	Mn	S	Si	Al
38.0-46.0	22.0 min	19.5-23.5	2.5-3.5	1.5-3.0	.6-1.2	0.05 max	1.0 max	0.03 max	0.5 max	0.2 max

Corrosion Resistance

Alloy 825 has a high level of corrosion resistance. It resists general corrosion, pitting, crevice corrosion, intergranular corrosion, and stress-corrosion cracking in both reducing and oxidizing environments.

In what applications is Incoloy 825 used?

- Chemical Processing
- Pollution-control
- Oil and gas well piping
- Nuclear fuel reprocessing
- Components in Pickling equipment like heating coils, tanks, baskets and chains
- Acid production

ASTM Specifications

Pipe Smls	Pipe Welded	Tube Smls	Tube Welded	Sheet/Plate	Bar	Forging	Fitting
B423				B424	B425	B564	B366, B564

General Mechanical Properties

Tensile (ksi)	.2% Yield (ksi)
85	30-35

Alloy 825 has good mechanical properties from cryogenic temperatures to moderately high temperatures. However, exposure to temperatures above 1000° F can result in microstructural changes that significantly lower ductility and impact strength. Alloy 825 should not be used at temperatures where creep-rupture properties are design factors.

Request a Quote

- All Alloys
- Nickel
  - Nickel 200/201
- Hastelloy
  - Hastelloy B-2

  - Hastelloy B-3
  - Hastelloy C-22
  - Hastelloy C-276
  - Hastelloy X
- **Monel**
  - Monel 400
  - Monel K500
  - Monel R-405
- **Incoloy**
  - Incoloy 800H/800HT
  - Incoloy 825
- **Inconel**
  - Inconel 600
  - Inconel 601
  - Inconel 625
  - Inconel 718
- **Nickel Alloys**
  - Alloy C22
  - Alloy C276
  - Alloy 400
  - Alloy 405
  - Alloy 600
  - Alloy 601
  - Alloy 625
  - Alloy 718
  - Alloy 800H/HT
  - Alloy 825
  - Alloy K500
  - Alloy X
  - Alloy B2
  - Alloy B3
  - Alloy 20
- **Stainless Steel**
  - Stainless 253MA
  - Stainless 310
  - Stainless 317L
  - Stainless 321
  - Stainless 330
  - AL-6XN
  - Alloy 20
- **Duplex Stainless**
  - Duplex 2205
  - Super Duplex 2507
  - Zeron 100
  - LDX 2101
- **Carbon Alloys**
- **Line Sheet PDF**

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Hastelloy® C-276

UNS Number N10276

Other common names: Alloy C276, Hastelloy C, Inconel® C-276

Hastelloy C-276

Hastelloy C276 is a nickel-molybdenum-chromium superalloy with an addition of tungsten designed to have excellent corrosion resistance in a wide range of severe environments. The high nickel and molybdenum contents make the nickel steel alloy especially resistant to pitting and crevice corrosion in reducing environments while chromium conveys resistance to oxidizing media. The low carbon content minimizes carbide precipitation during welding to maintain corrosion resistance in as-welded structures. This nickel alloy is resistant to the formation of grain boundary precipitates in the weld heat-affected zone, thus making it suitable for most chemical process application in an as welded condition.

Although there are several variations of the Hastelloy nickel alloy, Hastelloy C-276 is by far the most widely used.

Alloy C-276 is widely used in the most severe environments such as chemical processing, pollution control, pulp and paper production, industrial and municipal waste treatment, and recovery of sour natural gas.

In what forms is Hastelloy C276 Available at Mega Mex?

- Bar
- Sheet
- Plate
- Pipe & Tube (welded and seamless)
- Pipe Fittings
- Welding Wire

Corrosion Resistant Hastelloy C276

Considered one of the most versatile corrosion resistant alloys available, Hastelloy C-276 exhibits excellent resistance in a wide variety of chemical process environments including those with ferric and cupric chlorides, hot contaminated organic and inorganic media, chlorine, formic and acetic acids, acetic anhydride, seawater, brine and hypochlorite and chlorine dioxide solutions. In addition, alloy C-276 resists formation of grain boundary precipitates in the weld heat affected zone making it useful for most chemical processes in the as-welded condition. This alloy has excellent resistance to pitting and stress corrosion cracking.

What are the characteristics of Hastelloy C276?

- Excellent corrosion resistance in reducing environments
- Exceptional resistance to strong solutions of oxidizing salts, such as ferric and cupric chlorides
- High nickel and molybdenum contents providing good corrosion resistance in reducing environments
- Low carbon content which minimizes grain-boundary carbide precipitation during welding to maintain resistance to corrosion in heat-affected zones of welded joints
- Resistance to localized corrosion such as pitting and stress-corrosion cracking
- One of few materials to withstand the corrosive effects of wet chlorine gas, hypochlorite and chlorine dioxide

Chemical Composition, %

Ni	Mo	Cr	Fe	W	Co	Mn	C
Remainder	15.0-17.0	14.5-16.5	4.0-7.0	3.0-4.5	2.5 max	1.0 max	.01 max
V	**P**	**S**	**Si**				
.35 max	.04 max	.03 max	.08 max				

In what applications is Hastelloy C-276 used?

- Pollution control stack liners, ducts, dampers, scrubbers, stack-gas reheaters, fans and fan housings
- Flue gas desulfurization systems
- Chemical processing components like heat exchangers, reaction vessels, evaporators, and transfer piping
- Sour gas wells
- Pulp and paper production
- Waste treatment
- Pharmaceutical and food processing equipment

Fabrication with Hastelloy C-276

UNS N10276

Hastelloy C-276 alloy can be forged, hot-upset and impact extruded. Although the alloy tends to work-harden, you can have it successfully spun, deep-drawn, press formed or punched. All of the common methods of welding can be used, although the oxyacetylene and submerged arc processes are not recommended when the fabricated item is for use in corrosion service.

For more information on fabrication and machining click here.

Hastelloy C-276 Welding Material

Alloy C276 welding products are used as matching composition filler material for welding C276 alloy wrought and cast products, for dissimilar welding applications including other nickel-chromium-molybdenum alloys and stainless steels, and for weld overlay or cladding of steels.

Specifiacations: ASME-SFA-5.14 ERNiCrMo-4

Forms of C276 Filler Metal Available at Mega Mex

- .031 in or .8 mm in diameter
- .035 in or .9 mm in diameter
- .039 in or 1.0 mm in diameter
- .045 in or 1.1 mm in diameter
- .047 in or 1.2 mm in diameter
- .062 in or 1.6 mm in diameter
- .078 in or 2.0 mm in diameter
- .093 in or 2.4 mm in diameter
- .125 in or 3.2 mm in diameter

Filler metals are available in spools and in cut lengths from the above diameters. Straight lengths are available in 36" lengths.

ASTM Specifications

Pipe Smls	Pipe Welded	Tube Smls	Tube Welded	Sheet/Plate	Bar	Forging	Fitting	Wire
B622	B619	B622	B626	B575	B574	B564	B366	

Mechanical Properties
Typical Room Temperature Tensile Properties of Annealed Material

Product Form	Tensile (ksi)	.2% Yield (ksi)	Elongation %
Bar	110.0	52.6	62
Plate	107.4	50.3	67
Sheet	115.5	54.6	60
Tube & Pipe	105.4	45.4	70

Request a Quote

- **All Alloys**
- **Nickel**
  - Nickel 200/201
- **Hastelloy**
  - Hastelloy B-2
  - Hastelloy B-3

- Hastelloy C-22
- Hastelloy C-276
- Hastelloy X
- **Monel**
  - Monel 400
  - Monel K500
  - Monel R-405
- **Incoloy**
  - Incoloy 800H/800HT
  - Incoloy 825
- **Inconel**
  - Inconel 600
  - Inconel 601
  - Inconel 625
  - Inconel 718
- **Nickel Alloys**
  - Alloy C22
  - Alloy C276
  - Alloy 400
  - Alloy 405
  - Alloy 600
  - Alloy 601
  - Alloy 625
  - Alloy 718
  - Alloy 800H/HT
  - Alloy 825
  - Alloy K500
  - Alloy X
  - Alloy B2
  - Alloy B3
  - Alloy 20
- **Stainless Steel**
  - Stainless 253MA
  - Stainless 310
  - Stainless 317L
  - Stainless 321
  - Stainless 330
  - AL-6XN
  - Alloy 20
- **Duplex Stainless**
  - Duplex 2205
  - Super Duplex 2507
  - Zeron 100
  - LDX 2101
- **Carbon Alloys**
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Attachment D

Maximum Allowable Bottom Hole Pressure and Maximum Allowable Surface Injection Pressure.

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

BHP_{max} = (Formation Fracture Gradient) (Long String Casing Depth)

BHP_{max} = .75 psi/ft X 2,810′ (proposed casing point)

BHP_{max} = 2,107 psi

The maximum allowable surface injection pressure (MASIP) shall be calculated using the following formula:

MASIP = Long String Casing Depth X [Formation Fracture Gradient – (Pressure Gradient of One Foot of Water at 62 Degrees Fahrenheit (.433) X Maximum Specific Gravity (1.00*))]

.75 - .433 = .317

2,810' X .317 = 890.77

MASIP = 890 psi

***If specific gravity over 1.0, MASIP must be adjusted downward accordingly.**

Attachment E

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

Protection of USDW

CORRECTIVE ACTION PLAN AND COMPLIANCE SCHEDULE

Vickery has utilized multiple and redundant search methods to determine the location and status of artificial penetrations of the injection zone within the AOR. A corrective action plan is not required because it has been determined that all artificial penetrations have been properly plugged and abandoned with plugs set such that these wells pose no threat to groundwater due to upward waste migration. Should a corrective action plan be required in the future, it will be proposed in accordance with OEPA guidelines and submitted to OEPA for approval.

Ohio Environmental Protection Agency

DIVISION OF DRINKING AND GROUND WATERS

UNDERGROUND INJECTION CONTROL PERMIT TO DRILL: CLASS I HAZARDOUS WELL

Ohio Permit No.:	UIC 03-72-020-PTD-I
Date of Issuance:	
Effective Date:	
Date of Expiration:	4 years after issuance if issued

Name of Applicant:	Vickery Environmental, Inc.
Facility Location:	3956 State Route 412 Vickery, Ohio 43464
Mailing Address:	3956 State Route 412 Vickery, Ohio 43464
County:	Sandusky
Township:	Riley
Section:	Section 26
Well Name:	VEI Disposal Well No. 8
Well Location:	41°22'13" N/-82°58'35" W
Total Depth:	+/- 2,900' Total Vertical Depth to Mt. Simon (measured from Kelly Bushing (KB) height). Ground level elevation estimated at 607' above sea level.

The above, named permittee is hereby issued a Permit to Drill for the above described underground injection well pursuant to Chapter 3745-34 of the Ohio Administrative Code.

Issuance of this Permit to Drill does not constitute expressed or implied assurances that if constructed and/or modified in accordance with those specifications and/or information accompanying the permit application, the permittee will be granted an operating permit(s).

The permittee, its employees, subsidiaries, successors, contractors, and others acting in concert with the permittee are solely responsible to maintain control of the well at all times and will ensure at all times, the drilling and construction of the well will be protective of human health and the environment. This Permit to Drill is issued subject to the conditions provided in the permit and all applicable provisions of Chapter 6111. of the Ohio Revised Code and the rules adopted thereunder; of Chapter 3745-34 of the Ohio Administrative Code; and all applicable provisions of 40 C.F.R. Parts 124, 144, and 146 which are also hereby incorporated. Nothing in this Permit to Drill should be deemed to relieve the permittee of any obligations under applicable local, state, or federal laws. Where these incorporated provisions conflict with the expressed terms and conditions, the expressed terms and conditions shall control.

This permit and the authorization to drill shall expire at midnight, unless terminated, on the date of expiration indicated.

Laurie A. Stevenson, Director
Ohio Environmental Protection Agency

TABLE OF CONTENTS

Page

PART I – General Permit Conditions

A. Effect of Permit 1

B. Permit Actions 1

C. Duration of Permit 1

D. Severability 2

E. Confidentiality 2

F. Duties and Requirements 2

G. Inspection and Entry 3

H. Analysis of Data 4

I. Financial Responsibility 4

J. Plugging and Abandonment 4

K. Duty to Provide Information 5

PART II – Well Specific Conditions

A. Construction Requirements 6

B. Requirements for Drill Cutting and Cores 7

C. Geophysical Well Logging 7

D. Formation Testing 9

E. Formation Testing Requirements 9

F. Injection Pressure Limitations 10

G. Injection Formation Stimulation Prerequisite 11

H Record Requirements 11

I. Well Closure Plan 12

ATTACHMENTS

A. Closure Plan

B. Geotechnical Information

C. Well Construction

D. Surface and Bottom Hole Pressure Limitations

E. Corrective Action

PART I
GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

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

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

B. PERMIT ACTIONS

1. <u>Modification, Revocation, Reissuance and Termination.</u> The Director may, for cause or upon request from the permittee, modify, revoke, and reissue, or terminate this permit in accordance with Ohio Administrative Code (OAC) Rules 3745-34-07, 3745-34-23, and 3745-34-24, and 3745-34-26. Also, the permit is subject to OAC Rule 3745-34-27(A). Changes in construction may be approved as minor modifications for cause as specified in OAC Rule 3745-34-25. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated non-compliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

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

C. DURATION OF PERMIT (OAC Rule 3745-34-21(D))

This Permit to Drill shall terminate within eighteen (18) months of the effective date if the permittee has not undertaken a continuing program of construction or has not entered into a binding contractual obligation to undertake and complete construction within a reasonable time.

D. 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.

E. 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, 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 at the permitted facility.

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

2. 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. Reporting Requirements

   a. Pursuant to OAC rule 3745-34-27(A)(1), changes in construction plans during construction may be approved by the Director as minor modifications (OAC Rule 3745-34-25). No such changes may be physically incorporated into construction of the well prior to approval of the modification by the Director.

   b. Written notice of any planned physical alterations to the well shall be given to Ohio EPA ten (10) days prior to commencement of any alteration. A shorter time period may be approved by the Director. Furthermore, the permittee shall provide justification for any planned physical alterations to the permitted well. Prior to implementation of any alteration, the permittee shall have written approval for the proposed alteration from Ohio EPA.

c. The permittee shall report to the Director any non-compliance which may endanger health or the environment. All available information shall be provided orally within twenty-four (24) hours from the time the permittee becomes aware of such noncompliance. The following events shall be reported orally within twenty-four (24) hours:

   i. Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water.
   ii. Any non-compliance with a permit condition, or malfunction of the drilling equipment, which may cause fluid migration into or between underground sources of drinking water.

d. A written submission shall also be provided within five (5) working days of the time the permittee becomes aware of the circumstances of such non-compliance. The written submission shall contain the following:

   i. A complete description of the non-compliance and its cause; and
   ii. The time, date, and duration of the period of non-compliance; and
   iii. If the non-compliance has not been corrected, the anticipated time it is expected to continue; and
   iv. Identification and quantification (including sample results when available) of all substances released to the environment or involved in the incident or event; and
   v. A description of all remedial measures taken or to be taken; and
   vi. A description of the extent of contamination or damage to the environment; and
   vii. Any monitoring or other documentation available about the incident; and
   viii. A description of the steps taken or planned to reduce or eliminate the possibility of recurrence of the non-compliance.

4. Injection The permittee may not commence injection of waste into the well until a Permit to Operate application has been submitted to Ohio EPA for review and final approval for a Permit to Operate has been issued by the Director of Ohio EPA. Any other injection required during well testing to acquire data or to perform a well stimulation is excluded from this stipulation but shall be conducted in accordance with a plan(s) approved, in advance, by Ohio EPA and will be subject to all other provisions of this permit.

G. INSPECTION AND ENTRY

1. The Ohio EPA shall have unlimited authority and access to witness or to inspect for compliance with this permit; all drilling, testing, logging, and construction of the well. The permittee shall submit a schedule of such activities in writing to Ohio EPA prior to commencement. The permittee shall notify Ohio EPA at a minimum of twenty-four (24) hours prior to any logging or well tests.

2. The permittee shall inform Ohio EPA of the progression and scheduling of drilling and testing **daily**. A written driller's report, containing information specified in Part II (H)(3) of this permit shall be submitted daily in an electronic format. For the purpose of this permit to drill provision, **daily** is defined as occurring at least once every calendar day.

H. ANALYSIS OF DATA

1. Field results from all well logging shall be submitted within ten (10) days of completion of the activity. A field log shall be made available the day of the logging at Ohio EPA's request.

2. The following results obtained during construction of the well, along with a technical appraisal of the results, shall be submitted to the Ohio EPA, in the form of a report (duplicate) or within an application for a Permit to Operate (five paper copies required), no later than sixty (60) days after the well drilling and testing is completed, including:

    a. All geophysical logs, well completion, mud log, well testing, core data, and any other technical data; and,

    b. Results of injection and reservoir testing. These results are to include information on effective reservoir thickness, reservoir pressure build-up, and anticipated radial movement of the waste.

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

1. The permittee has provided a demonstration of adequate financial resources to plug and abandon the four existing wells. Adequate financial assurance for the two proposed wells must be established and approved by Ohio EPA prior to the commencement of drilling. Cost estimates to cover closure and post-closure costs of the two additional wells proposed is included within Attachment A of this Permit to Drill.

2. The permittee shall notify Ohio EPA within ten (10) days of bankruptcy or insolvency (in any form) of the permittee or the entity providing financial assurance. In addition, notice shall be given within ten (10) days of event if any bonds, insurance or other security submitted under this paragraph lapse, are transferred, or are otherwise compromised.

3. The permittee is required to establish, maintain financial responsibility and resources to close, plug, and abandon the injection well. The obligation to maintain financial resources to close, plug, and abandon the well survives the termination of this permit.

4. During the operating life of the facility, the permittee shall keep on file at the facility a copy of the latest closure and post-closure cost estimates prepared in accordance with OAC Rules 3745-34-60 and 3745-34-61.

J. PLUGGING AND ABANDONMENT (OAC Rule 3745-34-36)

1. If plugging and abandonment of this well is required, then the well shall be plugged and abandoned in accordance with the plans found in Attachment A of this permit. The plan is subject to final of approval by Ohio EPA. The requirement to maintain and implement the plugging and abandonment plan is enforceable until plugging and abandonment are completed in accordance with the plan.

2. The permittee remains responsible for this well and any environmental impact caused by the drilling or use of the well, whether authorized or unauthorized, at all times, including after plugging and abandonment of the well.

3. In accordance with OAC rule 3745-34-60(B), the permittee shall notify the Director at least sixty (60) calendar days before the anticipated date of plugging and abandonment of the well, unless a shorter notice period is approved by the Director.

4. Within twenty-four (24) months of well completion, the permittee is required to submit to Ohio EPA an application for a Permit to Operate that, at a minimum, meets all requirements of OAC Rule 3745-34-15 to be considered a complete application. If a complete application for a Permit to Operate is not submitted to Ohio EPA within this time frame, the permittee is required to begin implementation of its current and approved closure plan.

K. DUTY TO PROVIDE INFORMATION

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

Part II
WELL SPECIFIC CONDITIONS

A. CONSTRUCTION REQUIREMENTS (OAC Rule 3745-34-54)

1. At a minimum, the permittee shall construct the well in accordance with the construction standards of OAC Rule 3745-34-54. All well materials shall be compatible with any fluids with which the materials may be expected to come into contact and designed for the life expectancy of the well.

2. The permittee shall follow drilling and construction procedures as set forth in the permittee's approved application, including all revisions submitted to Ohio EPA or as otherwise specified within this Permit to Drill. Proposed casing program and cementing procedures are included in Attachment C of this Permit to Drill. Appropriate mechanical and engineering practices shall be applied to ensure that the well pressure is controlled at all times.

    a. Only potable water shall be used for mixing in drilling or completion operations.

    b. Conductor casing shall meet or exceed the standards as established in the Drilling Plan section of the permit applications. The conductor shall be installed at a depth which adequately allows emplacement of the surface casing.

    c. Surface casing shall, at a minimum, extend 100 feet into the confining bed below the lowermost USDW and be cemented to surface using a minimum of 120% of the calculated annular volume.

    d. Centralizers shall be placed to ensure adequate cementation of the casing and ensure protection of the USDW. At a minimum, surface casing shall be centralized at the shoe and on every second joint thereafter.

    e. Before drilling below the surface casing, a blowout preventer, control head or other connections shall be installed to keep the well pressure under control at all times.

    f. Deviation checks shall be performed at sufficiently frequent drilling intervals to assure the measurements needed to calculate and plot the well path. The measured depth, inclination, and azimuth shall be recorded at each survey point. The data shall be used to monitor the well path, to determine the exact bottom hole location, and to assure that no vertical avenues are created which would allow fluid migration pursuant to OAC Rule 3745-34-55(A)(1).

    g. Long string casing with a sufficient number of centralizers shall extend into the top of the Mt. Simon Formation and be cemented to surface. The cement volume shall be a minimum of 120% of the calculated annular volume.

    h. Long string casing centralizers shall, at a minimum, satisfy standards established in the permit applications. Centralizers shall be placed to ensure adequate cementation of the casing and to ensure that the lowermost USDW is protected. At a minimum, each joint of the bottom 500 feet of the long string casing shall be centralized, and subsequent centralizers shall be placed on every second joint to the surface thereafter.

i. Neither the cement nor associated cementing equipment shall be subject to the resumption of drilling until the cement has developed sufficient compressive strength to support the casing and restrict fluid movement between formations. The cement bond of each casing string shall be demonstrated by an approved bond log.

j. The permittee shall obtain representative samples of the cement mixture and additives for each cementing operation. At a minimum, samples shall be collected at intervals of approximately 25%, 50%, 75%, and 95% of the total volume used in each cementing operation. Laboratory analyses shall be performed for at least the following:

   i. Compressive strength;
   ii. Permeability; and
   iii. Fluid loss.

3. Under no circumstances shall the Precambrian Middle Run Formation be penetrated during drilling operations.

B. REQUIREMENTS FOR DRILL CUTTINGS and CORES (OAC Rule 3745-34-55)

1. Drill cuttings shall be sampled and collected at 10′ intervals, at a minimum, except if whole cores are being collected from the interval. The cuttings shall be representative of the drilled intervals and be placed in appropriately labeled sample bags. Special attention and monitoring for hazardous waste conditions will be required for drill cuttings and produced fluids when the top of the injection zone is encountered and through total depth. The drill cuttings from the injection zone should be treated and disposed per hazardous waste requirements.

2. The permittee is responsible for care and security of well cuttings samples and any core that is obtained. If requested, drill cuttings and cores shall be delivered to the Ohio Department of Natural Resources' Core Repository.

3. OAC Rule 3745-34-55(B) requires that whole or sidewall cores of the confining and injection zones be taken. The permittee shall ensure that any extracted core is representative of the intended interval and that coring operations result in optimum core uniformity and recovery. Procedures for testing the core(s) shall be submitted to Ohio EPA for prior approval, if applicable. OAC Rule 3745-34-55(D)(3) requires that the permittee submit information detailing the physical and chemical characteristics of the confining and injection zones, including an accurate description of the fluids present in these zones.

   Coring completed as required by Permit to Drill UIC 03-72-019-PTD-I will, for purposes of this permit, meet the requirements of OAC Rule 3745-34-55. However, the Director may require additional coring if it is determined that cores extracted under Permit to Drill UIC 03-72-019-PTD-I are not adequate for satisfying the requirements of OAC Rule 3745-34-55.

C. GEOPHYSICAL WELL LOGGING REQUIREMENT (OAC Rule 3745-34-55)

At a minimum, the following electric and geophysical well logs (or equivalent logs) shall be performed unless otherwise approved by the Director: (All procedures must be pre-approved by Ohio EPA).

1. Prior to the installation of the surface casing:
   a. Gamma Ray;
   b. Spontaneous Potential;
   c. Lateral Induction Resistivity;
   d. Compensated Neutron Density;
   e. Compensated Formation Density; and,
   f. Caliper.

2. After surface casing has been set and cemented:
   a. Gamma Ray;
   b. Temperature;
   c. Variable Density; and
   d. Cement Bond.

3. Prior to installation of the long string casing:
   a. Gamma Ray;
   b. Spectral Gamma Ray;
   c. Photo electric;
   d. Spontaneous Potential;
   e. Lateral Induction Resistivity;
   f. Nuclear Magnetic Resonance (NRM);
   g. Compensated Neutron;
   h. Compensated Formation Density;
   i. Temperature;
   j. Fracture Identification;
   k. Long Spaced Sonic; and
   l. Caliper.

4. After long string casing has been set and cemented:
   a. Gamma Ray;
   b. Temperature;
   c. Variable Density;
   d. Cement Bond; and,
   e. Casing Inspection.

5. To be considered approvable for a Permit to Operate, the permittee shall provide a schedule and plan for Ohio EPA review and approval at least thirty (30) days prior to testing, including the following:
   a. Baseline Differential Temperature Survey;
   b. Annulus Pressure Test;
   c. Radioactive Tracer Survey;
   d. Post-Injection Differential Temperature Survey; and,
   e. Bottom Hole Pressure Falloff Test.

6. The above electric and geophysical well log requirements do not limit or relieve the permittee from other or additional logging or testing requirements which may be deemed necessary by the Director. The permittee shall notify Ohio EPA a minimum of twenty-four (24) hours prior to any well logging. This requirement does not apply to the mud log which will be performed continuously from spud point to total depth.

   Should cementing procedures or logging results indicate potential for an inadequate cement job, the permittee shall conduct all necessary operations to ensure a quality cement job.

D. FORMATION TESTING

1. In accordance with OAC rules 3745-34-37(E), 3745-34-38(A)(1), and 3745-34-55(D), the permittee shall provide an adequate demonstration of the fracture gradient and the fracture initiation, propagation, and closure pressures. An adequate demonstration is required prior to issuance of a Permit to Operate. The permittee shall collect all data necessary to provide a conclusive demonstration. The permittee must obtain approval from Ohio EPA for all procedures prior to this demonstration.

2. Should the permittee choose to perform an injectivity test, to fulfill the requirements of OAC Rule 3745-34-55(E), the test shall be conducted using an Ohio EPA approved fluid and method.

3. Should the permittee choose to perform a pressure fall-off test, the permittee shall provide a plan for Ohio EPA review and approval at least thirty (30) days prior to testing.

4. The above minimum testing requirements do not limit or relieve the applicant from additional testing if it is determined by Ohio EPA that additional testing is necessary. The permittee shall notify Ohio EPA at a minimum of twenty-four (24) hours prior to any formation testing.

E. FORMATION TESTING REQUIREMENTS

1. The permittee shall recover stabilized fluid samples in a manner that shall maximize accurate measurement of pH and chemical constituents. The permittee shall record the following minimum measurements after a representative wellbore volume has been purged, to ensure that formation parameters have stabilized:

   a. pH;
   b. Specific Gravity; and
   c. Specific Conductance.

2. Upon twenty-four (24) hour prior notice, a split sample of each recovered fluid sample shall be provided to Ohio EPA for analysis if requested. All sampling depths will be agreed upon by Ohio EPA prior to sampling.

3. All fluid samples recovered from the confining and injection zones shall be evaluated for a minimum of the following:

   a. Specific Gravity;
   b. Specific Conductance;
   c. Temperature;
   d. pH;
   e. Total Suspended Solids;
   f. Total Solids;
   g. Total Organic Carbon;
   h. Chlorides;
   i. Sulfates;
   j. Sulfide;
   k. Viscosity;
   l. Dissolved Oxygen;
   m. Alkalinity;
   n. Acetone;
   o. Aluminum, Total;
   p. Arsenic, Total;
   q. Barium, Total;
   r. Benzene;
   s. Cadmium;
   t. Calcium, Total;
   u. Chlorobenzene;
   v. 1, 2-Dichloroethane;
   w. Chromium, Total;

x. Copper, Total;
y. Ethylbenzene
z. Flourides;
aa. Iron, Total;
bb. Lead, Total (TCLP if > 5.0 mg/l);
cc. Magnesium, Total;
dd. Manganese, Total;
ee. Mercury;
ff. Methyl Isobutyl Ketone;
gg. Nickle, Total;
hh. Nitrates;
ii. Potassium, Total;
jj. Selenium;
kk. Silver;
ll. Sodium, Total;
mm. Strontium, Total;
nn. Toluene;
oo. Trichloroethylene;
pp. Xylene;
qq. Zinc, Total;
rr. BTEX, Total; and
ss. Pyridine.

4. In accordance with Ohio Revised Code Section 6111.043(D), the permittee shall submit to the Director any information or test results that the Director determines is necessary to more adequately define hydrogeologic conditions at the site of the well and to protect the lowermost USDW.

F. INJECTION PRESSURE LIMITATION (OAC Rule 3745-34-56)

1. Except during stimulation or testing approved in advance by Ohio EPA, injection pressure at the wellhead shall not exceed a maximum which shall be calculated in such a way as to assure that the pressure in the injection zone 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 a USDW. Refer to Attachment D for pressure limitation calculations for both bottom hole and surface pressures.

2. Injection between the outermost casing protecting USDWs and the wellbore is strictly prohibited. At no time shall injection occur into any formation without prior approval from Ohio EPA.

3. No waste water shall be injected into this well prior to receipt of a final Permit to Operate issued by the Director of Ohio EPA and any conditions set forth therein.

4. Injection necessary to conduct well testing or stimulation shall be conducted in accordance with limitations established in Part I(F)(4) of this permit.

G. INJECTION FORMATION STIMULATION PREREQUISITE

1. Hydraulic fracture stimulation of the injection formation is prohibited unless the permittee has secured written approval from Ohio EPA. To receive authorization from Ohio EPA to fracture stimulate the injection formation, the permittee must demonstrate that such stimulation shall not initiate fractures in the confining zone or cause movement of injection or formation fluids into a USDW.

2. If the permittee chooses to perform an acid stimulation of the injection formation the permittee must submit a plan to Ohio EPA for approval. The permittee must demonstrate that the injection pressure does not exceed the formation fracture pressure.

H. RECORD REQUIREMENTS

1. Records of all sampling, testing, and analysis shall include:
   a. The date, exact place, and time of sampling, testing, or measurements;
   b. The individual(s) who performed the sampling, testing, or measurements;
   c. A precise description of sampling and testing methodology and the handling of samples thereof;
   d. The date(s) analyses were performed;
   e. The name(s) of individual(s) who performed the analysis;
   f. The analytical techniques or methods used; and
   g. The results of the analyses.

2. Analysis of fluid samples shall comply with applicable analytical methods cited and described in 40 CFR 136.3 or in Appendix III of Part 261.

3. At all times throughout the drilling and construction of the well, the permittee shall maintain a drilling record at the well site. At a minimum, the drilling record shall note and record the following:
   a. Current depth;
   b. Drilling rate of penetration (drilling time log);
   c. Lithology;
   d. Size of drill bit;
   e. Water/fluid bearing zone(s);
   f. Oil and gas shows;
   g. Lost circulation zone(s);
   h. Deviation survey results, including bottom hole location;
   i. Drilling fluid information, at a minimum shall include:
      i. Depth;
      ii. Weight;
      iii. Viscosity;
      iv. Fluid loss test;
      v. Specific conductance; and
      vi. pH.

4. Ohio EPA shall be granted access to view, examine, take notes from and/or copy the drilling record at all times. Within thirty (30) days of completion of drilling and construction operations, a true copy of the drilling record shall be delivered to Ohio EPA.

5. The permittee shall inform Ohio EPA of the progression and scheduling of drilling and testing **daily**. A written daily driller's report shall be submitted electronically. At a minimum, the daily drilling report shall contain the following information:

   a. General information:
      i. Date and time of report;
      ii. Well depth;
      iii. Formation;
      iv. Lithology;
      v. Comments; and
      vi. Name/title of person preparing the report.

b. Daily drilling and completion report:
   i. Report date;
   ii. Spud date;
   iii. Current drilling depth;
   iv. Present operation (e.g. drilling, waiting on cement, etc.);
   v. Casing/Cementing data – at a minimum date set, depth, casing size diameter, centralizer locations, sacks of cement;
   vi. Bit data – bit number, size, type, hours in use, footage drilled, weight on bit, revolutions per minute;
   vii. Mud data – at a minimum, items in Part II (H)(3)(i) of the permit to drill; and,
   viii. Summary of activities since the previous report.

c. Activities, including those outlined in the drilling plan, projected to occur during the next twenty-four (24) hours.

I. WELL CLOSURE PLAN

1. At a minimum, the permittee shall plug and abandon the well in accordance with the standards set forth in OAC Rules 3745-34-36, 3745-34-39, and 3745-34-60.

2. The permittee shall inform Ohio EPA of their intentions to plug and abandon the well at least sixty (60) days prior to the scheduled plugging date. The permittee shall obtain Ohio EPA approval of the closure plan prior to initiating plugging and abandonment operations.

3. The permittee shall provide a report of the plugging and abandonment to Ohio EPA within sixty (60) days after completion of the plugging and abandonment activities.

Attachment A

I. Closure Plan

II. Post Closure Plan

Attachment A

I. Closure Plan

12.0 PLUGGING AND ABANDONMENT PLAN

12.1 PLUGGING AND ABANDONMENT

The typical plugging and abandonment procedure to be applied to the Vickery wells is as follows:

1. Perform a 48-hour injection/48-hour falloff test (ambient monitoring) of the formation using the plant's injection pumps and using a surface readout downhole pressure gauge, in accordance with OAC Rule 3745-34-60(D)(1).

   The actual length of the injectivity/falloff test must be approved in advance by Ohio EPA.

   OAC Rule 3745-34-60(D)(2) requires that "Prior to well closure, the owner or operator of a class I hazardous waste injection well shall conduct appropriate mechanical integrity testing 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:

   a) Pressure tests with liquid or gas; *or*
   b) Radioactive tracer surveys; *or*
   c) Noise, temperature, pipe evaluation, or cement bond logs; *or*
   d) Any other test required by the director.

   An annulus pressure test, radioactive tracer log, multi-pass temperature log, and a casing inspection log is planned. The mechanical integrity tests must be approved in advance by Ohio EPA.

2. Increase the tubing-casing annulus pressure to greater than 1,000 psi and allow the pressure to stabilize. Monitor and record the pressure for one hour. If the pressure loss is less than 3% in a one-hour period, the test will be considered successful.
3. Perform a multi-pass temperature decay log, logging from total depth to surface. Fluid

injected during the pumping phase of the test must be at least 10° warmer or cooler than the ambient temperature in the well.

4. Perform radioactive tracer logging consisting of an initial base gamma ray pass, two point statistical check, two series of ejections and subsequent chase passes, two time drive surveys and a final base gamma ray pass.

5. Move in and rig up a well service unit and ancillary equipment. Pump three wellbore volumes of fresh water to flush the well, then pump 10 lb/gal sodium chloride brine to kill the well.

6. Remove the well head and install a blow out preventer (BOP). Decontaminate and/or dispose of the well head in an appropriate manner.

7. Connect a 2-inch line from the tubing-casing annulus valve to a holding tank. Pick up on the tubing to pull the seal assembly from the polished bore receptacle. Pump brine down the tubing and up the annulus to remove the diesel fuel well cap from the annulus. Catch the diesel in the holding tank.

8. After all diesel fuel has been pumped from the well, cease pumping and allow the pressure in the tubing and the annulus to equalize.

9. Pull the fiberglass tubing and the seal assembly from the well and decontaminate and/or dispose of in an appropriate manner. Perform Casing inspection log after fiberglass tubing has been removed.

10. Pick up 18 joints of the 2-7/8" fiberglass tubing removed from the well and run into the well on workstring tubing. Tag plug back total depth (PBTD) with the fiberglass tubing. Balance a plug of Epseal acid resistant cement from PBTD to a point above the top of the

Knox formation (depth varies from 2330 ft to 2360 ft RKB among the four remaining wells).

11. Pull out of the well with the tubing and decontaminate and/or dispose of the fiberglass tubing as above. Wait a minimum of 48 hours for the Epseal cement to set.

12. Run the workstring into the well and tag the top of the Epseal plug. Close the BOP and test the plug to 500 psi. If the pressure loss is less than 3% in a one-hour period the test will be considered successful.

13. A manufacturing quality certificate from the maker of the cement will be provided to OEPA prior to the start of cementing operations.

Fill the casing with Class "A" cement, using the balanced plug method, from the top of the Epseal plug to the surface. A cementing truck with continuous density monitoring equipment will be utilized. Take a sample of the cement from the initial 20% of the stage volume and from the final 20% of the stage volume to be used for curing time determination. Wait on cement for at least 4 hours between plugs and tag each plug prior to spotting the successive plug.

14. Cut off the wellhead and casing three feet (3') below ground level and weld a steel plate onto the top of the casing. The plate will have a steel tag with the following inscribed:

Vickery Environmental, Inc.
Hazardous Waste Disposal Well
Ohio EPA UIC # ------------
Plugged: (Date)

15. Rig down and move off the service unit and ancillary equipment. Decontaminate and

dispose of any remaining contaminated well equipment.

16. Prepare a report of the plugging and abandonment operations for submittal to the OEPA within the time frame and containing the information specified in OAC Rule 3745-34-60 (C).

NOTE: All cement volumes will be calculated for each specific well.

* The proposed P&A procedure assumes that injection activities will be ceased for all wells, and then the wells will be plugged. If an individual well is to be plugged, but injection continued in other wells, a P&A procedure similar to that utilized previously for the #1 and #3 wells would be followed.

** Depths will be referenced to original RKB. The volume of Epseal specified is calculated to fill the well to the indicated point relative to RKB assuming there is no fill in the well. Any fill present would only cause the specified volume of Epseal to fill the well to a higher level, and cause a correspondingly lesser amount of Class A cement to be required. No excess volume is included in the above calculated values.

*** Assumes Class A cement is mixed to 15.6 lbs./gal.. This results in 1.18 cu. ft. of cement being produced per sack mixed.

Attachment A

II. Closure Cost Estimate

SECTION 4

INJECTION UNIT CLOSURE COST ESTIMATE

CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
INJECTION WELLS AND KNOX KERBEL WELL PLUGGING AND ABANDONMENT. RIGS, DRILLING, MITs AND MUD FOR ~~4~~6 INJECTION WELLS AND ONE DEEP MONITORING WELL @ ~~$353,484~~$385,000/WELL	~~5~~7	~~$353,484~~ $385,000	~~$1,767,420~~ $2,695,000
DISPOSAL OF TUBING AND SEALS, ~~24~~ 36 TONS @ ~~$0.13~~ $0.20/LB	~~48,000~~ 72,000	~~$0.13~~ $0.15	~~$6,240~~ $10,800
ANNULUS FLUID DISPOSAL ~~8,000~~ 12,000 GALLONS @ $0.71GAL	~~8,000~~12,000	~~$0.71~~ $0.77	~~$5,680~~ $9,240
PLUGGING AND ABANDONMENT OF LOCKPORT WELL @$42,882	1	$42,882	$42,882
DISPOSAL OF WATER GENERATED FROM ABANDONMENT @ 10,000 GALLON PER WELL, ~~5~~7 WELLS @ $1.00/GAL	~~50,000~~ 70,000	$1.00	~~$50,000~~ $70,000
WATER GENERATED FROM ABANDONMENT OF LOCKPORT WELL @ 4000 GALLON @ $1.00/GAL	4,000	$1.00	$4,000
TOTAL OF INJECTION UNIT CLOSURE			~~$2,043,430*~~ $2,831,922

~~***2018 Inflation adjusted total cost + 1.8% Inflation Adjustment**~~

Attachment B

I. Geology Description

II. Seismic Discussion

Attachment B

I. Geology Description

5.0 GEOLOGY

5.1 INTRODUCTION

The siting of Class 1 hazardous waste wells is limited to areas that are geologically suitable. Geologic suitability is based on an analysis of the regional and local geology. Vickery has previously studied in detail both the regional and site specific geology. This was included in Attachment B of the July 5, 1994 UIC Permits to Operate and is included with the previous permit copy in Attachment A of this document. Therefore, only a very brief summary of the regional and local geology is included here.

5.2 REGIONAL GEOLOGY

The stratigraphy of Ohio is comprised of Paleozoic carbonate and clastic rock units unconformably overlying a Precambrian basement. The Paleozoic units are in turn overlain by a relatively thin veneer of Pleistocene glacial drift and localized Holocene sediments. Figure 5-1 is a geologic time scale showing the relationship of various geological units along with approximate formation ages. Figure 5-2 indicates the stratigraphic equivalency of formation names which may be encountered in the literature when working in this region, and general formation lithology.

Structurally, Ohio occupies a relatively high position located between three major basins. Figure 5-3 shows the states location between the Michigan Basin, Illinois Basin and the Appalachian Basin. The principle structural features in Ohio are indicated on Figures 5-4, 5-5 and 5-6. The East Continent Rift Basin (ECRB) depicted on Figure 5-7 has only relatively recently been named and described as an addition to the major basement structural features of the region. Figure 5-8 shows the location of the Seneca Geophysical Anomaly to the southwest of the Vickery site. The anomaly is geophysically a strong magnetic positive and a relative gravity minimum. This figure also depicts the location of basement related structures such as faulting, the ECRB and the Grenville Front Tectonic Zone boundary. Reactivation of movement along zones of weakness aligned with basement faulting may be a factor in controlling faulting in the Paleozoic section.

5.2.1 Structure

In Ohio, the present configuration of the basement surface is the result of uplift and erosion during late Precambrian time, followed by burial in a sedimentary cover and warping during the Paleozoic. The Cincinnati Arch and the Findlay Arch should not be considered as one continuous structure. They each lose their identity on the Ohio-Indiana platform.

Figure 5-9 is a structure contour map on the Precambrian unconformity surface by Baranoski(2002) which integrates subsurface well control and seismic data where available. The map is based on a total of 310 well control points, of which 207 are within Ohio. It is interesting to note that the Precambrian structure is generally shown to be more complex in areas of higher density well control or seismic coverage. The more complex contouring is likely representative of the Precambrian surface overall, but the scarcity of control in many areas makes only a depiction of the general dip rates and direction possible. Figure 5-10 is a cross section enlarged from Baranoski's map. It shows the structural configuration on an east-west traverse across Ohio. Additional information regarding the Precambrian surface underlying the Vickery site is included in the local geology portion of this document.

Faults and folds within the basement rocks can be inferred from the distribution of rock types coupled with gravity, magnetic and seismic data. Figure 5-11 shows that the upper surface of the Precambrian in the western third of Ohio consists of intrusive and extrusive igneous rocks of the East Granite-Rhyolite Province while the surface in the eastern two-thirds of the state consists of Grenville Provence medium grade metamorphic rocks. The Vickery site is located in the Grenville Province approximately 40 miles east of the Grenville Front.

The ECRB is believed to be bounded on the east by the Grenville Front and on the west by block faulting. Gravity and magnetic data suggest the basin is connected to the Midcontinent Rift System in southern Michigan. Figure 5-12 shows the location of the known Midcontinent Rift System. Structural interpretations of seismic data indicate the ECRB predates the Grenville Orogeny and has been partially overridden by the Grenville thrust sheets from the east. The age of the ECRB is somewhat uncertain, but is certainly Proterozoic, and, based on structural relationships, cannot be as young as Cambrian. (Drahovzal, et. al., 1992). Magnetic and gravity data along the ECRB are depicted in Figures 5-13 and 5-14, respectively. The exact extent of the ECRB is uncertain, especially to the north, south and west.

Figure 5-15 shows the regional structural configuration on the top of what was called the Eau Claire by Sherrow in 1987. Figure 5-16 shows the regional structure on the top of the Knox constructed by Janssens (1973)

5.2.2 Stratigraphy

In 1989, drilling of a continuously cored stratigraphic test well by the Ohio Department of Natural Resources, Division of Geological Survey in Warren County has indicated the existence of a thick sedimentary sequence of lithic, conglomeratic sandstone below the Mt. Simon Sandstone. This sequence is named the Middle Run Formation. This sequence is the basin fill of a failed rift valley (the ECRB noted previously). The Middle Run Formation is not present beneath the Vickery site.

The Middle Run Formation was originally described by Shrake et. al. (1990). The formation is very homogeneous at its type location and consists of red to grey, fine to medium grained thickly bedded lithic sandstones. Siltstones and shales generally make up less than 10 percent of the formation volume. The Middle Run is unconformably overlain in most locations by the Mt. Simon Sandstone. Basalt has been identified both within and overlying the sandstones of the Middle Run Formation. (Drahovzal, et. al., 1992)

Figure 5-17 is a partial stratigraphic column depicting the position of the Middle Run

Formation. Figure 5-18 shows the lithology in wells thought to have penetrated the Middle Run Formation.

Cambrian and Lower Ordovician rocks, bound below by the Precambrian and above by the regional Knox Dolomite unconformity, form an extensive deposit on the midcontinent craton. Figure 5-19 shows the generalized stratigraphic correlation chart for Cambro-Ordovician formation across Ohio as derived by Janssens.

The Mt. Simon Sandstone was deposited unconformably across an extensive area on the Precambrian basement surface. The formation or its lithologic equivalents presently extend from the Appalachian Mountains to eastern Missouri, and from Tennessee into Canada. The thickness of the Mt. Simon Sandstone across a four state area is shown in Figure 5-20. Figure 5-21 shows the Mt. Simon Sandstone thickness within the State of Ohio. Within Ohio, the Mt. Simon Sandstone thickness varies from near zero in Pickaway County where it is believed to have never been deposited, to about 400 ft along the state western border. This complex Precambrian surface is not uncommon across Ohio as documented by 20 wells in Ohio drilled into Precambrian paleotopographic highs (Baranoski, 2002)." Based on discussions with staff of the Division of Geological Survey, the Mount Simon Sandstone thins to zero thickness approximately 20 miles southwest of the Vickery facility in Seneca County, Hopewell Township. This observation was made based on the review of sample cuttings and the well log for a well installed in August 1979 (Well Permit #214).

In Ohio, the Mt. Simon Sandstone consists of friable fine to coarse grained sandstone, conglomeratic sandstone and sandy conglomerate. The sand is generally poorly sorted, but individual beds can be well sorted. Medium and larger sized sand grains are usually rounded and frosted. Color ranges from clean to pink or yellowish pink. Dark brownish red staining is present in some locations. The main body of the Mt. Simon Sandstone is poorly cemented, but siliceous cements are noted in some locations.

The Mt. Simon Sandstone is regionally overlain by the Rome Formation (primarily dolomite) in the eastern two-thirds of Ohio and the Eau Claire Formation (primarily glauconitic siltstone and fine grained sandstone), in the western third of Ohio. The middle interval of the Rome contains a sandy facies in the central portion of Ohio, relative to an east-west transect. The Rome and Eau Claire are in a complex facies relationship across Ohio as was shown previously in Figure 5-19. A schematic cross section in central Ohio is presented as Figure 5-22 showing the facies changes within the Rome in a north-south direction. The location of the Vickery facility is shown on Figures 5-19 and 5-22 projected into the appropriate stratigraphic and geographical position to represent the geological conditions encountered at the site. An isopach map of the Rome in northeastern Ohio is presented as Figure 5-23.

From core data obtained at the Vickery site, the sandy unit present in the middle of the Rome contains higher porosity and permeability than do the lower and upper dolomite units. Considerable volumes of core data was provided with the initial Vickery petition submittal.

The Rome-Eau Claire is overlain by the Conasauga Formation, with a variable lithology across the state ranging from sandy dolomite to silty sandstone to red and green shales to limestone. Figure 5-24 is an Isopach map of the Conasauga in northeastern Ohio.

The Kerbel Formation is the fine to coarse grained dolomitic sandstone partially overlying and partially stratigraphically equivalent to the Eau Claire and Conasauga Formations, and underlying the Knox Dolomite across a large area of central Ohio. Figure 5-25 is an Isopach map of the Kerbel in northern Ohio.

The name Knox Dolomite is applied to the dolomite overlying the Eau Claire, Kerbel and Conasauga Formations, and underlying the regional Knox Dolomite unconformity. The

Knox Dolomite in Ohio consists of dolomite, sandstone and stratigraphically restricted limestone. The formation thickness is significantly affected by a regional unconformity which occurs at approximately the lower Ordovician -Middle Ordovician boundary (The Cambrian - Ordovician Systemic boundary occurs on top of the Knox Dolomite at the Vickery facility). Figure 5-26 is an Isopach map of the Knox in Ohio.

The Knox Dolomite is overlain by basal Middle Ordovician dolomites and clastics of the Wells Creek Formation. The Wells Creek often consists of green shale and siltstone, but may locally contain sandstone or argillaceous sandy dolomite.

The Black River Group is composed of argillaceous, micritic, burrowed limestones, micritic limestone with dolomite filled burrows in the middle third and interbedded micritic and pelletal limestone and fine grained dolomite. The upped one-third of the formation contains a series of relatively thin beds of bentonitic shale or argillaceous or bentonitic limestone.

The contact between the Black River and the overlying Trenton Limestone is usually picked at a prominent bentonite bed since the lithographic limestones of the upper Black River are not distinguishable from the medium to finely crystalline Trenton Limestone using geophysical logs. Sample examination is usually required for an exact correlation.

The name Cincinnatian Series, a time-stratigraphic term, is restricted to rocks of Late Ordovician age. Most of the "formations" assigned to the Cincinnatian Series are actually biostratigraphic zones. The series consists of thinly interbedded shales, limestones and siltstones. An erosional unconformity marks the upper boundary of the Cincinnatian Series and marks the approximate systemic boundary between the Ordovician and Silurian.

The Cataract Group, consisting of the Brassfield Formation (locally) (known as the Manitoulin Dolomite in this part of northern Ohio) and the Cabot Head Formation were deposited in ascending order above the unconformity. The Manitoulin Dolomite consists generally of dolomitized coarse grained limestone which grades upward into interbedded green and reddish-brown shale and dolomitized coarse grained limestone which makes up the Cabot Head Formation.

The Cataract Group is overlain by the Dayton Formation which is composed of two thin dolomitized limestones which may be locally separated by a green shale member. The Dayton is in turn overlain by the Rochester Formation which may be a green, gray, and dark brown shale or argillaceous dolomite.

The Lockport Group overlies the Rochester Formation. The Lockport, in ascending order, may be composed of crinoidal gray dolomite; a finely crystalline brown dolomite which may contain chert; and a coarsely crystalline vuggy gray and white dolomite.

The Lockport is in turn overlain by the evaporite sequence of the Salina Group. In the eastern portions of Ohio, the Salina may be differentiated into distinct lithologies more readily than in the central or western areas of the state.

The limestones, dolomites and evaporites which overlie the middle Silurian Rochester Shale, and underlie the Middle Devonian Ohio Shale are often collectively referred to as the Big Lime. The Big Lime is present across much of Ohio, and where it is at or near the surface along the Findlay Arch forms an important aquifer.

An erosional surface of Silurian sedimentary units form the bedrock surface beneath the Vickery site. To the east of the Vickery facility and down-dip structurally from the Findlay Arch, younger aged Paleozoic sedimentary units are present in the subsurface. These units are not present at the Vickery site, either due to non-deposition or post deposition erosion.

gentle east dip on the flank of the Findlay Arch. No significant odor or fluorescence was noted in samples when drilling the waste injection wells. No odor or fluorescence was noted within any unit of the injection interval, however a minor non-commercial hydrocarbon show was observed at the Knox unconformity during drilling of Well No. 1.

During the installation of the Knox-Kerbel Well in 1993, a standard oil field gas chromatograph was in operation monitoring the return drilling mud flow. The highest concentration of gases detected by this instrumentation was encountered between 262 and 280 feet md, near the top of the Lockport Formation within the Big Lime. A maximum of 720 Total Gas Units and 38,700 ppm methane was recorded. At deeper drilling depths, the gas content of the return mud stream rarely exceeded 20 Total Gas Units. At the top of the Trenton Formation, there was no increase in gas noted when this formation (which has historically been a producer of gas and oil in northwestern Ohio) was penetrated. There was also no mud gas increase noted when the Knox Dolomite or Kerbel Formation were penetrated. Due to the lack of significant hydrocarbon shows in the well, no drill stem tests were scheduled or performed. This failure to encounter any commercial hydrocarbon shows in the well collaborates the findings from the previous drilling of the injection wells at the site. Results of the monitoring during installation and an in depth study of the cores concluded that there was no evidence of commercial hydrocarbons.

A reflection seismic program was shot by Vickery within the AOR. A broad anticline feature exists beneath the facility in the Precambrian basement diminishing in amplitude upward through Ordovician age Trenton Formation units. This feature has the potential for the accumulation of hydrocarbons; however, commercial hydrocarbon accumulation has not been found. It appears that the likelihood for the existence of commercial hydrocarbons within the AOR is remote as supported by the previous paragraphs above.

Sand, gravel, limestone and gypsum are commonly quarried in portions of northern Ohio. No mines, quarries, sand or gravel pits are known to exist within the AOR. Figure 5-34 shows the location of sand and gravel quarries and limestone and dolomite quarries in and near Sandusky County. No quarrying operations are within the AOR.

5.5 GEOLOGY OF THE VICKERY SITE

5.5.1 Structure

The Geology of the Vickery site was extensively evaluated when the facility submitted its initial petition, and is summarized here. There has been no drilling activity within the AOR that has impacted the interpretation of the subsurface geology since the initial petition was prepared.

The Vickery site is located east of the crest of the Findlay Arch. Figure 5-35 is a sub-regional structure map on the top of the Trenton Limestone showing the location of the facility on east-southeast dip of approximately 40 ft per mile.

The stratigraphic column of the geology within the AOR was previously illustrated in Figure 5-2. A series of structure maps were constructed within the AOR using the relatively sparse subsurface control available. Figures 5-36 and 5-37, included here, are reductions of maps on top of the Cincinnatian and Mt. Simon Sandstone, respectively. They are representative of the structure within the AOR.

Figure 5-38 is an enlargement from Baranoski's 2002 interpretation mapping the Precambrian unconformity showing the structure in the vicinity of the Vickery facility. The locations of the reflection seismic lines that were shot by Vickery in 1989 as a portion of preparing the initial USEPA no-migration demonstration are shown on this map. Excerpts from the report compiled by Weston Geophysical from their analysis of the data are included below. Attachment I includes the results of the seismic study performed at the facility in 1989 and provides additional information on the geology of the facility.

> *Overall, the 59 miles of seismic reflection data, obtained within a 5 mile radius of the Vickery site, are consistent with the gently southeastward dipping Precambrian unconformable surface overlain by the relatively uniform, Early Paleozoic sedimentary units. Superimposed on the regional southeastward dipping surface,*

a low relief anticline trends north-south beneath the Vickery site. Time structure and isochron and depth converted structural contour and isopach maps of the Precambrian surface and the Mt. Simon, Rome and Trenton units, indicate localized sediment thinning and thickening, predominately within the Mt. Simon, due to nondeposition and/or erosion and filling over paleotopographic relief. Slight arching of the interpreted formations suggests minor intermittent uplift.

The primary feature of interest, revealed in examination of the seismic reflection profiles and delineated on the Precambrian structural contour map, is a broad north-south trending high superimposed on the regional southeastward dipping surface. The main component of the topographic high is approximately 2 miles wide and extends north-south at least 5 miles. However, the outline of the elevated surface is irregular, with subordinate lobes extending 2 miles to the northeast and 1.5 miles to the west of the main trend beneath the site the maximum relief on the feature is approximately 120 feet measures on the Precambrian surface.

The Mt. Simon unit (Mt. Simon Thickness map) locally thins and thickens corresponding to paleotopographical relief on the Precambrian surface (Precambrian Surface map). This effect is apparent over the principal structural high as well as several other less extensive flexures of both positive and negative relief. Sediment thickness variations are attributed to variable deposition and erosion events in a shallow marine transgressive environment over the irregular Precambrian surface.

The Mt. Simon Formation thins by approximately 60 feet, directly over the broad Precambrian paletopographic high beneath the site, indicating that a certain amount of relief was present prior to and during Mt. Simon deposition. However, it is evident that the total relief presently observed at this location on the Precambrian surface (Precambrian Structure map) could not have been present *during Mt. Simon deposition. A Precambrian erosional remnant of that magnitude (120 feetA0 would have remained exposed above seal level in the shallow intertidal marine environment indicated for initial plaeozoic deposits, presumably resulting in nondeposition, of the Mt. Simon sandstone.*

The next prominent reflection horizon above the Mt. Simon is the top of the Rome Formation, caused by the contrast of Upper Rome dolomite in contact with sandstone of the Conasauga Formation. The top of the Rome is the most consistent horizon of the four mapped in this study. The structural contour map of the Rome surface is consistent with other mapped horizons, showing a broad north-south trending anticline superimposed on the regional southeastward dip.

The interval between the top of the Rome and Trenton reveals no consistent reflection horizons. The youngest consistently usable marker horizon is the Trenton. Structural contour mapping of this formation (Trenton Structure) reveals a flexure over the principal structure high beneath the site, consistent with but of less amplitude than those detected below. The isopach map for the interval between the Trenton and the Rome formations shows no appreciable thinning over the structural high beneath the site indicating that the Precambrian paleotopographic relief did not significantly influence sediment deposition at this level.

The deformation associated with formation of the structural high beneath the site is a relatively minor response to regional tectonic movements influencing the Findlay Arch and adjacent basins. The absence of any abrupt discontinuities in the Paleozoic horizons or evidence for brittle deformation in the Precambrian basement, penetrating into overlying Paleozoic units, indicates that episodic formation of the broad feature occurred slowly in a nonbrittle manner perhaps over substantial lengths of geologic time.

No faulting has been detected in wells within the AOR through log correlations. The series of structure maps which were constructed generally showed east-southeast dip except where interrupted by the gentle structural nose near the facility.

The correlation of the wells within the AOR is relatively clear-cut and leaves little margin for subjective judgment. The waste disposal wells at the site are closely spaced and correlate with each other in a very consistent manner, leaving little possibility that faulting exists.

Figure 5-39 is a stratigraphic cross section utilizing actual electric logs at a vertical scale of 1" = 100 feet within the Vickery AOR. This cross section shows that excellent correlation of the units across the area. Figure 5-40 is a schematic structural cross section across the AOR showing that southeast dip component present in all maps of the area. Figure 5-40a is a stratigrahphic cross section showing the very good subsurface correlations between the Vickery site and a deep well in northwestern Seneca County, about 15 miles to the southwest of Vickery.

5.5.2 Stratigraphy

The stratigraphy at the Vickery site was derived from well logs and descriptions of drill cuttings and cores. Figure 5-1, previously presented, showed the stratigraphic column at Vickery and identified the injection and confining zones.

Over a period of almost 20 years Vickery has performed numerous studies on cores recovered from the site injection wells. Earlier studies focused mostly on lithology, porosity, permeability and compatibility of the formation materials with the injected wastes. Later studies concentrated more on evaluating the depositional environments and diagenesis of the formation through both megascopic and microscopic examinations in additional to physical properties. A comprehensive core study performed in 1989 (included in the Vickery petition as Appendix P) evaluated approximately 800 feet of core. This study indicates that there have been multiple episodes of cementation, dissolution, and diagenesis in all of the Precambrian through Knox cores evaluated. Minor fracturing was observed in the cores from the Mt. Simon, Rome, Conasauga, Kerbel and Knox Formations. No displacement was observed in the stabbed cores or in thin sections made in the fractures intervals. Most fractures were discontinuous due to cement fill. These were interpreted as natural fractures affected by post depositional diagenesis. Some fractures that did appear continuous were sharp clean break that showed no evidence of any cementation or dissolution. These open fractures were interpreted as having been induced by the coring operation and were not representative of the actual formation conditions.

Within the AOR, the Precambrian basement was reached at depths ranging from 2884 ft (-2266 ft) in Disposal Well No. 3 to 3092 (-2441 ft) in the East Ohio Gas company No. 1 Haff. Basement samples from the No. 1 Haff were described by McCormick (1961), who determined the Precambrian at that location to be medium grained granite composed of pink orthoclase and quartz, with accessory biotite and plagioclase.

Within the Vickery facility, the basement encountered in Disposal Well No. 1 is described megascopically as dark reddish brown, fine to medium grained, equigranular rock composed of potassium feldspar, plagioclase, quartz and biotite with a well defined foliation produced by sub-parallel orientation of biotite flakes. Microscopic examination of thin sectioned material indicated a composition of quartz 31.9%, microcline 34.1%, plagioclase 27.4%, biotite 4.8%, perthite 1.3% and accessory minerals 0.5%.

Cuttings samples from Disposal Wells No. 2, No. 3 and No. 4 at the site were described as light orange to red granite with biotite, by the well site geologist. Granite and gneiss are compositionally similar, and it is possible that foliation was present in the samples but not observable due to the small size of the cuttings. A thin section taken from 2926.7 ft measured depth in Disposal Well No. 1 was described as a massive, alkali granite. Crystal size ranged from .09 to 1.9 mm, averaging .53 mm. The subequant to elongate crystals consisted of 38% quartz, 31.6% K-feldspar, 26% plagioclase, 2.4% biotite, 1.6% hornblende, .4% other minerals. Microfractures were partially filled by chloritic clay minerals. No metamorphic minerals or textures were observed.

The Vickery facility is located within the transition zone between the Grenville and East Granite-Rhyolite Province provinces as plotted by Lucius (1988), and variable lithologies are to be expected within this zone.

During February, 1990, Vickery performed additional petrographic studies on cutting samples from Disposal Wells Nos. 2 and 3, which were on file with the ODNR. The purpose of the work was to determine the depth at which the Precambrian basement was penetrated. The study indicated that in Well No. 3, Precambrian granite was encountered at a measured depth between 2890 and 2900 ft. From geophysical logs, the top was previously picket at 2884 ft measured depth (-2266). The Precambrian positive structure feature beneath the No. 3 well is therefore confirmed by the cutting petrography.

In Well No. 2, no Precambrian igneous lithology was noted in the cutting petrographic study. Previous cuttings descriptions placed the Precambrian at 2930 ft measured depth (-2314). This depth (2930) did not agree with geophysical logs run in the No. 2 well and was not utilized in structural mapping for the site. Instead, a Precambrian top of 2950+ ft measured depth (-2334+) from geophysical logs was used for mapping purposes. This places the Precambrian very near the bottom of the well. The petrographic study indicates that even this top is structurally to high. It is believed that the Precambrian must be quite close to the bottom of the No. 2 well, based on the close proximity of a good control point in the No. 1A well.

In 1993, the Knox-Kerbel monitor well was installed approximately 90 feet northeast of the No. 2 injection well. Prior to drilling, it was anticipated that the monitor well would encounter geological formations in a structural position and with thickness very similar to that found in the No. 2 injection well. This pre-drilling concept proved to be correct, and there was an excellent correlation between the two wells. Table 5-3 presents the structural and stratigraphic relationship of the monitor well compared to the No. 2 injection well. The Knox-Kerbel monitor well actually ran about 1.5 to 6.5 feet low structurally relative to mean seal level datum versus the No. 2 injection well. At shallower depths, the monitor well was slightly thin to the No. 2 well, but all comparable formation thicknesses varied by not more than 2 feet.

In Seneca County, approximately 15 miles southwest of the site and 10 miles outside the AOR, the Ohio Division of Geological Survey continuously cored the No. 1 M. and B. Asphalt Company well from the upper surface of bedrock into the Precambrian. At this location, the Precambrian was a dark green to black gabbro with fractures filled with dark red and medium green materials of undermined mineralogy (Wickstrom et.al., 1985). This well was drilled near the center of one of the largest gravity and magnetic anomalies in Ohio, an area from which amphibolite has also been reported from the basement (Lucius, 1988), and falls within the transition zone between the Grenville and East Granite-Rhyolite Province.

The injection interval, the Mt. Simon Sandstone, unconformably overlies the Precambrian basement. The Mt. Simon Sandstone ranges from 147 ft to 84 ft in thickness for wells within the AOR, and has an average thickness of about 122 ft. Variation in thickness is largely controlled by relief on the Precambrian surface. Figure 5-41 is an isopach (isochore) map of the thickness of the Mt. Simon. This map is based solely on well control, and shows all dashed contour lines due to the uncertainty of the formation thickness away from the control points. Thickness represented on this map inside the AOR ranges from slightly leass than 100 feet to just over 150 feet. Figure 5-42 is an Isopach map drawn by Weston Geophysical using the 59 miles of seismic data shot by

Vickery in the AOR. This map generally indicates a Mt. Simon thickness from just under 100 feet to just over 100 feet, except to the west of the facility one to three miles where the thickness is shown to reach as much as 200 feet.

The Mt. Simon Sandstone is composed of moderately to well sorted, very fine to coarse grained sandstone. These sands contain low quantities of detrital clay, but authigenic grain-coating chlorite is fairly common. Dolomite cement and interbedded dolomites are sporadically distributed through the sandstones. Additional information on mineralogy, texture and lithology are provided in Attachment C.

The containment interval at Vickery consists of the Rome, Conasauga, Kerbel Formations and Knox Dolomite. This interval consists of approximately 440 ft of dolomites and sandstones and acts as a barrier to waste movement out of the Mt. Simon Sandstone (injection interval). The thickness, lithology, texture and depositional environment of each formation is discussed in Attachment D.

The confining zone is composed of the Wells Creek and Black River Formations. These formations consist of limestones and shales approximately 545 ft in total thickness. Information about these formations is provided in Attachment E.

5.5.3 Base of Lowermost USDW

The lowermost USDW beneath the Vickery site is the Lockport Formation. While log calculations indicated the Manitoulin Dolomite(Brassfield) had TDS in excess of 10,000 ppm equivalent NaCl and the Lockport Dolomite has TDS concentrations less than 3000 ppm equivalent NaCl, during the installation of the lowermost USDW monitoring well at the site, the Manitoulin Dolomite did not produce sufficient quantities of fluid. Therefore, the Lockport Formation was selected as the location of the monitored interval for the subsequently drilled Lockport monitoring well, and the Lockport base at 574 feet measured depth is considered as the base of the USDW.

In the Vickery area of Sandusky County, the Lockport Dolomite is considered as a formation rather than a "group", due to the inability to differentiate it into the stratigraphic units identifiable in some other portions of Ohio. The Lockport and the undifferentiated Salina Group comprise what is known by the drillers term "Big Lime" in this area. The Big Lime is a major source of ground water in Sandusky County, especially for livestock and agricultural purposes. The existing ground water contains high amounts of sulfate materials primarily derived from gypsum and anhydrite units within the Salina Group. This high dissolved mineral content renders much of the ground unusable for human drinking purposes.

Vickery has an active groundwater monitoring program which involves monitoring of the Knox-Kerbel Formations, and the Lockport Formation. Figure 5-43 shows the distance of the wells from Well No. 2. The monitoring program for the Knox-Kerbel includes continuous monitoring of the reservoir pressure within the lower Knox Dolomite and upper Kerbel Formation and annual sampling of the interstitial fluids from the Knox-Kerbel zone. The Lockport Monitor well is sampled on an annual basis. This program has been ongoing since 1993 and has confirmed that the waste is not migrating out of the injection zone and that pressurization of the subsurface formations is consistent with that predicted by the SWIFT model prepared for the no-migration petition. The modeling simulation, utilizing conservative petrophysical and well operating parameters as input, predicted as much as a 60 psi increase in the Knox-Kerbel interval. The monitored formation pressure in the Knox-Kerbel interval has remained within these conservative control limits, indicating no excess pressurization due to injection activities. Twenty-five years of monitoring the formation fluid chemistry from the Knox-Kerbel has demonstrated relatively little change in the composition of the fluid. Detailed reports which include the results of the Knox-Kerbel and Lockport monitoring program have been submitted to the Ohio EPA periodically, as required.

Table 5-4 shows the most recent chemical sampling data from the Lockport well from April 2017. DWFF1, DWFF1D, and DWFF1B are the samples, supplicates and a field blank, respectively. Table 5-5 shows the chemical results for the sample from 1993-2017, indicating relatively little change with time.

Table 5-6 shows the most recent chemical sampling data from the Knox-Kerbel well, April 2017. Sample KKFF1, KKFF1R and KKFF1B are the sample, replicate and a field blank, respectively. Table 5-7 shows the chemical results for the Knox-Kerbel well from 1993-2017, indicating relatively little change with time. The baseline period for chemistry data from the Knox-Kerbel well was the initial eight (8) quarterly sampling events, after which the well was switched to an annual sampling schedule.

Figure 5-44 shows the pressure data from the Knox-Kerbel monitor well from April 2012 through April 2017 and corresponding injection pressure in injection Well No. 2. The step like appearance of the data is due to changes in measure specific gravity, which is utilized in calculating the formation pressure at the reference depth, with the steps occurring at the sampling events. There has been no increase in monitored formation pressure due to injection activities at the Vickery site. The baseline period for pressure measurements was the five (5) quarters of pressure data measured from January 18, 1994 through April 10, 1995, excluding the first fifteen days of data immediately following a sampling event to allow for formation pressure recovery. The first two (2) quarters of monitored pressure data (July 9, 1993 through January 17, 1994) were excluded from the baseline data due to significant variations in measured specific gravity for the formation fluid.

10.0 CHARACTERISTICS OF THE INJECTION ZONE

10.1 Introduction

The criteria for siting of hazardous waste injection wells codified in 40 CFR, Part 146.62 (C)(1), requires that the injection zone has sufficient permeability, porosity, thickness and areal extent to prevent migration of fluids into USDWs.

The injection zone is defined in 40 CFR, Part 146.3 as a geological formation, group of formations, or part of a formation receiving fluids through a well. The injection of hazardous waste can only take place below the lowermost formation containing within 1/4 mile of the well bore, a USDW. Vickery has separated the injection zone into an injection interval, into which actual emplacement of waste fluid occurs, and a containment interval which includes the layers above the injection interval where vertical fluid movement will be contained.

The following subsections describe the injection intervals suitability for injection of hazardous waste and the containment intervals properties which make it capable of limiting fluid movement out of the injection zone.

10.2 Injection Interval

10.2.1 Lithology, Reservoir Thickness

The permitted injection interval for the Vickery waste disposal wells is the Mt. Simon Formation, a Cambrian age sandstone. The Mt. Simon averages slightly over 121 feet in thickness, with minimum and maximum recorded thickness of 84 and 147 feet respectively from wells within the AOR. The formation is composed of moderately to well sorted, very fine to coarse grained sandstones. Quartz and K-feldspar are the primary framework grains. These sandstones contain low quantities of detrital clay, but authigenic grain coating chlorite is fairly common. Dolomite cement and interbedded dolomite zones are sporadically distributed throughout the formation. Detailed data concerning lithology of the injection interval is found in Attachment C.

10.2.2 Porosity and Permeability

Porosity is a measurement of how much void space is available for fluids to occupy within a volume of rock, generally expressed as a percentage. Permeability is a measurement of the capacity of a material to transmit a fluid under the influence of a pressure differential. A standard unit of permeability measurement is the darcy, which

TABLE 10-1

MT. SIMON POROSITY AND PERMEABILITY TO AIR

		Total Mt. Simon Thickness	Top 30 Feet
WELL #1*	N	89	21*
	K_h(md)	36.09	24.26
	ϕ_h(%)	15.06	14.53
	N	89	21*
	K_v(md)	.0086	.29
	ϕ_v(%)	NA	NA
WELL #4	N	93	30
	K_h(md)	62.08	98.06
	ϕ_h(%)	12.65	14.97
WELL #5	N	132	30
	K_h(md)	32.01	60.98
	ϕ_h(%)	13.63	13.60
3 WELLS OVERAGED	N	314	81
	K_h(md)	42.07	65.19
	ϕ_h(%)	13.75	14.35
	N**	89	21*
	K_v(md)	.0086	.29
	ϕ_v(%)	NA	NA

* Upper 9 ft of Mt. Simon was not cored
** Only from #1 Well
N Number of samples
K_h Arithmetic mean
K_v Harmonic mean
ϕ_h Arithmetic mean

is defined as the flow of one cubic centimeter per second of a fluid with viscosity of one centipoise through a porous medium having a cross sectional area of one square centimeter and length one centimeter, under a pressure differential of one atmosphere. As a practical matter, measurements are usually expressed in millidarcies (md), where one millidarcy = .001 darcy.

There have been many different studies performed on the Vickery wells over a period of more that 20 years. The following is a summary of porosity and permeability data. The reader is referred to the original petition document, and to Appendix A of this document which specifically summarizes flow through testing and petrographic tests that were completed after the original petition was submitted. The full report of these tests were previously submitted to the USEPA and ODNR.

Porosity and permeability of the Mt. Simon at Vickery were obtained through plug and whole core analysis of cores from Disposal Wells Nos. 1, 4 and 5. The arithmetic mean horizontal permeability to air in the 3 cored wells was 42.1 md (314 samples), and ranged from <.0001 md to 730 md. One sample in the No. 5 well tested for horizontal permeability at 50 md in one direction and 3037 md at 90 degrees to that direction. This extremely high value is believed to have been caused by induced fracturing of the sample, and is not reliable. The harmonic mean vertical permeability to air as measured in the No. 1 well was .0086 md, and ranged from <.0001 md to 163 md, (89 samples). Porosity in the three cored wells averaged 13.75 percent, and ranged from 2.9 to 22.8 percent, (314 samples).

Within the top 30 feet of the Mt. Simon in the three cored wells, horizontal permeability to air averaged 65.2 md and ranged from <.1 md to 730 md. Porosity averaged 14.4 percent and ranged from 2.9 to 22.8 percent. The significance of this above average permeability and porosity will be explored in greater detail later in this section, and in the modeling section. Table 10-1 summarizes the porosity and permeability to air data for the Mt. Simon.

Figure 10-1 represents the horizontal permeabilities from Disposal Wells Nos. 1, 4 and 5 as measured in cores at one foot intervals, and demonstrates the lateral continuity of the permeability zones across the Vickery site.

Figures 10-2, 10-3 and 10-4 compare core measured permeabilities to the bulk density logs through the corresponding intervals. There is a good to fair correlation of the

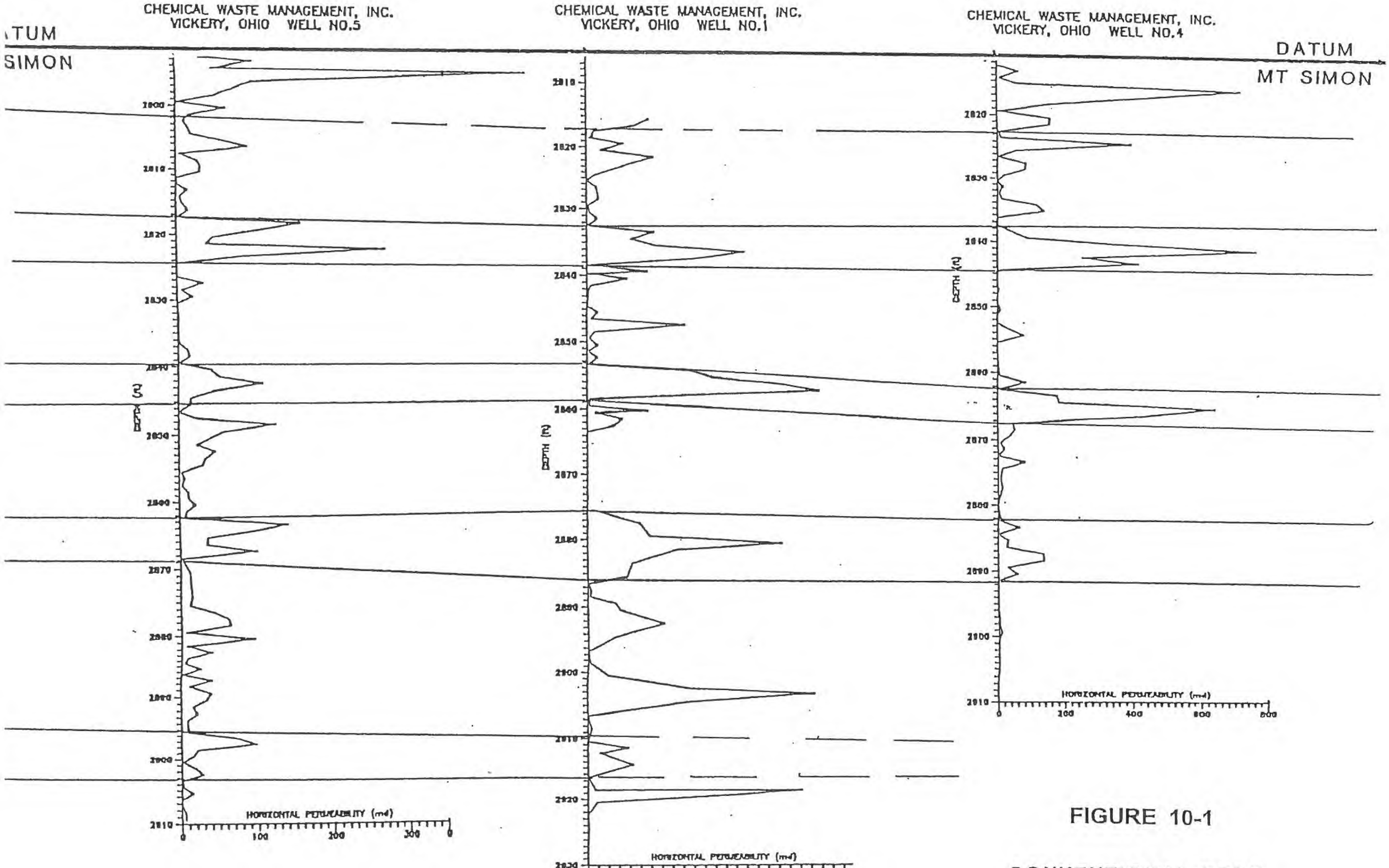
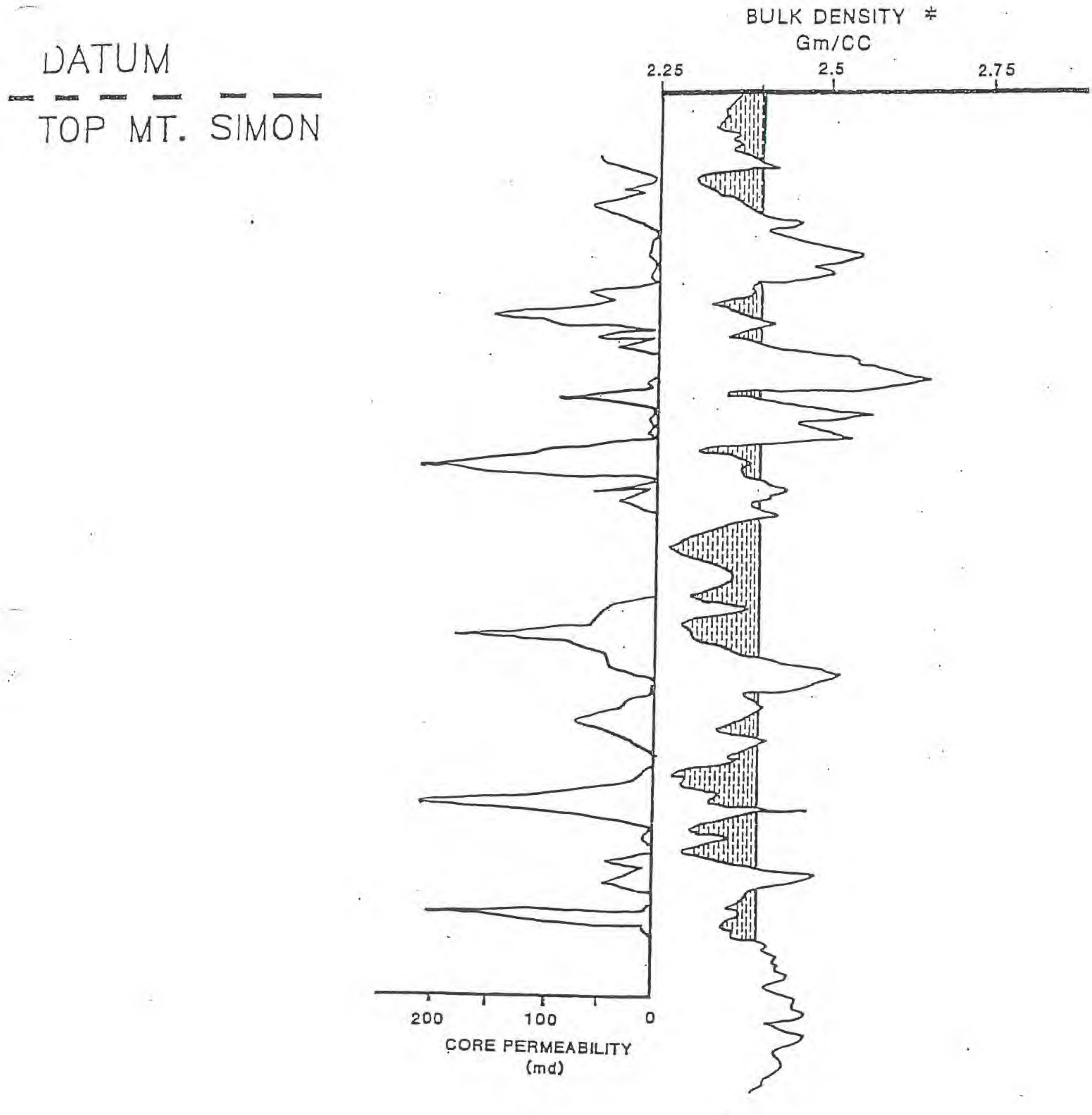


FIGURE 10-1

CONVENTIONAL CORE

PERMEABILTY CORRELATION

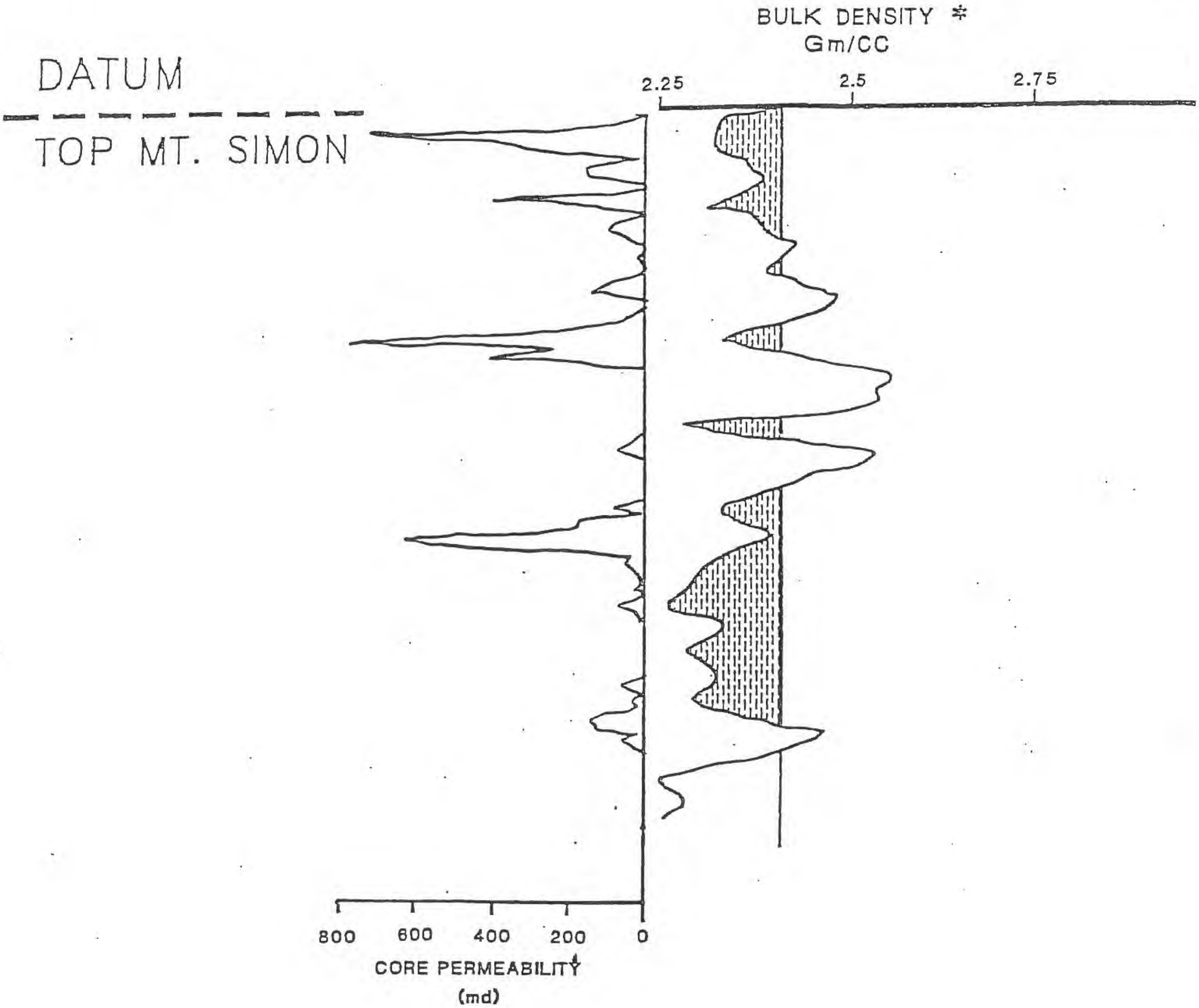


20'

ZONES WITH POROSITY
> 15%, ASSUMING
MATRIX DENSITY = 2.68 GM/CC.

* FROM SCHLUMBERGER COMPENSATED
FORMATION DENSITY LOG RUN 3/17/72.

DISPOSAL WELL NO. 1
CORE PERMEABILITY VS.
BULK DENSITY



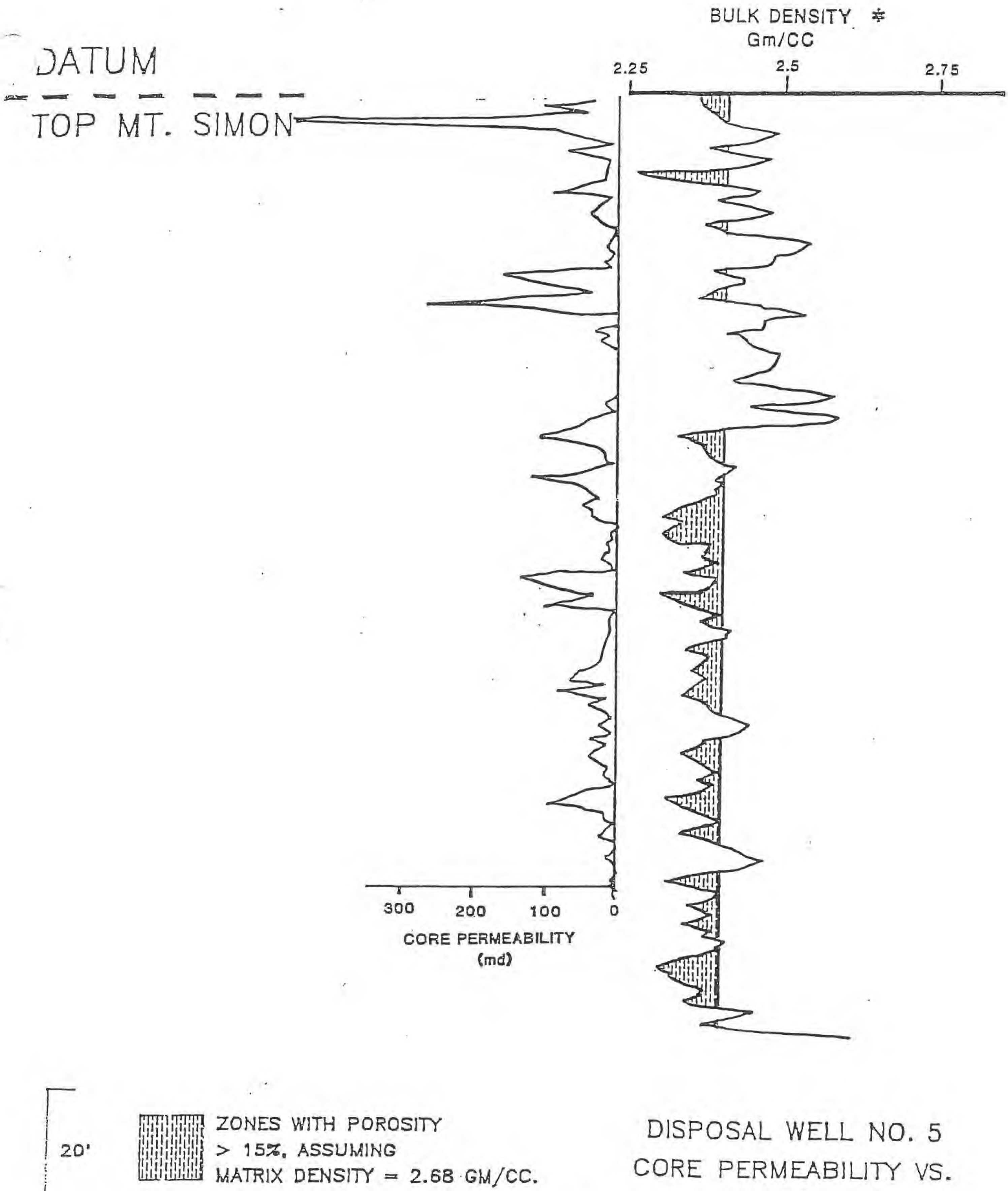
20'

ZONES WITH POROSITY > 15%, ASSUMING MATRIX DENSITY = 2.68 GM/CC.

* FROM BIRDWELL DENSITY BOREHOLE COMPENSATED LOG RUN 7/29/76.

DISPOSAL WELL NO. 4
CORE PERMEABILITY VS
BULK DENSITY

FIGURE 10-3



* FROM SCHLUMBERGER COMPENSATED NEUTRON-FORMATION DENSITY LOG RUN 11/15/80.

DISPOSAL WELL NO. 5
CORE PERMEABILITY VS.
BULK DENSITY

FIGURE 10-4

porosity zones represented on the density logs with the permeabilities obtained from core measurements.

The effect of relatively low relief Precambrian topography on the containment capabilities of the injection zone is expected to be negligible. It will be demonstrated later in this section that most of the injected waste goes into the uppermost portions of the Mt. Simon. These zones are continuous across the Vickery site and are not affected by Precambrian topographic relief.

Porosity vs permeability (>.1 md) cross plots for Disposal Wells Nos. 1, 4 and 5 are shown in Figures 10-6, 10-7 and 10-8. Combined data from all three wells are represented in Figure 10-9. There is generally fair correlation between porosity and permeability within the Mt. Simon. Data scatter is thought to be largely due to the presence of variable amounts of quartz and dolomite cement, and argillaceous materials.

10.2.2.1 Porosity Development and Diagenesis

The Mt. Simon consists largely of sandstones with high textural variability and dolomite beds which appear to have formed by diagenetic replacement. Sandstones with the highest porosity development are generally well sorted, clay-poor, fine to medium grained sand that are relatively free of pore filling dolomite cement.

The diagenetic alteration of these sandstones began with moderate burial compaction which was then succeeded by the formation of grain-coating chlorite, quartz overgrowth cements (followed closely by K-feldspar overgrowth cement), and followed in turn by the

FIGURE 10-6

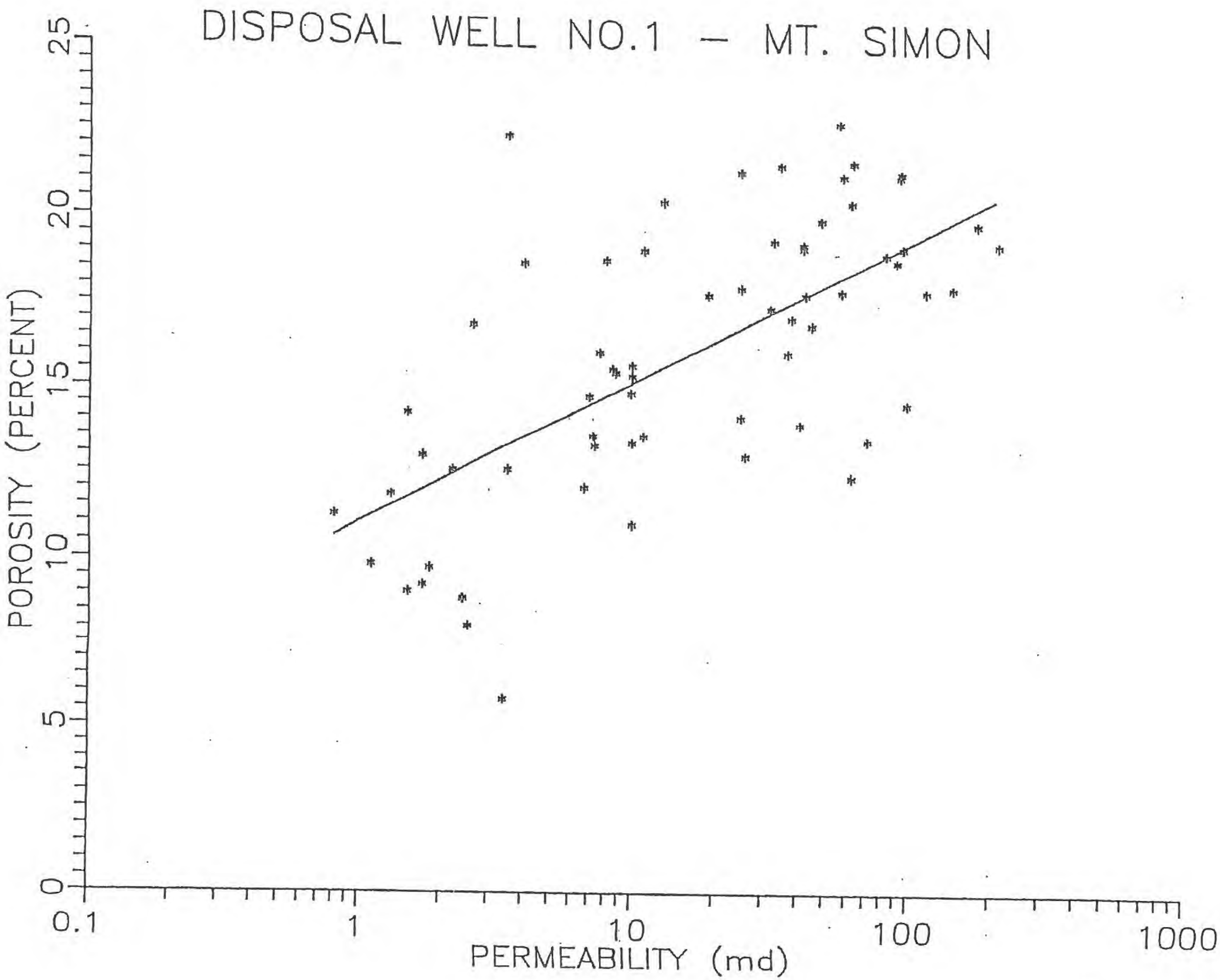

DISPOSAL WELL NO.1 — MT. SIMON
POROSITY (PERCENT)
25
20
15
10
5
0
0.1
1
10
100
1000
PERMEABILITY (md)

FIGURE 10-7

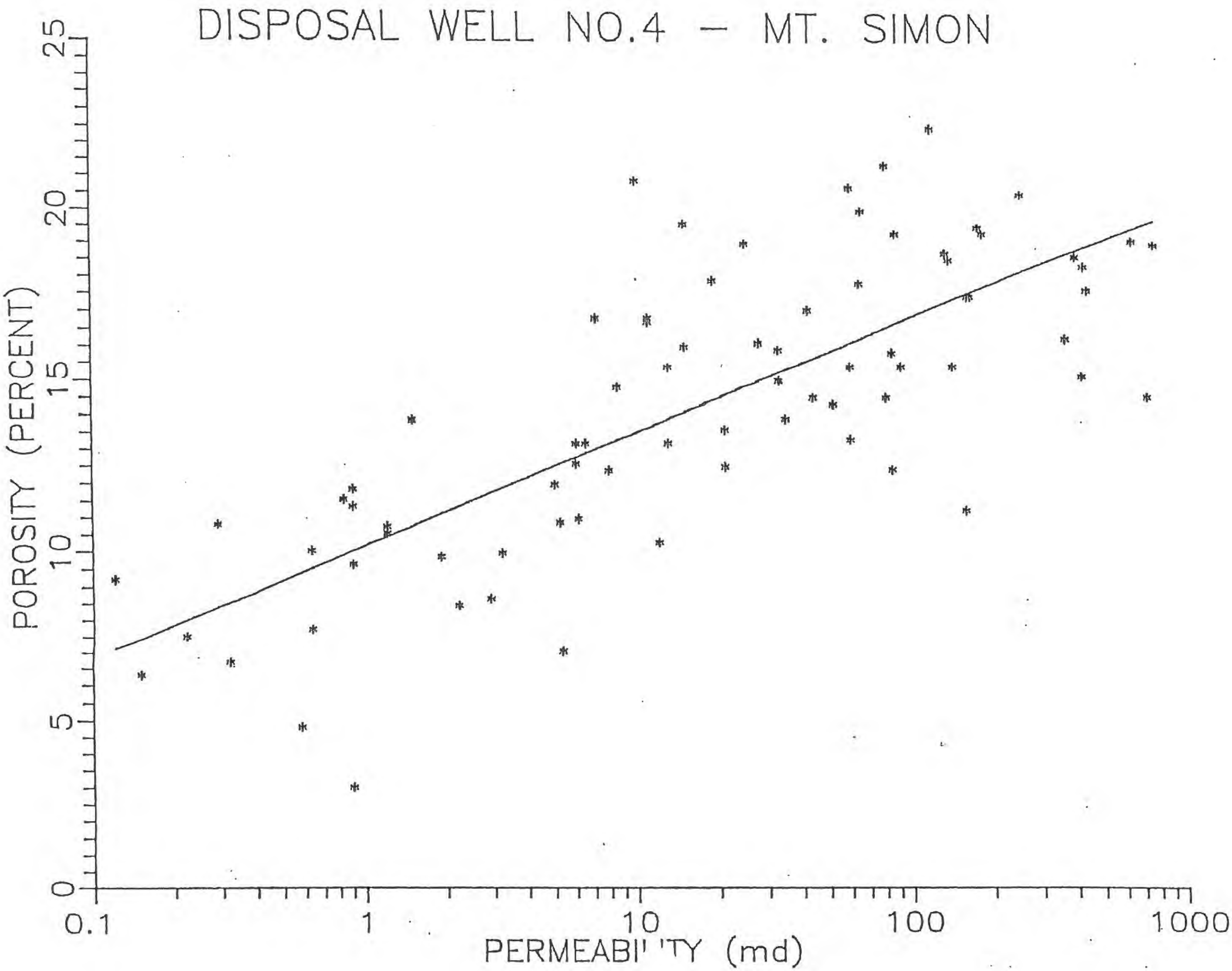

DISPOSAL WELL NO.4 – MT. SIMON
POROSITY (PERCENT)
0
5
10
15
20
25
0.1
1
10
100
1000
PERMEABI' 'TY (md)

FIGURE 10-8

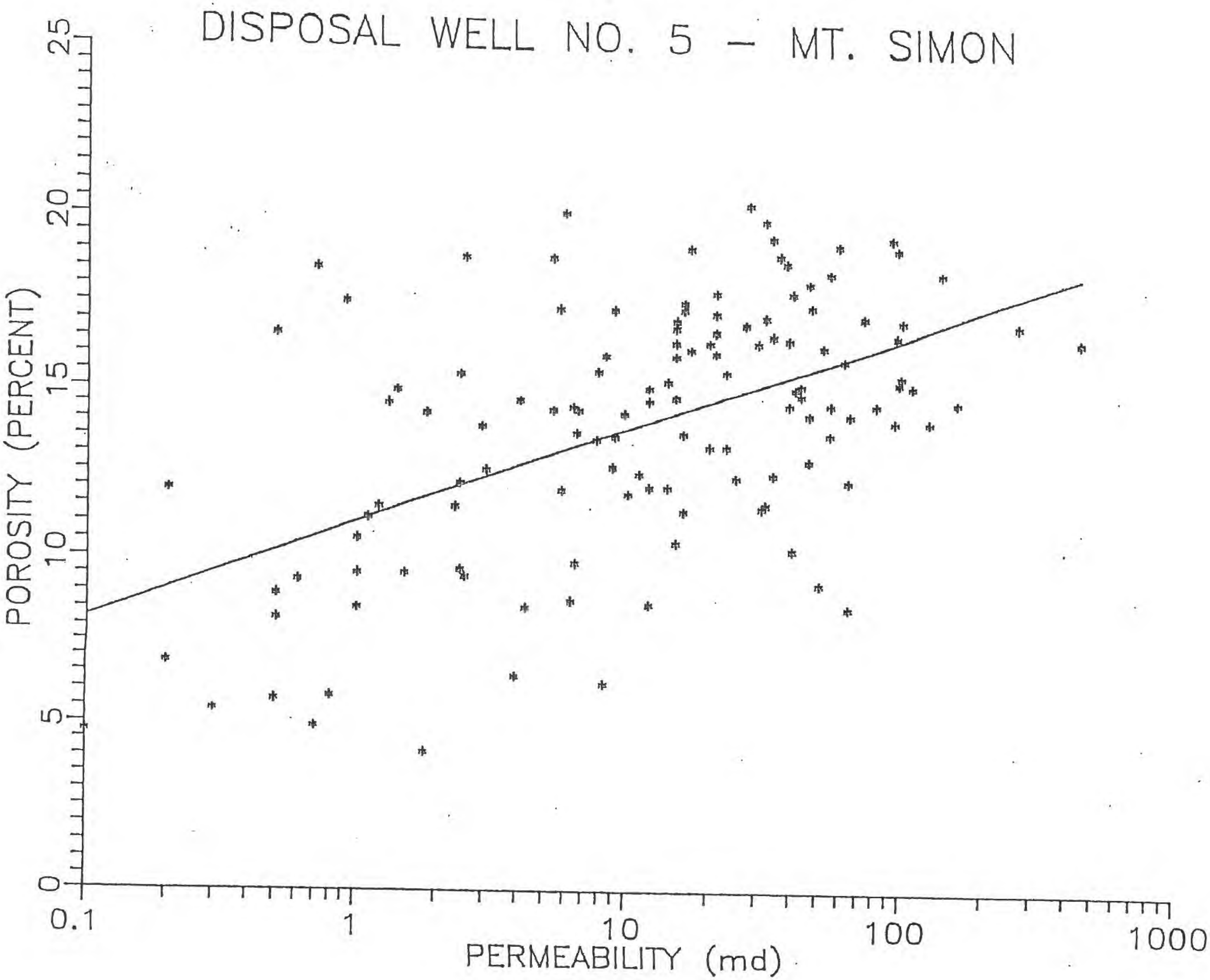
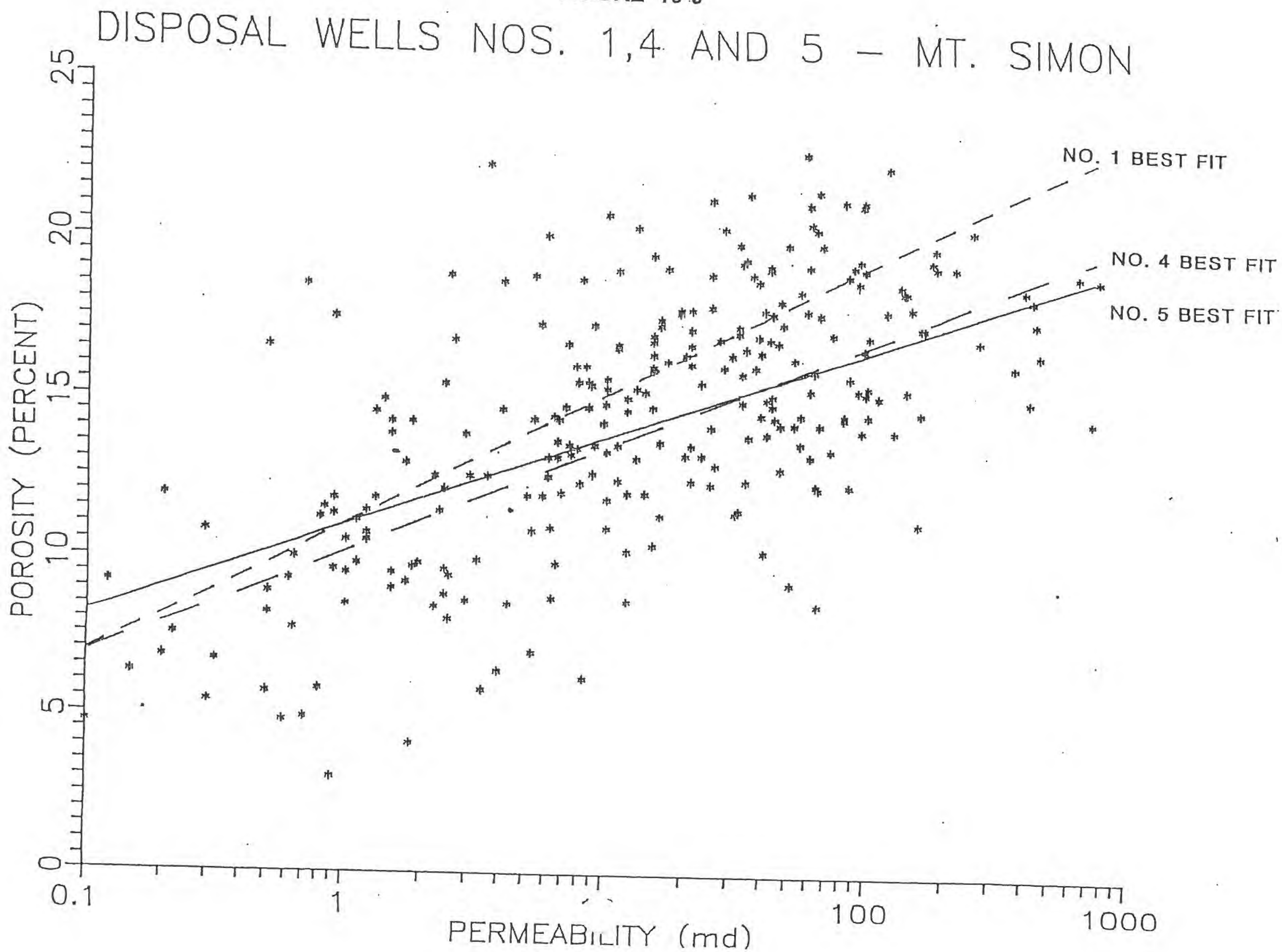

DISPOSAL WELL NO. 5 — MT. SIMON
POROSITY (PERCENT)
PERMEABILITY (md)
0
5
10
15
20
25
0.1
1
10
100
1000

FIGURE 10-9



DISPOSAL WELLS NOS. 1,4 AND 5 – MT. SIMON
NO. 1 BEST FIT
NO. 4 BEST FIT
NO. 5 BEST FIT
POROSITY (PERCENT)
25
20
15
10
5
0
0.1
1
100
1000
PERMEABILITY (md)

dissolution of unstable detrital grains (largely feldspar). Dissolution porosity was followed by a second phase of quartz cementation, the development of authigenic illite (which occurs in small amounts), and rare pyrite cement. An earlier, sometimes extensive episode of dolomite cementation, was recognized in some beds, especially beds rich in carbonate particles (i.e. ooids, peloids). This episode appears to have occurred shortly after the development of K-feldspar overgrowth and immediately preceding secondary grain dissolution. This is suggested by the fact that dolomite cement often appears in thin section to envelope quartz and feldspar overgrowth, yet dolomite cement is almost never found within secondary dissolution pores. This phase of cementation reduces visible porosity to very low levels within some beds.

Visible porosity in thin section samples of the Mt. Simon ranges from 0.5 - 23.0%. In general, dolomite cemented sandstones display visible porosity of less than 8%, whereas clean, well sorted fine to medium-grained sandstones display much higher visible porosity (10%). In these cleaner sandstones, intergranular pores are evenly distributed, and secondary pores (moldic and intragranular pores) are present in high proportions. Measured permeability values typically exceed 50 md in such sandstones. Some sandstone beds within the Mt. Simon (especially the lower one-third of the interval) contain discontinuous clay-rich laminations. Although such sandstones contain moderate visible porosity (5-12%) the distribution of pores is often uneven. Measured permeability is often less than 5 md.

Although the Mt. Simon is variable in terms of texture and cement distribution, clean, well sorted sandstones with moderately high permeability characterize most of the Mt Simon sandstone.

10.2.2.2 Radioactive Tracer Profiles

In Section 10.2.2 of this document it was noted that the upper 30 feet of the Mt. Simon contains porosity and permeability which are above average for the formation. It appears that this upper portion of the formation accepts the bulk of the injected fluid.

Radioactive tracer profile surveys, utilizing Iodine 131 as a source, were previously run in each of the active disposal wells. Interpretation of the surveys has indicated that from 68 percent to over 90 percent of the injected fluid enters the Mt. Simon within the upper 30 feet of the formation.

10.2.3 Formation Fracture Gradient

The "strength" of a rock is a term used in experimental structural geology that is only meaningful when the environmental conditions the rock is subjected to are specified. In general, the strength of a rock is its ability to withstand differential stress to the point at which it undergoes brittle failure. The environmental factors affecting a rock's strength include, but are not limited to, mineralogy, grain size, porosity, confining pressure, pore fluid pressure, temperature, presence of reacting solutions and duration of stress. The combined influence of these factors control the point at which a rock will undergo brittle failure. Certain rock types may behave differently under differing sets of environmental conditions. The strength of a rock can be measured under varied environmental conditions via laboratory methods.

When hydraulically fracturing a well, an array of physical events are interacting within the well/formation system. The fluid is moving down the wellbore with momentum influenced by pump horsepower, rate, fluid density, fluid viscosity, wellbore mechanics, and pipe friction. The resultant hydraulic force impacts the formation with applied stress of sufficient magnitude to cause the rock to fracture. A fracture occurs in the formation when hydraulic pressure overcomes the combined resistances of the tensile strength of the formation and the compressional stress caused by the overburden stress gradient.

The surface pressure observed at the moment the pumping operations are suddenly discontinued is called the instantaneous shut-in pressure, ISIP. This represents the minimum pressure required to open a hydraulically created fracture. The ISIP may be related to an equivalent bottomhole pressure, the bottomhole treating pressure, by using the following equation:

BHTP = ISIP + Ph where

BHTP	=	Bottomhole Treating Pressure (psi)
ISIP	=	Instantaneous Shut-in Pressure (psi)
Ph	=	Hydrostatic Pressure (psi).

Once the Bottomhole Treating Pressure is known, then the fracture gradient can be determined from the following equation:

Fracture Gradient = BHTP / Depth.

A proposed fracture stimulation was attempted on the Vickery Well No. 5 on October 13, 1982. The fracture stimulation ended when the well "screened out"; that is, the wellhead pressure during the treatment reached the maximum allowable pressure (determined from the strength of the tubulars in the well) before the wellbore could be flushed of the sand ladened fluid. With the wellbore filled with sand ladened fluid, an instantaneous shut-in pressure representative of the minimum pressure required to open the fracture cannot be obtained because the fracture has already closed. Therefore it follows that under these conditions the fracture gradient cannot be obtained.

The fact that a representative ISIP cannot be obtained is substantiated by the field data on Well No. 5. The data shows that the field service operator did not record ISIP in any of three places where ISIP is normally recorded on the field record. The events that occurred can be determined from the field strip chart and will be discussed chronologically. The fracing procedure was progressing normally until 10:42 AM with Dowell pumping sand laden fluid with 7 lb/gal sand at a rate of 15 bpm at 1900 psi. Then at 10:44 AM the sand was increased from 7 lb/gal to 9 lb/gal. Immediately, pressure started building and by 10:48 AM pressure was at 3300 psi. This indicated screen out and fracture closure. The pumps were shut down for a minute while pressure fell to 1125 psi and then to 650 psi. A brief attempt to flush out the sand by pumping the pumps resulted in another 3300 psi pressure peak at 10:48 AM which again indicated screen out and fracture closure. Dowell then ceased operations and rigged down. All test data was submitted to the OEPA in the Well 5 Completion Report.

In January, 1984, Well No. 4 was notched from 2904 to 2896 ft using a Hydrajet tool. After the notches were made a radioactive tracer was released at 1900 ft (inside the 5 inch casing) and pumped down the well. The radioactive tracer log indicated that most of the fluid was entering the notched portion of the wellbore. Next a pump test was performed to establish the breakdown pressure and fracture gradient. The pump test never clearly indicated a breakdown pressure; therefore, Halliburton's engineers felt the test was inconclusive as to whether or not a fracture had been initiated. A final instantaneous shut-in pressure of 970 psi was recorded during the pump test. The BHTP can be determined from the instantaneous shut-in pressure as follows:

$$BHTP = ISIP + Ph$$

In this case Ph is equal to the hydrostatic pressure of a 2819 ft column (depth below ground to casing seat) of 10 lb/gal brine (type of fluid in the wellbore when shut-in), which is 1464.5 psi. Therefore, the BHTP = 970 + 1464.5 = 2432.5 psi which is equivalent to a fracture gradient of 0.86 psi/ft (2434.5 psi/2819 ft).

Following the pump test it was decided to Hydrajet the entire open-hole interval and not to fracture stimulate the well. All test data was submitted to the OEPA in the Well 4 Completion Report.

In June, 1984, Well No. 2 was notched from 2930 to 2920 ft using a Hydrajet tool. Next a pump test was performed to establish the breakdown pressure and fracture gradient. The pump test never clearly indicated a breakdown pressure; therefore, Halliburton's engineers felt the test was inconclusive as to whether or not a fracture had been initiated. Instantaneous shut-in pressures of 730 to 740 psi were recorded during the pump test. Based on these pressures, a 10 lb/gal displacement fluid, and a casing depth of 2791 ft., BHTPs of 2180 psi and 2190 psi can be calculated using the method described earlier. Those values give a frac gradient of 0.781 and 0.785 psi/ft. Following the pump test Well No. 2 was fracture stimulated. At the end of the fracture treatment an ISIP of 830 psi was recorded. Previously it was thought that the displacement fluid was 2% potassium chloride. However, upon closer examination of the well records it was determined that the 2% potassium chloride solution was followed by a 10 lb/gal sodium chloride brine prior to shutting down the pumps. The hydrostatic head of the 10 lb/gal brine is calculated as follows:

Ph = 1.2 spec. gravity x 0.433 psi/ft x 2791 ft. = 1450 psi.

Using observed ISIP of 830 psi and Ph of 1450 psi yields:

BHTP = ISIP + Ph = 830 + 1450 = 2280 psi

which is a 0.82 psi/ft fracture gradient. All test data was submitted to the OEPA in the Well 2 Completion Report.

In August 1984, Well No. 6 was notched from 2890 to 2880 ft using a Hydrajet tool. Next a pump test was performed to establish the breakdown pressure and fracture gradient. The pump test indicated the breakdown pressure was approximately 1600 psi. An instantaneous shut-in pressure of 990 psi was recorded at the end of the pump test. Based on this pressure, a 9.9 lb/gal displace-ment fluid, and a casing depth of 2809 ft, BHTP of 2345 psi and a frac gradient of 0.83 can be calculated.

During the same test, the initial breakdown pressure was calculated to be 3069 psi at 2880 ft or 1.07 psi/ft using the 1600 psi surface pressure recorded. All test data was submitted to OEPA, April 4, 1985 in the Well No. 6 Completion Report.

In August, 1994, Vickery performed additional evaluations on the formation fracture gradients. A report dated August 4, 1994 was submitted to Ohio EPA entitled "Fracture Gradient Project." This report concludes that data demonstrates that the current maximum surface injection pressure of 785 psig *(at that time)*, which is based on a fracture gradient of 0.75 psi/ft, will not initiate new fractures or propagate existing fractures in the injection zone.

10.2.3.1 Uncertainty in Determination of Fracture Gradients

Uncertainty in the determination of fracture gradients can come from two sources ISIP, and Ph, as determined by the following equation:

$$BHTP = ISIP + Ph$$

This discussion will quantify the expected uncertainty in the determination of BHTP and therefore fracture gradients.

Hydrostatic head, Ph is calculated by the equation:

$$Ph = \text{Spec. Gravity} \times 0.433 \text{ psi/ft} \times \text{Depth.}$$

Field service supervisors generally agree that field procedures are well established to prevent significant errors in fluid density. Most agree that it is rare for fluid density to vary by more than 0.2 lb/gal from specified density. To get some idea of the magnitude of uncertainty that might occur from the maximum 0.2 lb/gal error, the parameters of Well No. 2 will be used. A 10 lb/gal brine, a fluid head of 2791 ft, and an ISIP = 830 psi, results in a fluid head of 1450 psi. These parameters resulted in a BHTP of 2280 psi

TABLE 10-2

MEASURED BOTTOMHOLE PRESSURES (BHP) AND TEMPERATURES (BHT)

DATE	WELL	DEPTH ft	MEASURED BHP1 psi	BHT °F	WELLBORE FLUID GRADIENT2 psi/ft	TOP OF MT. SIMON DEPTH ft	TOP OF MT. SIMON BHP psi	FORMATION FLUID GRADIENT3 psi/ft	MT. SIMON DATUM (-2192 subsea) DEPTH ft	MT. SIMON DATUM (-2192 subsea) BHP psi
25-Aug-87	1A	2735	1314.3	71.5	0.433	2808	1346	0.466	2808	1346
12-Sep-87	2	2750	1293.6	66.5	0.433	2803	1317	0.466	2808	1319
15-Jul-87	3	2841	1312	64.5	0.433	2800	1294	0.466	2810	1299
25-Aug-87	4	2735	1269.9	70.1	0.433	2812	1303	0.466	2810	1302
11-Sep-87	5	2735	1315.6	74.2	0.433	2791	1340	0.466	2810	1348
16-Aug-87	6	2735	1312.04	70.0	0.433	2796	1338	0.466	2807	1344

1Wells were shut in 36 hours prior to measurements but pressure was continuing to decline.

2Wells were filled with fresh water.

3Formation in the interwell area is saturated with waste stream (1.074 s.g.).

and a frac gradient of 0.82 psi/ft. If a maximum error occurred and 10.2 lb/gal brine was pumped into the wellbore under the same conditions, the new fluid head would be:

Ph = 1.224 Spec. Gravity x 0.433 psi/ft x 2791 ft = 1479 psi.

The bottom hole treating pressure would calculate as follows:

BHTP = ISIP + Ph = 830 + 1479 = 2309 psi.

The resultant frac gradient would be 0.83 psi/ft. The uncertainty of the frac gradient varying from 0.82 psi/ft to 0.83 psi/ft is insignificant.

Table 10-1A gives the pressure at the top of Mt. Simon in each well at the facility using the established 0.75 psi/ft maximum gradient.

10.2.4 Bottomhole Temperature and Pressure

An original bottomhole temperature was not recorded during the drilling and completion of any of the Vickery wells.

A temperature of 75.30F at 2500 ft was measured on September 19, 1983 in Well No. 6. This temperature gives a gradient of 1.00F/100 ft using an average surface temperature of 50.50F.

An original bottomhole pressure was measured during a drill stem test in Well No. 1 on March 16, 1972 before injection of waste was initiated. A pressure of 1132 psi was recorded at 2745 ft after swabbing the hole. This pressure gives a pressure gradient of 0.412 psi/ft.

Using a pressure gradient of 0.412 psi/ft gives a pressure of 1157 psi at 2808 ft, the top of the Mt. Simon in the #1-A disposal well. This pressure is assumed to be the original BHP at that depth. Table 10-2 shows the bottomhole temperature and pressure corresponding to depth for all the Vickery wells.

10.2.5 Chemical Characteristics of Formation Fluid

Formation water samples were obtained from two wells, Well No. 1 and Well No. 4 before injection was initiated (1972 and 1976, respectively). The analyses are presented in Table 10-3. The formation fluid is a sodium chloride solution with calcium/

TABLE 10-1A

CALCULATED MAXIMUM FORMATION PRESSURE

Well Number	Depth from Ground Level (Feet)	Pressure (psi)
1A	2798	2031
2	2794	2096
3	2789	2092
4	2803	2102
5	2782	2087
6	2786	2090

Maximum pressures are calculated based on a pressure gradient of 0.75 psi/foot of well depth, and the depth to the top of the Mt. Simon.

TABLE 10-3

FORMATION WATER ANALYSES

	Well No. 1 (Mt. Simon) by Halliburton 5-5-72	Well No. 1 (Mt. Simon) by Dowell 4-10-72	Well No. 4 (Mt. Simon) by CWM Laboratory August, 1976
Specific Gravity	1.095 at 75 °F	1.1 at 60 °F	--
Viscosity, cp	1.38 at 80 °F	--	--
pH, pH units	6.4	6.0	--
Total Dissolved Solids, mg/l	126,000	126,315	--
Chlorides, mg/l	78,000	78,000	83,000
Sulfate, mg/l	817	760	--
Calcium, mg/l	11,900	11,750	--
Magnesium, mg/l	2,250	2,250	--
Sodium, mg/l	33,100	33,500	--
Iron, mg/l	0	--	--
Barium, mg/l	--	--	--
Strontium, mg/l	--	--	--
Bicarbonate, mg/l	49	55	--
Sample Method	DST	DST	Air Lift until Cl-Stabilize
Sample Depth, Ft	2757 to 2927	2757 to 2927	--

NOTES:

mg/l = milligrams per liter cp = centipoise

°F = degrees Fahrenheit DST = drillstem test

-- denotes no information available

magnesium sulfate. The Mt. Simon sample from Well No. 4 was analyzed for chlorides only, and the chloride value from this well better represents the formation fluid since the well was backflowed until the chloride value of the formation water stabilized. The other samples may have been slightly diluted with drilling fluid or mud filtrate.

10.2.6 Waste Water Compatibility

Compatibility testing with formation water was done by Halliburton in conjunction with completion of Well No. 1. The testing for Well No. 1 demonstrated that mixing of the injected waste water with connate water resulted in precipitation of calcium sulfate. For this reason, a fresh water buffer fluid was injected into each newly constructed well to displace connate water away from the wellbore and ahead of the waste fluid front. For Well No. 1 core, the Halliburton tests were conducted with connate water, waste effluent, and a 1:1 mixture of connate water:waste. Very minor differences in permeability were encountered.

The permeability of the Precambrian basement to brine or waste was not tested. Permeability to air in a sample from 2926.7 feet in Disposal Well No. 1 was less than .0005 md (the limit of the test equipment) and porosity was .6 percent. The lithology of the basement in the No. 1 well was petrographically described as an alkali feldspar granite.

Testing by ERCO Petroleum Services, Inc. was done on a Mt. Simon core plug from Well No. 5 (from 2,850 ft.). Two acid wastes were injected with little change in the base permeability. However, some fines were generated as a result of acid reaction with the dolomitic portion of the matrix

In core testing, fines are free to exit the core, usually resulting in increased permeability due to acidization. Downhole, fines are not free to migrate out of the test media; therefore, formation of calcium sulfate and small fines could actually decrease permeability and serve to channel flow into areas of silica cementation. Permeability could also increase if the increased flow area due to acid reaction exceeds the flow area plugged due to precipitates and fines.

Core flow testing was done by ERCO Petroleum Services, Inc. to determine core compatibility of various blends. Core material from Well Nos. 2, 4, and 5 was evaluated, In each case permeability reductions occurred due to formation of mobile fines generated from acid reaction with the core matrix.

Vickery has conducted both core analysis and core compatibility testing in conjunction with the Waste Analysis Plan for evaluating future wastes.

Testing has shown that the Mt. Simon contains sufficient clay to exhibit sensitivity to fresh water but with proper pretreatment or blending, the Vickery waste stream is safely injected.

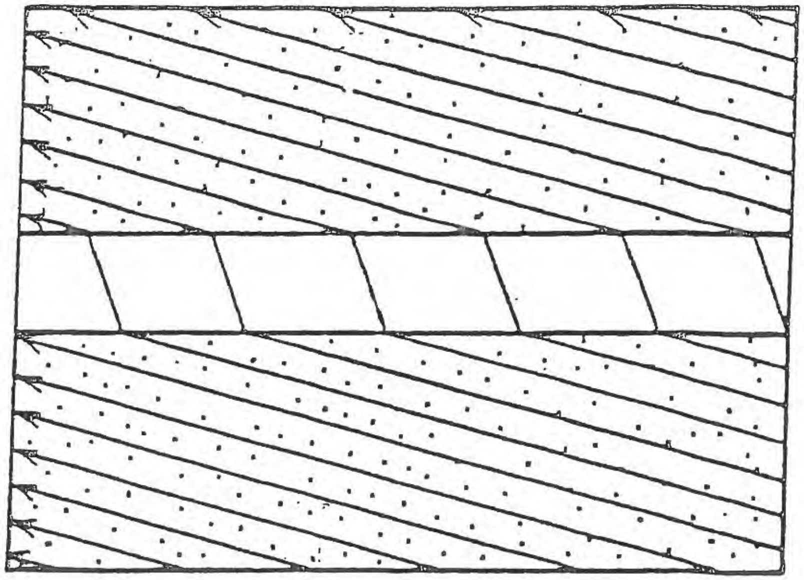
10.3 Containment Interval

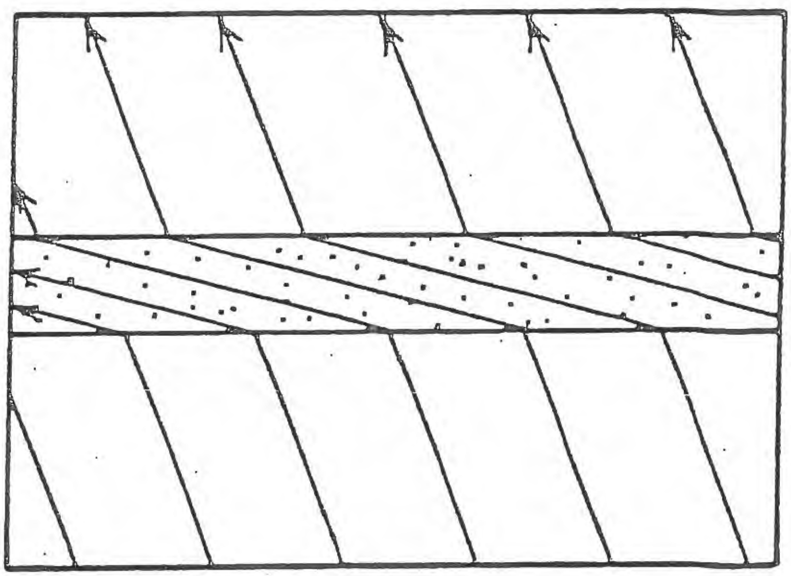
10.3.1 Lithology, Thickness

The containment interval is composed of alternating sequences of carbonates and clastics of the Rome, Conasauga, Kerbel and Knox Formations. The lithology of these formations was discussed in detail in Attachment D of this document.

The thickness of the containment interval is approximately 440 feet and includes zones which will arrest fluid movement as well as several "bleed off" zones. A "bleed off" zone is a stratigraphic interval containing greater hydraulic conductivity (related to permeability) than the intervals above and below it. When groundwater flowlines cross a boundary between formations with different hydraulic conductivities they are refracted. In a system composed of heterogenous layers and subject to a hydraulic gradient oriented perpendicular to the layering, fluid will move in a direction basically perpendicular to the layering in low conductivity units and basically parallel to the layering in high conductivity units on either side of the interface. Figure 10-11 demonstrates this concept. Fluid flow is dispersed laterally in a bleed off zone, and pressure gradient is significantly reduced in the down gradient layers. A more complete treatment of this phenomena can be found in Freeze and Cherry (1979), Chapter 5.1.

In 1993 a monitor well was installed at the interface of the Knox and Kerbel formations that is capable of monitoring formation fluid chemistry periodically and formation pressures continuously. This well is currently samples on an annual basis to evaluate





HYDRAULIC CONDUCTIVITY $\dfrac{K_1}{K_2} = 10$

FIGURE 10-11

REFRACTION OF FLOWLINES IN LAYERED SYSTEMS water quality and an annual report that also includes formation pressure data is prepared each year.

There has been no excess buildup in formation pressure from injection activity and water chemistry has remained stable.

The Rome Formation directly overlies the Mt. Simon injection interval. The Middle Rome dolomitic sandstone will act as a significant bleed off zone to reduce upward acting injection zone pressures.

10.3.2 Porosity and Permeability

10.3.2.1 Testing History

Porosity and permeability testing has been carried out on the Vickery cores in multiple stages, utilizing equipment of different sensitivity. Within the containment interval, stratigraphic zones of low permeability are of particular interest, and the capability of the core testing procedure to detect and measure low permeabilities is critical.

Waste Disposal Wells Nos. 4 and 5 were the most extensively cored within the containment interval. Initial testing of these cores, in 1976 and 1980 respectively, was recorded to a minimum permeability to air of only .1 md and minimum porosity of 3 percent. The cores were sampled every foot in these analyses, creating an extensive, nearly continuous data record, but not truly adequate for evaluating low permeability zones.

In the fall of 1987 Vickery had additional porosity and permeability testing performed on selected containment interval zones from Disposal Wells Nos. 2, 4 and 5, with No. 4 and 5 being the most extensively tested. The selected core plugs were tested for permeability to air to .01 md, and permeability to 100,000 ppm NaCl brine to a minimum of .0001 md.

In the Fall of 1989, a relatively minor amount of porosity and permeability testing was carried out in conjunction with significant petrographic work performed on the cores from Disposal Wells Nos. 1, 2, 4 and 5. This work involved testing permeability to air to a minimum of .0001 md, and porosity to a minimum of .1 percent. Additionally, three Lower Rome Dolomite (Shady) samples, one Conasauga and one Knox sample were tested for vertical permeability to 100,000 ppm NaCl brine to a minimum of .000001 md.

In 1992 testing was completed on an extensive round of flow through studies using Vickery core materials and synthetic waste. Also, significant additional petrography work was performed before and after the flow through tests. The complete report of this testing consisted of nine volumes, and was submitted to the USEPA and ODNR. The testing confirmed the conservative nature of the input data for the reservoir modeling.

10.3.2.2 Data Analysis

The varying sensitivities of the testing described in the preceding section makes analysis of low permeability zones within the containment interval rather difficult since a large amount of the rock materials sampled have permeabilities less than the value that could be measured at the time of testing. In an attempt to overcome this problem, average porosity and permeability for various formations, or formation segments, will be grouped according to the sensitivity of the data utilized, i.e. permeability values measured to .1 md, .01 md and .0001 md.

Since the equipment utilized in all the various analyses was capable of recording maximum porosity and permeability values encountered but not the minimum values, all the following "average" data should be regarded as conservative since the recorded average porosity and permeability are less than the true population average.

All porosities are averaged arithmetically. All vertical permeabilities are averaged using the harmonic mean. There is some uncertainty regarding the best measurement statistic for the "average" horizontal permeability, the choice being either the arithmetic mean or the geometric mean. The geometric mean is often markedly lower than the arithmetic mean for a sampled population.

Richardson, et.al. (1987) states that,

"It is usually observed that arithmetic averages of foot-by-foot horizontal permeabilities measured parallel to the bedding planes in the cores agree with permeabilities calculated from well tests. This is logical because ... arithmetic averaging assumes that flow occurs through the various strata parallel to the bedding planes. In this conceptual model, a consistent assumption is that vertical permeabilities measured perpendicular to the bedding planes should be averaged harmonically (in series) to reflect flow in the vertical direction..."

Fetter (1988), referring to hydraulic conductivity values obtain from tests of several monitoring wells areally distributed in the same aquifer, states that,

"An arithmetic mean of such a sample population tends to give more weight to the more permeable values. Some hydrogeologists believe that a more representative description of the average hydraulic conductivity of a hydrologic unit is the geometric mean. This is determined by taking the natural log of each value, finding the mean of the natural logs and then obtaining the exponential (ex) of that value to arrive at the geometric mean."

Vickery believes that arithmetic means are the more appropriate measurement for representing horizontal permeability in layered systems when utilizing the type of data available at the Vickery site. Both arithmetic and geometric values are presented in several tables in this document for comparative purposes.

Table 10-4 summarizes the porosity and permeability to air data, Table 10-5 summarizes permeability to 100,000 ppm NaCl brine. Table 10-5A provides details of the brine permeability testing. Table 10-5 demonstrates the difference in arithmetic verses geometric means for horizontal permeability.

The values of porosity and permeability used to define the various layers of the reservoir model are conservative when compared to the measured values indicated in Tables 10-4 and 10-5. Figure 10-12 shows the porosity and permeability values used in the model.

Figure 10-13 shows porosity and permeability data from Disposal Well No. 4 and the subdivision of the Rome Formation. Figure 10-14 shows the subdivisions of the Conasauga Formation with data obtained from the No. 5 well.

10.3.2.3 Porosity Development and Diagenesis

From the extensive petrographic study carried out by Vickery on the cores of Disposal Wells Nos. 2, 4 and 5 the following generalizations can be made about containment interval porosity development, and diagenesis.

TABLE 10-4

POROSITY AND PERMEABILITY TO AIR

Formation		Testing Period		
		pre 1980	1987	1989
BLACK RIVER (Actually in Confining Zone, data from ODNR No.1 M. and B. Asphalt, Seneca Co., OH)	N	0	0	17
	K_h (md)			.0012
	ϕ_h (%)			1.96
	N	0	0	17
	K_v (md)			.00054
	ϕ_v (%)			NA
KNOX	N	39	2	0
	K_h (md)	17.06	62.65	
	ϕ_h (%)	6.92	13.85	
	N	0	2	8
	K_v (md)		.22	.0002
	ϕ_v (%)		10.6	7.25
KERBEL	N	149	7	0
	K_h (md)	26.28	63.68	
	ϕ_h (%)	11.92	11.57	
	N	0	7	11
	K_v (md)		.22	.0011
	ϕ_v (%)		11.65	10.72
CONASAUGA	N	177	7	0
	k_h (md)	50.14	85.05	
	ϕ_h (%)	12.05	14.36	
	N	0	7	27
	K_v (md)		.076	.00037
	ϕ_v (%)		13.63	11.21
UPPER ROME DOLOMITE	N	34	3	0
	K_h (md)	1.189	.593	
	ϕ_h (%)	4.32	6.5	
	N	0	3	2
	K_v (md)		.024	.00018
	ϕ_v (%)		4.43	4.15

MIDDLE ROME DOLOMITIC SAND	N	30	3	0
	K_h(md)	9.50	157.0	
	ϕ_h (%)	10.27	16.5	
	N	0	3	7
	K_v(md)		.075	.00023
	ϕ_v(%)		14.07	9.01
LOWER ROME DOLOMITE (SHADY)	N	28	1	0
	K_h(md)	.574	.02	
	ϕ_h (%)	4.29	2.3	
	N	0	1	14
	K_v(md)		.01	.00013
	ϕ_v(%)		4.8	3.61

N = # of Samples
K_v= Harmonic mean
K_h= Arithmetic mean
ϕ_h= Arithmetic mean

TABLE 10-5A

SUMMARY OF POROSITY AND LIQUID PERMEABILITY TESTING
(Permeability Tests Used 100,000 ppm NaCl as the Saturant Fluid)

Formation*	Depth (ft)	Well #	Test Date** (Year)	Kh (md)	Kv (md)	Øh (%)	Øv (%)
Knox	2387.3	5	1989		.000024		2.4
Knox	2390.0	5	1984		.0034		6.3
Knox	2394.4	5	1987	.56		8.4	
Knox	2394-95	5	1987		.01		8.1
Knox	2402.0	5	1987	12.0		19.3	
Knox	2402-03	5	1987		6.7		13.1
Kerbel	2442.0	4	1987	114.0		14.9	
Kerbel	2442-43	4	1987		12.0		14.3
Kerbel	2448.3	4	1987	.06		6.7	
Kerbel	2448-49	4	1987		.01		6.2
Kerbel	2454.2	4	1987	.29		9.2	
Kerbel	2454-55	4	1987		.25		9.6
Kerbel	2492.3	4	1987	65.0		21.6	
Kerbel	2492-93	4	1987		4.3		21.0
Kerbel	2436.1	5	1987	.39		9.8	
Kerbel	2436-37	5	1987		.22		9.0
Kerbel	2438.4	5	1987	.08		8.4	
Kerbel	2438-39	5	1987		.04		8.8
Kerbel	2440.0	5	1984	.75		10.9	
Kerbel	2445.1	5	1987	1.4		10.4	
Kerbel	2445-46	5	1987		1.1		12.6
Kerbel	2477.0	5	1984	8.1		26.8	
Conasauga	2497.1	2	1987	35.0		11.3	
Conasauga	2497-98	2	1987		.17		10.8
Conasauga	2569.9	2	1987	.02		12.5	
Conasauga	2569-70	2	1987		.01		12.7
Conasauga	2509.9	4	1989		.000588		4.7
Conasauga	2518.2	4	1987	.001		5.4	
Conasauga	2518-19	4	1987		.0007		6.4
Conasauga	2546.9	4	1987	43.0		19.9	
Conasauga	2546-47	4	1987		.06		15.3
Conasauga	2564.5	4	1987	49.0		18.6	
Conasauga	2564-65	4	1987		13.0		15.4
Conasauga	2507.0	5	1984		.0034		6.3

TABLE 10-5A

SUMMARY OF POROSITY AND LIQUID PERMEABILITY TESTING
(Permeability Tests Used 100,000 ppm NaCl as the Saturant Fluid)

Formation*	Depth (ft)	Well #	Test Date** (Year)	Kh (md)	Kv (md)	Øh (%)	Øv (%)
Conasauga	2519.6	5	1987	133.0		24.2	
Conasauga	2519-20	5	1987		1.8		23.7
Conasauga	2525.0	5	1984	32.1		22.8	
Conasauga	2538.0	5	1984	27.0		14.6	
Conasauga	2571.3	5	1987	.01		8.6	
Conasauga	2571-72	5	1987		.0003		11.1
Upper Rome	2585.4	5	1987	.08		7.5	
Upper Rome	2585-86	5	1987		.01		4.1
Upper Rome	2590.6	5	1987	.0008		3.9	
Upper Rome	2590-91	5	1987		.01		3.0
Upper Rome	2594.8	5	1987	.001		8.1	
Upper Rome	2594-95	5	1987		.001		6.2
Middle Rome	2704.3	4	1987	.01		7.7	
Middle Rome	2704-05	4	1987		.005		7.0
Middle Rome	2727.2	4	1987	5.6		16.7	
Middle Rome	2727-28	4	1987		.03		14.2
Middle Rome	2730.2	4	1987	311.0		25.1	
Middle Rome	2730-31	4	1987		11.0		21.0
Lower Rome	2800.0	4	1989		.000022		0.2
Lower Rome	2807.5	4	1989		.000092		1.4
Lower Rome	2786.6	5	1987	.0001		2:3	
Lower Rome	2786-87	5	1987		.0006		4.8
Lower Rome	2790.5	5	1989		.000036		3.9

* Formation boundaries utilized here are tied to the determinations made during the 1989 petrographic study performed on the CWM Vickery cores. Please refer to Table 9-1 and Appendix P.

**1984 and 1987 data is in Appendix I. 1989 data is in Appendix P.

Kh = Liquid permeability in a horizontal plug.
Kv = Liquid permeability in a vertical plug.
Øh = Porosity in a horizontal plug.
Øv = Porosity in a vertical plug.

TABLE 10-5

PERMEABILITY TO 100,000 PPM NaCl BRINE

Formation*	N	Kh_a(md)	Kh_g(md)	N	Kv(md)
Knox	2	6.28	2.59	3	.0000951
Kerbel	9	20.23	1.48	7	.0519
Conasauga	9	35.46	2.285	8	.00131
Upper Rome Dolo.	3	.027	.0040	3	.0025
Mid Rome Sand	3	105.5	2.592	3	.0129
Lower Rome Dolo.	1	.0001	.0001	4	.0000466

N = # of Samples
Kv= Harmonic mean
Kh_a = Arithmetic mean
Kh_g = Geometric mean

* Determination of which formation particular sample depths represent is based on the 1989 petrographic study, see Table 9-1. See Table 11-5A for details of samples utilized in this table.

FIGURE 10-12

Hydraulic properties used for analysis of vertical pressurization and waste migration.

Model Layer	Unit	Horizontal Permeability (md)	Vertical Permeability (md)	Porosity
1	Black River	0.10	0.01	0.05
2	Black River	0.10	0.01	0.05
3	Black River	0.10	0.01	0.05
4	Wells Creek	0.014	0.0014	0.05
5	Knox	5	0.5	0.05
6	Knox	5	0.5	0.05
7	Knox	5	0.5	0.05
8	Kerbel	20	2	0.10
9	Kerbel	20	2	0.10
10	Conasauga Silty Sand	20	20	0.15
11	Conasauga Shale	0.014	0.0014	0.06
12	Conasauga Shale	0.014	0.0014	0.06
13	Conasauga Silty Sand	35	35	0.15
14	Conasauga Silty Sand	35	35	0.15
15	Conasauga Silty Sand	35	35	0.15
16	Conasauga Silty Sand	35	35	0.15
17	Rome Dolomite	0.05	0.005	0.03
18	Rome Dolomite	0.05	0.005	0.03
19	Rome Dolomite	0.05	0.005	0.03
20	Rome Dolomite	0.05	0.005	0.03
21	Rome Dolomite	0.05	0.005	0.03
22	Rome Silty Sand	5	5	0.10
23	Rome Silty Sand	5	5	0.10
24	Rome Dolomite	0.006	0.0006	0.03
25	Rome Dolomite	0.006	0.0006	0.03
26	Rome Dolomite	0.006	0.0006	0.03
27	Rome Dolomite	0.006	0.0006	0.03
28	Rome Dolomite	0.006	0.0006	0.03
29	Rome Dolomite	0.006	0.0006	0.03
30	Rome Dolomite	0.006	0.0006	0.03
31	Mt. Simon Sandstone	42	42	0.15
32	Mt. Simon Sandstone	42	42	0.15
33	Mt. Simon Sandstone	42	42	0.15

DISPOSAL WELL NO.4
ROME FORMATION

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS		POROSITY PERCENT	
		HORIZONTAL	VERTICAL		
177	2694.3	<0.10		3.0	
178	2695.5	<0.10		<3.0	
179	2696.5	<0.10		4.4	
180	2697.5	<0.10		<3.0	
181	2698.5	<0.10		3.8	
182	2699.5	0.12		4.9	UPPER DOLOMITE
183	2700.5	<0.10		5.8	
184	2701.5	<0.10		6.5	
185	2702.5	<0.10		6.8	
186	2703.5	<0.10		5.3	
187	2704.5	<0.10		7.1	
188	2705.5	<0.10		<3.0	
189	2706.5	<0.10		9.3	
190	2707.5	1.2		9.6	
191	2708.5	1.7		10.3	
192	2709.5	2.0		10.2	
193	2710.5	1.6		11.0	
194	2711.5	8.6		9.8	
195	2712.5	1.4		13.0	
196	2713.5	5.4		15.1	
197	2714.5	1.0		15.4	
198	2715.5	3.6		13.9	
199	2716.5	0.21		10.0	
200	2717.5	30.		19.8	
201	2718.5	44.		21.3	
202	2719.5	0.17		9.5	
203	2720.5	1.2		10.5	
204	2721.5	<0.10		9.7	
205	2722.5	1.2		9.8	MIDDLE DOLOMITIC SANDSTO.
206	2723.5	0.13		5.6	
207	2724.5	0.85		10.6	
208	2725.5	5.2		12.2	
209	2726.5	10.		15.5	
210	2727.5	163.		24.3	
211	2728.5	0.30		9.4	
212	2729.5	0.63		11.0	
213	2730.5	<0.10		3.0	
214	2731.5	0.20		6.4	
215	2732.5	<0.10		<3.0	
216	2733.5	<0.10		<3.0	
217	2734.5	<0.10		<3.0	
218	2735.5	0.62		8.8	
219	2736.5	<0.10		3.7	
220	2797.5	<0.10		<3.0	
221	2798.5	<0.10		<3.0	
222	2799.5	0.27		4.9	
223	2800.5	<0.10		<3.0	
224	2801.5	<0.10		<3.0	
225	2802.5	<0.10		6.3	
226	2803.5	<0.10		4.0	
227	2804.5	5.4		8.3	
228	2805.5	<0.10		<3.0	
229	2806.5	<0.10		<3.0	LOWER DOLOMITE (SHADY)
230	2807.5	<0.10		<3.0	
231	2808.5	<0.10		<3.0	
232	2809.5	<0.10		<3.0	
233	2810.5	<0.10		<3.0	
234	2811.5	<0.10		<3.0	
235	2812.5	<0.10		<3.0	

MAJOR HORIZONTAL

POROSITY AND PERMEABILITY DIVISIONS

FIGURE 10-13

DISPOSAL WELL NO.5

CONASAUGA FORMATION

SMP. NO.	DEPTH	PERM. TO AIR MD. MAXIMUM	90 DEG.	VERT.	POROSITY GEX. FLD.	
105	2490.0-91.0	17.0	15.0		11.7	
106	2491.0-92.0	5.3	4.6		11.4	
107	2492.0-93.0	4.2	3.8		9.1	SILTY SANDSTONE
108	2493.0-94.0	5.6	3.8		8.0	
109	2494.0-95.0	79.0	63.0		5.1	
110	2495.0-96.0	*	2.9		6.7	
111	2496.0-97.0	*	3.5		7.3	
112	2497.0-98.0	4.0	3.7		11.0	
113	2498.0-99.0	<0.1	<0.1		5.3	
114	2499.0-00.0	<0.1	<0.1		3.8	
115	2500.0-01.0	<0.1	<0.1		4.2	
116	2501.0-02.0	<0.1	<0.1		5.3	
117	2502.0-03.0	*	<0.1		5.1	
118	2503.0-04.0	<0.1	<0.1		4.6	
119	2504.0-05.0	<0.1	<0.1		4.2	
120	2505.0-06.0	*	<0.1		4.0	
121	2506.0-07.0	<0.1	<0.1		3.8	
122	2507.0-08.0	<0.1	<0.1		3.6	SILTY SHALE
123	2508.0-09.0	<0.1	<0.1		5.1	
124	2509.0-10.0	<0.1	<0.1		7.6	
125	2510.0-11.0	<0.1	<0.1		9.0	
126	2511.0-12.0	<0.1	<0.1		8.4	
127	2512.0-13.0	<0.1	<0.1		7.2	
128	2513.0-14.0	<0.1	<0.1		14.3	
129	2514.0-15.0	<0.1	<0.1		6.5	
130	2515.0-16.0	0.7	0.6		9.5	
131	2516.0-17.0	1.3	0.6		10.8	
132	2517.0-18.0	27.0	25.0		12.6	
133	2518.0-19.0	141.0	132.0		19.4	
134	2519.0-20.0	431.0	399.0		22.3	
135	2520.0-21.0	37.0	36.0		15.5	
136	2521.0-22.0	29.0	23.0		13.1	
137	2522.0-23.0	72.0	68.0		21.0	
138	2523.0-24.0	53.0	48.0		18.6	
139	2524.0-25.0	118.0	110.0		20.8	
140	2525.0-26.0	108.0	98.0		22.3	
141	2526.0-27.0	58.0	58.0		13.1	
142	2527.0-28.0	18.0	15.0		12.7	
143	2528.0-29.0	45.0	43.0		17.1	
144	2529.0-30.0	6.4	5.6		9.5	
145	2530.0-31.0	1.9	0.8		9.6	
146	2531.0-32.0	22.0	18.0		12.2	
147	2532.0-33.0	36.0	29.0		11.1	
148	2533.0-34.0	54.0	45.0		14.1	
149	2534.0-35.0	408.0	243.0		14.2	
150	2535.0-36.0	57.0	54.0		14.2	
151	2536.0-37.0	69.0	67.0		13.3	
152	2537.0-38.0	78.0	75.0		13.1	
153	2538.0-39.0	60.0	59.0		13.8	
154	2539.0-40.0	60.0	57.0		14.1	
155	2540.0-41.0	90.0	85.0		14.2	
156	2541.0-42.0	68.0	67.0		15.4	
157	2542.0-43.0	62.0	59.0		15.4	
158	2543.0-44.0	83.0	79.0		19.2	
159	2544.0-45.0	126.0	114.0		19.9	
160	2545.0-46.0	62.0	56.0		17.7	
161	2546.0-47.0	52.0	51.0		20.0	SILTY SANDSTONE
162	2547.0-48.0	45.0	42.0		13.1	
163	2548.0-49.0	45.0	43.0		12.7	
164	2549.0-50.0	73.0	70.0		16.3	
165	2550.0-51.0	54.0	54.0		17.9	
166	2551.0-52.0	29.0	28.0		19.3	
167	2552.0-53.0	*	20.0		10.3	
168	2553.0-54.0	40.0	39.0		14.9	
169	2554.0-55.0	64.0	61.0		12.5	
170	2555.0-56.0	5.1	4.6		15.9	
171	2556.0-57.0	*	94.0		19.2	
172	2557.0-58.0	*	85.0		14.6	
173	2558.0-59.0	11.0	10.0		15.4	
174	2559.0-60.0	57.0	41.0		16.6	
175	2560.0-61.0	40.0	34.0		20.8	
176	2561.0-62.0	36.0	34.0		21.3	
177	2562.0-63.0	24.0	23.0		16.3	
178	2563.0-64.0	11.0	10.0		8.7	
179	2564.0-65.0	9.6	7.9		9.7	
180	2565.0-66.0	2.2	1.1		13.6	
181	2566.0-67.0	0.3	0.2		11.3	
182	2567.0-68.0	3.6	3.2		12.0	
183	2568.0-69.0	2.0	1.4		15.4	
184	2569.0-70.0	1.9	1.9		10.8	
185	2570.0-71.0	1.8	1.7		9.3	
186	2571.0-72.0	<0.1	<0.1		5.7	
187	2572.0-73.0	0.1	0.1		6.7	
188	2573.0-74.0	<0.1	<0.1		7.8	
189	2574.0-75.0	1.2	1.1		9.5	
190	2575.0-76.0	0.4	0.4		6.9	
191	2576.0-77.0	0.3	0.2		5.6	
192	2577.0-78.0	0.8	0.4		8.6	
193	2578.0-79.0	<0.1	<0.1		5.4	

FIGURE 10-14

MAJOR HORIZONTAL

POROSITY AND PERMEABILITY DIVISIONS

10.3.2.3.1 Rome Formation

The Rome Formation can be divided into three units. The lowermost unit is a sandy grainstone dolomite. The middle section is a dolomitic fine to very fine grained sandstone. The upper unit is a sandy grainstone dolomite similar to the lowermost unit.

Although very few samples were examined in detail from the Middle Rome, diagenetic events affecting porosity development in the Middle Rome include initial quartz overgrowth development and K-feldspar development which is often followed by extensive precipitation by pore-filling finely crystalline dolomite. Dolomitization was followed by dissolution of unstable framework grains leading to the formation of moldic and intragranular pores. In many cases, dolomite cement appears to have occluded intergranular pores, and therefore the predominant pore types are intragranular and moldic. These pores appear to be very poorly interconnected and permeability values are typically below 1 md.

Dolomitized grainstones of the uppermost and lowermost Rome contain very low levels of visible porosity and contain high amounts of pore filling dolomite cement. Rare visible pores are generally isolated and consist largely of moldic and vuggy dissolution pores. A small number of fractures occur in both the lower and upper Rome. Blue-light fluorescent microscopy and standard thin section petrography show that the majority of fractures are laterally discontinuous and appear occluded laterally by dolomite cement, and less commonly by calcite cement. Some fractures are laterally continuous and display especially sharp breaks, free of mineralization throughout the length of the fracture. These fractures appear to have been induced, perhaps during the coring process. Permeability to air values in the upper and lower Rome are generally below 1 md and in many cases, below 0.0001 md. Vertical permeability to 100,000 ppm NaCl brine measured in the lower Rome averaged 0.000047 md from 4 samples.

10.3.2.3.2 Conasauga Formation

The Conasauga is variable lithologically, consisting of finely interlaminated siltstones, very fine-grained sandstones and dolomites in the upper portion of the formation, and dolomite cemented fine to very fine-grained sandstone in the lower Conasauga.

In the upper portion of the Conasauga, visible porosity is negligible within dolomite and clay-rich siltstone laminations. Visible porosity can also be very low along relatively clean carbonate cemented very fine grained sandstone laminations. Some fine grained sandstone laminations display well developed visible porosity. Burial diagenetic influences in these sandstones include early formation of poorly developed grain-coating chlorite, which was succeeded by quartz overgrowth cementation, which was followed in turn by K-feldspar overgrowth cementation, detrital framework grain dissolution, and pore-bridging illite precipitation. Dolomite cement appears to post-date illite formation, occurring in coarse rhombic pore-filling and occasionally grain replacing crystals. Visible porosity can be as high as 23% within thin sandstone beds in the upper Conasauga. In such beds, intergranular and secondary dissolution pores are present in nearly equal proportions and often appear well interconnected laterally. However, such beds are thin and are often bounded vertically by relatively tight beds (i..e. dolomites, dolomitic siltstones).

With the exception of the lowermost 15 feet of the lower Conasauga (which is tightly cemented by pervasive dolomite cement), the lower Conasauga consists of fairly clean thick-bedded sandstone which often displays high amounts of visible porosity in thin section. These sandstones display similar diagenetic relationships to those of clean sandstones in the upper Conasauga. Visible porosity commonly exceeds 15%, with abundant intergranular and secondary pores. Measured permeability values in this interval commonly exceed 50 md.

10.3.2.3.3 Kerbel Formation

The Kerbel consists largely of relatively clean, very fine to fine grained sandstones that contain variable amounts of dolomite cement. Visible porosity in the Kerbel ranges from 4.0-20% with pore-filling dolomite cement acting as the controlling factor in porosity distribution. Dolomite cement is both grain replacing and pore-filling (most common mode of occurrence) and often displays a very even distribution of medium subhedral crystals. Dolomite cement appears to have post-dated quartz and feldspar overgrowth cementation and predates the development of secondary grain-moldic and intragranular pores. Dolomite cement is present in almost every sandstone examined in the Kerbel and occurs most commonly within intergranular pores. Where dolomite cement exceeds 30%, visible porosity rarely exceeds 10%. Dolomite cement not only effects permeability by reducing overall porosity, it appears to also effect permeability by reducing overall pore size and occluding interconnection between pores.

Sandstones with high amounts of porosity occur in both the upper and lower Kerbel, in which measured whole core permeability typically ranges from 10-50 md. However, sandstones containing high amounts of dolomite cement are common with permeability values often less than 5 md.

10.3.2.3.4 Knox Formation

The Knox samples from Well No. 4 and Well No. 5 consist of dolomite and mixed dolomite/sandstone. Visible porosity is especially low within relatively pure dolomite grainstones, where the dominant form of porosity is isolated moldic and vuggy dissolution pores. Intergranular and moldic dissolution porosity can be well developed along sandstone beds. Moldic pores are sometimes well developed in sandy dolomite beds, but appear poorly interconnected. Intergranular and secondary pores within dolomitic sandstone laminations often appear locally well interconnected, however, such laminations are commonly laterally and vertically discontinuous. Fractures are present in the Knox, but like those of the Rome Formation, most are laterally discontinuous due to dolomite cementation. There are also fractures that display especially clean breaks with no evidence whatsoever of mineralization - these are believed to have been induced during coring.

In 1993 a monitor well was installed at the interface of the Knox and Kerbel formations that is capable of monitoring formation fluid chemistry periodically and formation pressures continuously. This well is currently samples on an annual basis to evaluate water quality and an annual report that also incluses formation pressure data is prepared each year.

There has been no excess buildup in formation pressure from injection activity and water chemistry has remained stable.

10.3.3 Formation Fracture Gradient

Very little information exists on the regional fracture gradient for formations of the containment interval. According to oilfield service companies contacted the fracture gradient for the formations in the containment interval is .80 psi/ft. This is based on their experience with the Knox formation in Morrow, Holmes and Coshocton Counties. This fracture gradient is .05 psi/ft higher than the 0.75 psi/ft fracture gradient used to establish the maximum wellhead injection pressure at the Vickery site.

10.3.4 Chemical Characteristics of Formation Fluid

A water sample from the Kerbel Formation was obtained from Vickery Well No. 4 before injection was initiated in 1976. The formation fluid at this interval is similar to the Mt. Simon Formation fluid except for a lower chloride content and higher calcium and sulfate content. Formation water analysis results for the Kerbel are included in Table 10-6.

10.3.5 Waste Water Compatibility

Most of the formations in the containment interval have dolomite ($CaMg(CO_3)_2$) as a significant mineralogical constituent The general equation for the reaction of dolomite with acid is:

$$CaMg(CO_3)_2 + 4H^+ = Ca^{++} + MG^{++} + 2CO_2 + 2H_2O$$

This chemical reaction results in the neutralization of the acidic waste through the dissolution of dolomite.

URM (1984) states that the dissolution of dolomite and the resultant release of Ca^{++} in solution may result in the formation of gypsum ($CaSO_4 \bullet nH_2O$) upon reaction with sulfate in the wastestream, which may precipitate in intergranular or fracture pore spaces. This mineral precipitation would cause a reduction in permeability within the naturally low permeability formations of the containment interval.

Testing of Well No. 1 Mt. Simon sandstone (containing a minor dolomite component) demonstrated that mixing of connate water and injected acidic waste water resulted in the precipitation of calcium sulfate

Results of other studies (International Symposium on Subsurface Injection of Liquid Wastes, 1986), indicate the possibility that the permeability reduction of dolomite samples seen after the samples were flowed with synthetic brine (to obtain repeatable results) then with pickling liquor (acid) was caused by precipitation of iron carbonate.

TABLE 10-6

FORMATION WATER ANALYSES

OF

THE KERBEL

Well No. 4
(Kerbel)
by CWM Laboratory
8-5-76

Specific Gravity	1.067
Viscosity, cp	--
pH, pH units	--
Total Dissolved Solids, mg/l	--
Chlorides, mg/l	62,037
Sulfate, mg/l	1,143
Calcium, mg/l	7,900
Magnesium, mg/l	--
Sodium, mg/l	--
Iron, mg/l	2.18
Barium, mg/l	--
Strontium, mg/l	--
Bicarbonate, mg/l	--
Sample Method	DST
Sample Depth, ft	--

NOTES:

mg/l = milligrams per liter   cp = centipoise

^{o}F = degrees Fahrenheit   DST = drillstem test

-- denotes no information available

Attachment B

II. Seismic Discussion

5.3 SEISMICITY

The relationship of injection activities to seismic events is an area of concern for regulatory agencies. Vickery can demonstrate that injection activity at the site cannot be related to any known seismic event.

At present, Vickery maintains injection pressures well below the calculated fracture gradient of the Mt. Simon Sandstone, calculated from the wells at the site, so that the threshold for failure will not be exceeded and trigger a seismic event.

Figure 5-27 is a map of the Ohio River Basin showing the degree of seismic risk for the area. Most of Ohio has been determined to be in an area of minor to moderate risk. Figure 5-28 is a somewhat more sophisticated figure from the US Geological Survey showing a 10% probability of a seismic event exceeding a particular acceleration relative to gravity during a 50-year period. The figure indicates that there is a 10% chance of a seismic event occurring that exceeds only 2 to 3 percent of the force of gravity in northeastern Ohio, within 50 years. Figure 5-29 describes the possible damage associated with seismic events of certain magnitudes.

In 1977 a nine station seismic monitoring array became operational in western Ohio (Anna Network), and in 1981 was supplemented by four stations in Indiana. This Ohio-Indiana seismic network was operated by the University of Michigan under contract to the United States Nuclear Regulatory Commission. This contract was discontinued in 1992 according to ODNR. This network was capable of detecting seismic activity which may originate at the Vickery site with a magnitude of approximately 2.0 or greater. This magnitude is near the threshold for human feeling at the epicenter.

Currently, ODNR has a 29 station network of seismographs in Ohio called OhioSeis, The Ohio Seismic Network. The stations are located at colleges, universities, and other institutions throughout Ohio but are primarily concentrated in the most seismically active areas. The systems utilize a desktop computer, internet connection and a Global Position System receiver. The exact epicenter, magnitude and time frame of any seismic activity can be determined in a matter of minutes by checking data from any three or more of the seismograph units. Figure 5-30 identifies the approximate location of these 29 seismic monitoring stations.

Utilizing the data from the Anna Network and the OhioSeis Network, earthquake information depicting seismic events in Ohio since 1776 is shown in Figure 5-31. Figure 5-31A also present the information as in Figure 5-31, the difference is that Figure 5-31A was created using the Ohio Seis Networks Interactive Mapping Utility. A tabulation of these events is given in Table 5-1 and Table 5-2. The figures and tables reveal no seismic activity detected in the vicinity of the Vickery site. Seismic events recorded around Sandusky County are shown in Figure 5-32. Three historical and two recent seismic events are listed below:

> In February of 1975, an earthquake occurred in the south-central portion of Sandusky county about 12 miles south-southwest of the site. Three earthquakes were recorded in north-central Seneca County. Two of those earthquakes occurred in 1936 about 16 miles southwest of the site. The third earthquake occurred in 1961 about 20 miles southwest of the site. These earthquake occurred before injection activities began at the site. The two most recent earthquakes occurring closer to the site occurred in 2010 and were located near Gibsonburg (May, 2010) and Fostoria (February, 2010).

The Vickery facility completed an extensive seismic reflection investigation in late 1989. The results of the study are included in a document entitled "Seismic Reflection Investigation" dated February 1991 by Weston Geophysical Corporation. A copy of that report is included as

Attachment I. The conclusions drawn from that study are included in Attachment I, Section 4. There was no indication of vertical faulting or fracturing of the sedimentary units or the Precambrian surface within the area of the investigation.

The evaluation of the historical seismic record indicates that the Vickery facility is located in an area of relatively little seismic risk. There is no evidence that the injection activities at Vickery during the past four decades have caused any seismic events.

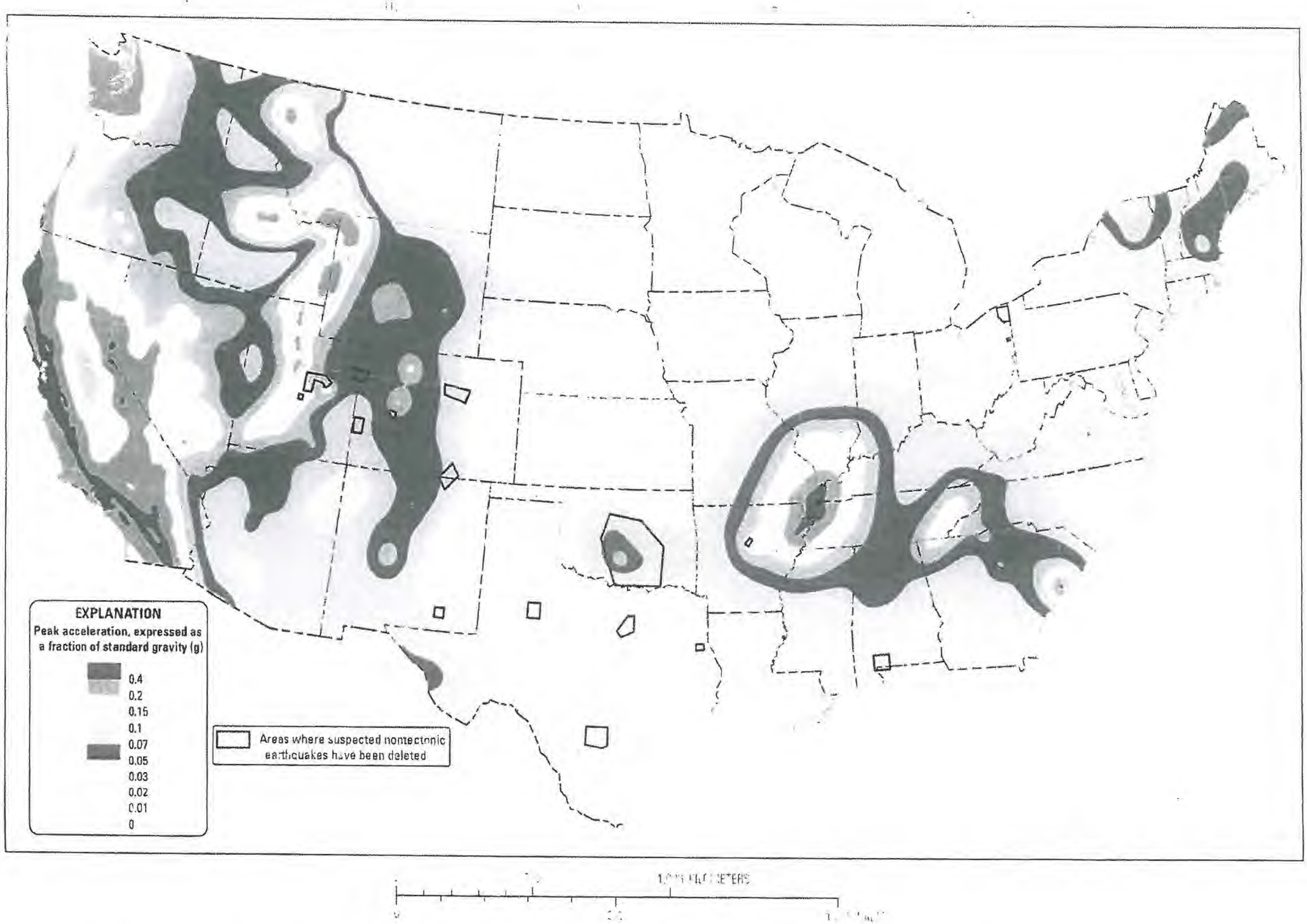


Figure 5-28 **Ten-percent probability of exceedance in 50 years map of peak ground acceleration**

Seismic Magnitude/Intensity Scales

Scale Magnitude	Mercalli	Description
	I	Detected only by sensitive instruments
0-2.9	II	Felt only by a few persons at rest, especially on upper floors of buildings; delicately suspended objects may swing
	III	Felt noticeably indoors, especially on upper floors of buildings, but not always recognized as earthquake; standing autos may rock slightly; vibrations like a passing truck
2.9-4.1	IV	During the day, felt indoors by many, outdoors by few; at night, some awakened; dishes, windows, doors disturbed; walls make creaking sound; sensation like heavy truck hitting building; standing autos rock noticeably
	V	Felt by most people; some breakage of dishes, windows, and plaster; unstable objects overturned; disturbance of trees, poles, and other tall objects
4.1-5.4	VI	Felt by all, many frightened and run outdoors; some heavy furniture may move; falling plaster and chimneys, damage slight
	VII	Everyone runs outdoors; damage to buildings varies depending on quality of construction; noticed by people driving autos
	VIII	Panel walls thrown out of frames; walls, monuments, chimneys fall; sand and mud ejected; drivers of autos disturbed
5.4-7.3	IX	Buildings shifted off foundations, frame structures thrown out of plumb; ground cracked; underground pipes broken
	X	Most masonry and frame structures destroyed*; ground badly cracked, rails bent, landslides; sand and mud shift; water splashes over river banks
7.3 +	XI	Few structures remain standing; bridges destroyed; broad fissures in ground, pipes broken, landslides, rails bent
	XII	Damage total; waves seen on ground surface, lines of sight and level distorted, objects thrown up into the air

- The Mercalli scale is a semi-quantitative linear scale.
- The Richter scale is quantitative logarithmic scale.
- *Buildings constructed with special anti-earthquake techniques, are able to withstand tremors of up to 8.5 on the Richter scale.

Severity	Scale Magnitude	Mercalli
Mild	0-2.9	I-III
Moderate	2.9-4.1	IV-V
Intermediate	4.1-5.4	VI-VII
Severe	5.4-7.3	VIII-X
Catastrophic	7.3 +	XI-XII

[Ohio Seismic Network]

Last update July 19, 2010

175 YEARS OF SERVICE 1837-2012

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Division of Geological Survey
2045 Morse Rd.,
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Columbus, OH
43229-6693

Phone:
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Fax:
(614) 447-1918

E-Mail
Location Map

Earthquake Contacts:
24 Hour Earthquake Reporting Hotline:
1-855-QuakeOH
1-855-(782-5364)

Figure 5-29

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Location Map

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1-855-(782-5364)

Media Inquiries
Quake Info Center:
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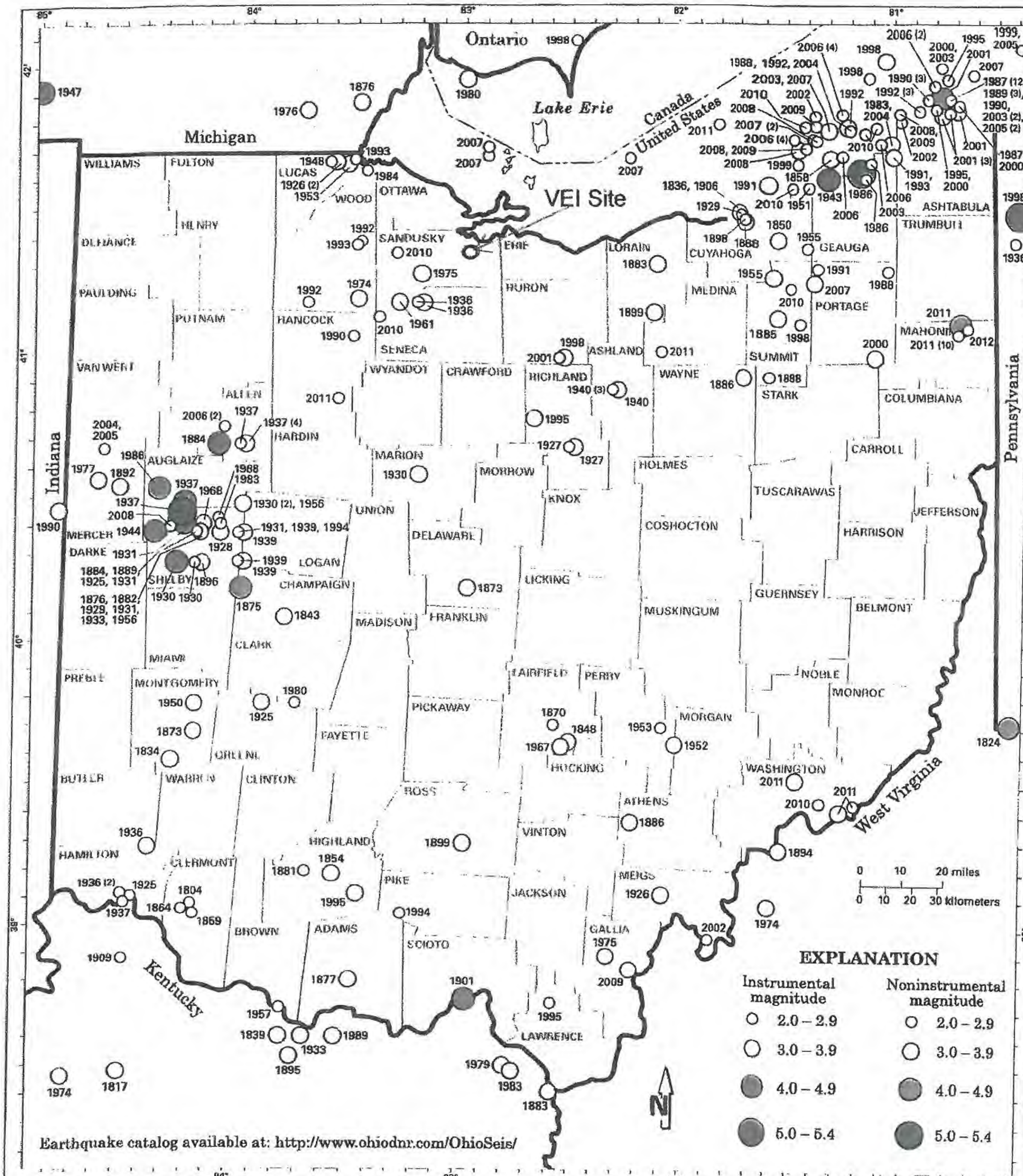
- HRC Laboratory

OhioSeis The Ohio Seismic Network

Figure 5-30

STATE OF OHIO • DEPARTMENT OF NATURAL RESOURCES • DIVISION OF GEOLOGICAL SURVEY

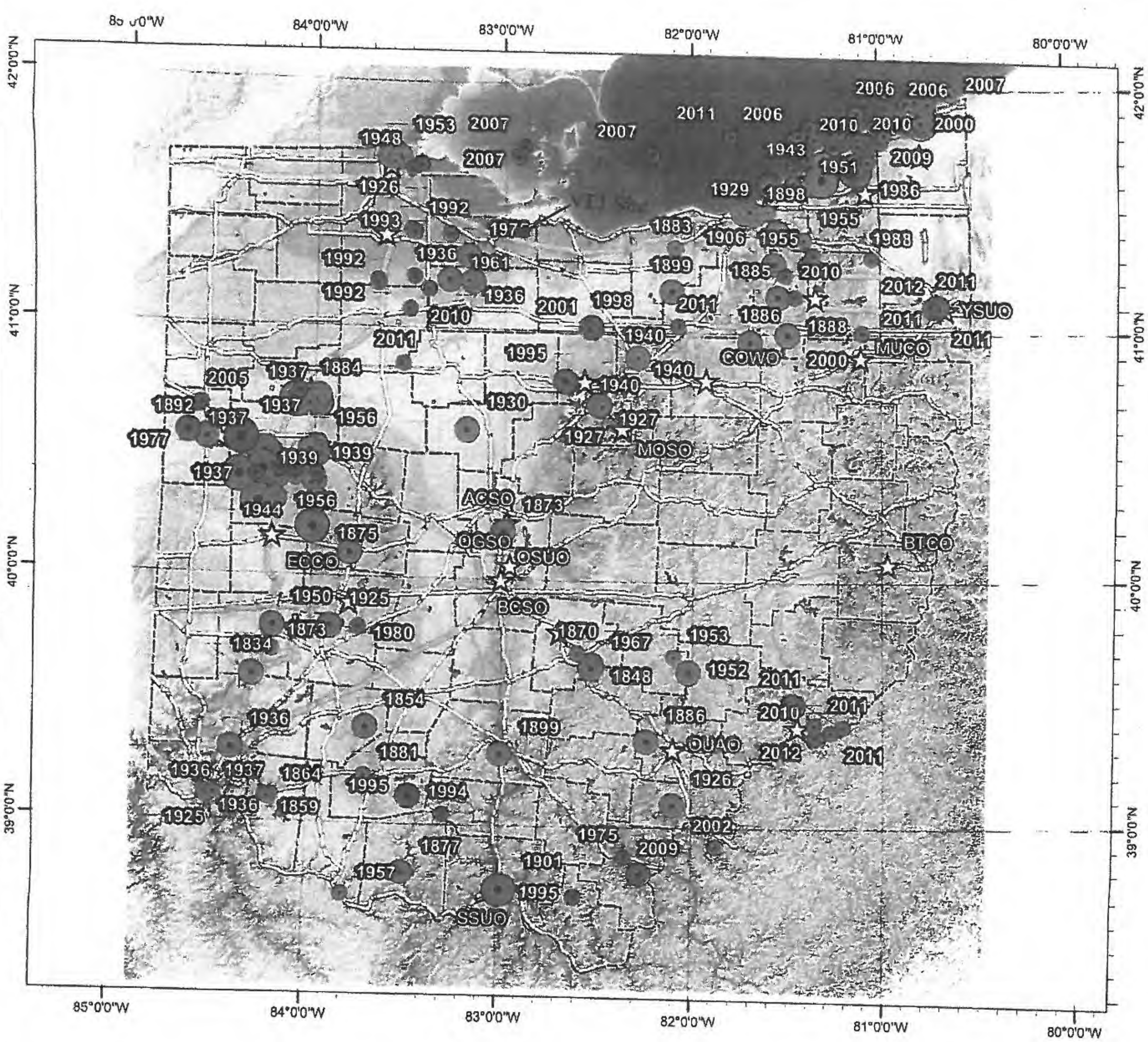
EARTHQUAKE EPICENTERS IN OHIO AND ADJACENT AREAS



OhioSeis
The Ohio Seismic Network

Recommended citation: Ohio Division of Geological Survey, 2012, Earthquake epicenters in Ohio and adjacent areas—color version: Ohio Department of Natural Resources, Division of Geological Survey Map EG-2, generalized page-size version, 1 p., scale 1:2,000,000.

Figure 5-31



EARTHQUAKE EPICENTERS IN OHIO

EXPLANATION

Instrumental Epicenters	Historical Epicenters
Magnitude, mbLg	Magnitude, Mercalli
2.0 - 3.0	2.0 - 3.0
3.0 - 4.0	3.0 - 4.0
4.0 - 5.0	4.0 - 5.0
5.0 and up	5.0 and up
	Seismic Stations

OhioSeis
The Ohio Seismic Network

0 50 100 150 200 Scale in Kilometers

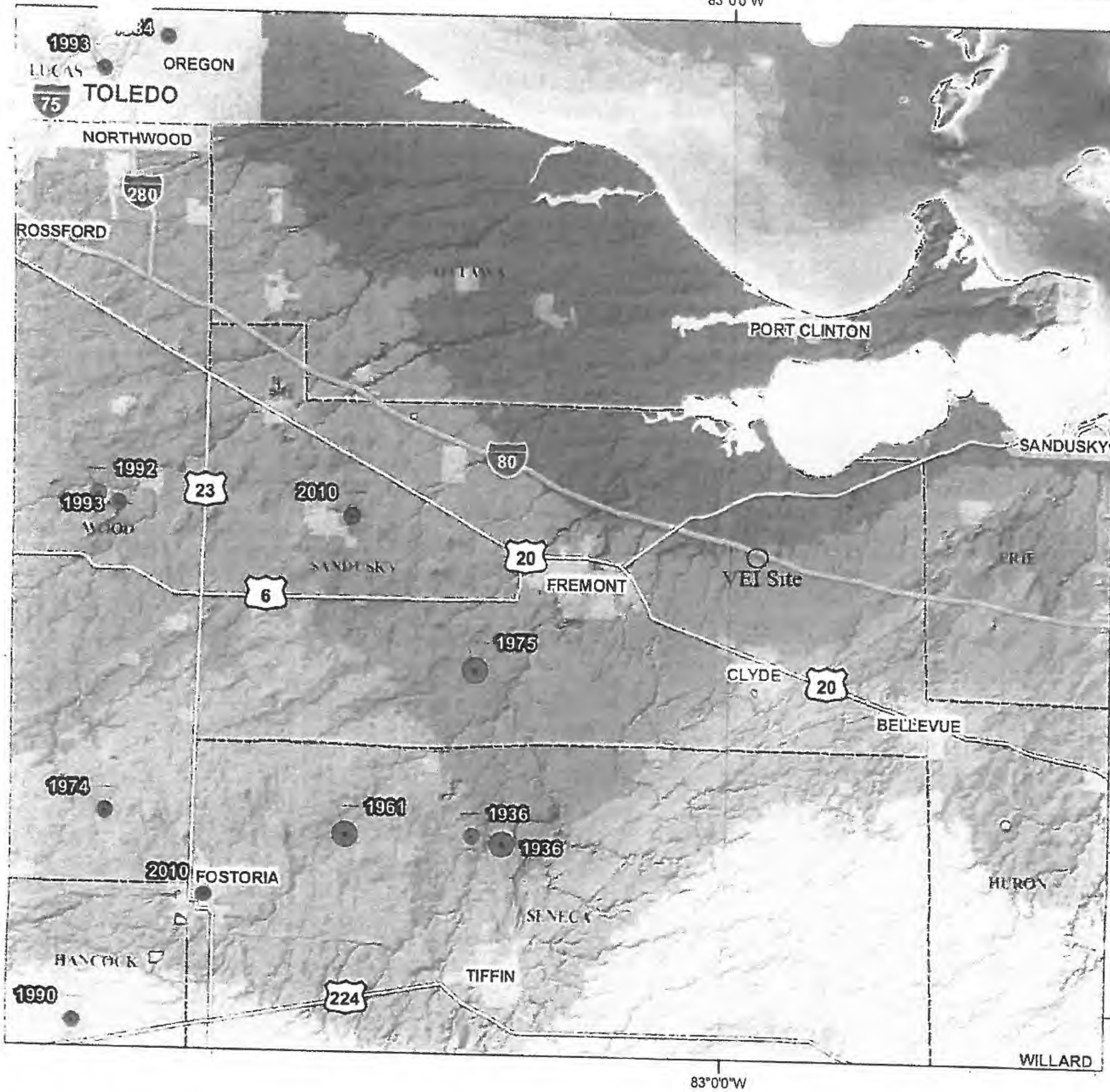
0 20 40 60 80 100 Scale in Miles

DISCLAIMER

Recommended bibliographic citation:
2002 (Revised 2008), Earthquake epicenters in Ohio and adjacent areas: Ohio Division of Geological Survey Map EG-2, Internet Mapping Service, http://www.dnr.state.oh.us/website/geosurvey/earthquakes/viewer.htm

-dp-

Figure 5-31A



EARTHQUAKE EPICENTERS IN OHIO

EXPLANATION

Instrumental Epicenters	Historical Epicenters
Magnitude, mbLg	Magnitude, Mercalli
2.0 - 3.0	2.0 - 3.0
3.0 - 4.0	3.0 - 4.0
4.0 - 5.0	4.0 - 5.0
5.0 and up	5.0 and up
	☆ Seismic Stations

ODNR Geological Survey

OhioSeis
The Ohio Seismic Network

0 8 16 24 32 Scale in Kilometers

0 3 6 9 12 15 Scale in Miles

-dp-

DISCLAIMER
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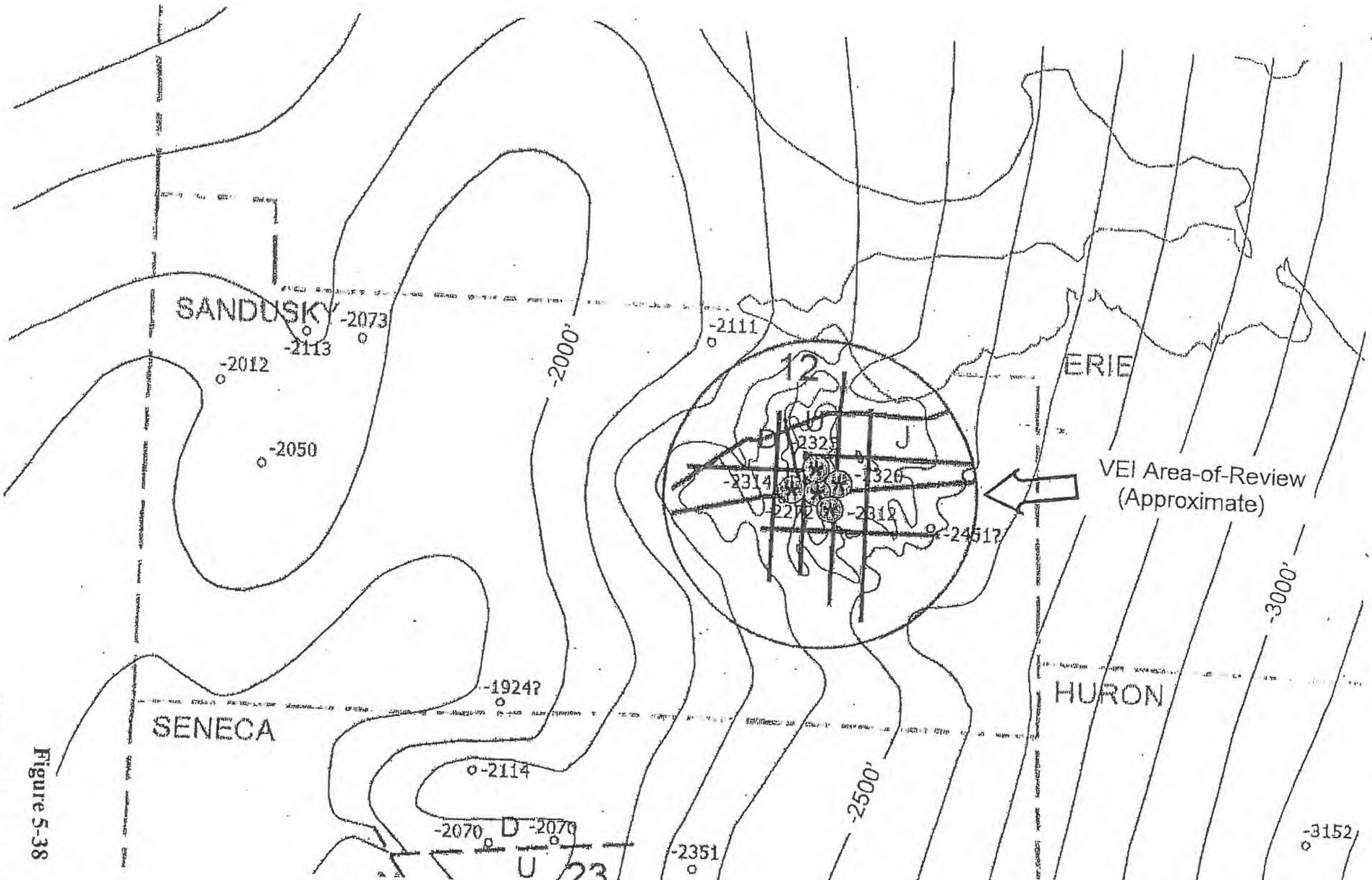
Recommended bibliographic citation:
2002 (Revised 2008), Earthquake epicenters in Ohio and adjacent areas: Ohio Division of Geological Survey Map EG-2, Internet Mapping Service, http://www.dnr.state.oh.us/website/geosurvey/earthquakes/viewer.htm

Figure 5-32



Precambrian Structure Map

(Contour labels added by Texas World)

Figure 5-38

From Baranoski, 2002

SEISMIC REFLECTION INVESTIGATION

for

CHEMICAL WASTE MANAGEMENT SITE

Vickery, Ohio

February 1991

Weston Geophysical
CORPORATION

EXECUTIVE SUMMARY

As agreed to with the State of Ohio Environmental Protection Agency (OEPA), a seismic reflection program was undertaken within a five mile radius of Chemical Waste Management's (CWM) Vickery well site in northwestern Ohio. The results of this program of studies, including responses to OEPA comments on a preliminary report, are reported herein.

Results of the agreed upon seismic reflection survey, which constitutes extensive coverage within a five mile radius of the CWM Vickery site, are presented in the form of seismic reflection time profiles (previously submitted) and time and depth structure, and time and depth isopach maps of the identified formations (Appendix A). The maps are drawn on the prominent reflection horizons evident in the stratigraphic section from the Precambrian (570 my) basement unconformity through the Middle Ordovician (458 my) Trenton Limestone. Sedimentary rock units within this section, comprising the injection interval (Mt. Simon), containment interval (Rome, Conasauga, Kerbel, Knox), and the lower portion of the confining interval (Wells Creek, Black River, Trenton), represent the most distinct reflection horizons on the seismic records. The integrity of these rock units is of primary importance in assessing the potential for vertical migration of injected wastes and potential for triggering earthquakes.

Overall, the 59 miles of seismic reflection data, obtained within a five mile radius of the CWM Vickery site, are consistent with the gently southeastward dipping Precambrian unconformable surface overlain by relatively uniform, Early Paleozoic sedimentary units. Superimposed on the regional southeastward dipping surface, a low-relief anticline trends north-south beneath the Vickery site. Time structure and isochron and depth converted structural contour and isopach maps of the Precambrian surface and the Mt. Simon, Rome, and Trenton units, indicate localized sediment thinning and thickening, predominantly within the Mt. Simon, due to nondeposition and/or erosion and filling over paleotopographic relief. Slight arching of the interpreted formations suggests minor intermittent uplift.

Based on analysis and interpretation of the seismic reflection data and the subsequent Line 7 segment produced by data processing using various enhancement techniques, and in the context of local and regional geological, geophysical and seismological information, the origin of the anticlinal feature beneath the CWM Vickery site is related to minor episodic crustal adjustments in the 300 million year interval from Late Precambrian (560mya) to Middle Paleozoic (280mya). The low-gradient relief (120 feet) and lack of evidence for significant brittle deformation, is consistent with a geological environment which fulfills the requirements for "no migration" of wastes through identifiable fractures or faults. Also evidence of the potential to trigger seismicity of any significance is absent.

Attachment C

I. Proposed Well Diagram

II. Proposed Casing and Cementing Programs

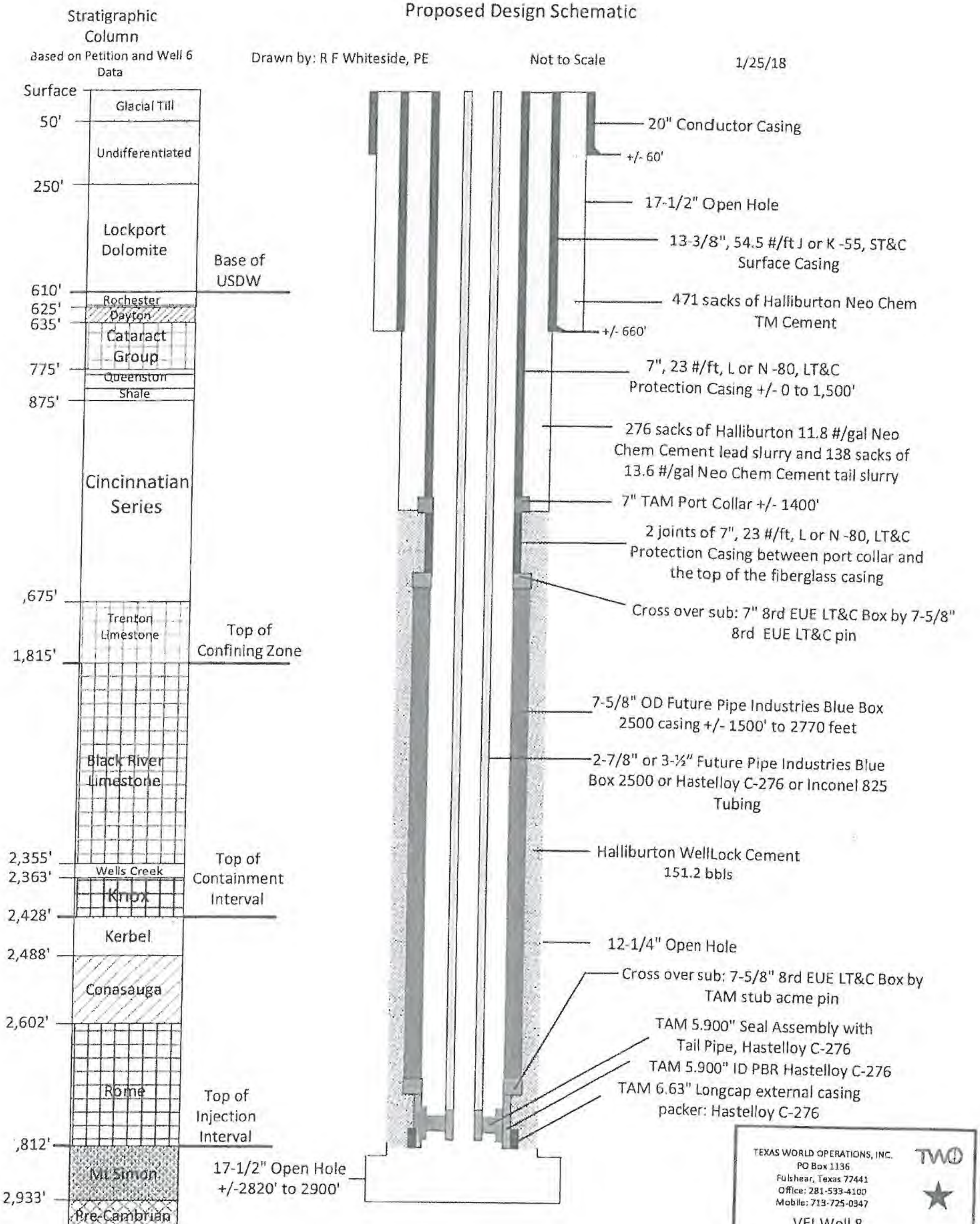
III. Proposed Well Completion

Attachment C

I. Proposed Well Diagram

Drilling Program: Figure 2

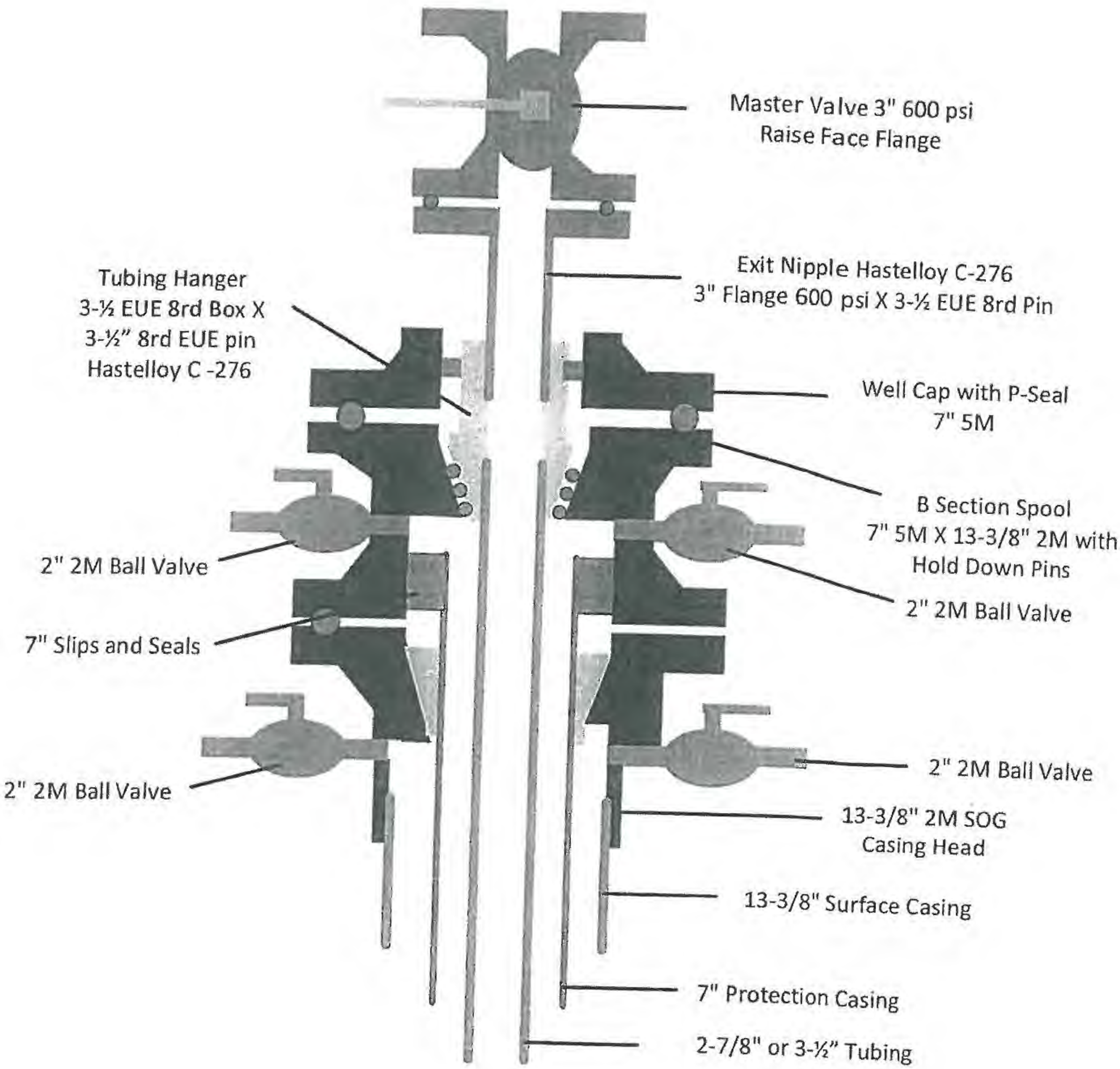
VEI Plant Well 8
Proposed Design Schematic



Drilling Program: Figure 3

VEI Typical Wellhead
Plant Well #7 & #8

Drawn By: R F Whiteside, PE   Not to Scale   1/25/18



TEXAS WORLD OPERATIONS, INC.
PO Box 1136
Fulshear, Texas 77441
Office: 281-533-4100
Mobile: 713-725-0347

Attachment C

II. Proposed Casing and Cementing Programs

Texas World Operations, Inc.
PO Box 1136
Fulshear. Texas 77441-1136

Drilling Program Plant Well #8

INTRODUCTION

The Vickery Plant Well #8 design incorporates external mechanical sealing between the formation and casing at the injection interval interface. The design addresses galvanic corrosion of the casing by isolating the dissimilar metals of construction by a long section of fiberglass casing. The large open hole size relative to the outside diameter of casing coupled with the centralizer design will ensure excellent cement emplacement by reducing the probability of channeling. All the casing materials of construction expected to have a useful life of more than 40 years.

INJECTION WELL CONSTRUCTION

1. Total depth of the proposed well is +/-2,900 feet.

2. Casing Program

   The casing and tubing selections are based on American Petroleum Institute (API Bulletins 5C2 and 5C3) standards, compatibility tests, historical materials performance, discussions with vendors, past performance records and materials brochures were also considered when selecting the materials to be used in construction of the proposed injection wells. Historical performance with similar injectate streams suggests these tubulars will be resistant to any corrosive effects due to contact with the injectate stream components. The casings to be used in the construction of the well are designed for the life expectancy of the well. The casings proposed for the injection well are rated to have sufficient structural strength for the design life of the well including the maximum pressures and tensile stress which may be experienced at any point along the length of casing or tubing.

   A. Materials and Specifications

Conductor Casing, planned depth = surface to +/- 60 feet

20-inch, 94.0 lb./ft, H-40, Welded end Casing Specifications	
Wall	0.438 inches
I.D.	19.124 inches
Drift	18.936 inches

Coupling O.D.	Not applicable
Collapse	520 psi
Burst	2,110 psi
Pipe Body Strength	1,480,000 lbs.
Joint Strength	Not applicable
Capacity	0.3538 bbls/ft

Surface Casing, planned depth = surface to +/- 660 feet

13-3/8-inch, 54.50 lb./ft, J-55, Buttress or STC Casing Specifications	
Wall	0.380 inches
I.D.	12.615 inches
Drift	12.459 inches
Coupling O.D.	14.375 inches
Collapse	1,130 psi
Burst	2,730 psi
Pipe Body Strength	853,000 lbs.
Joint Strength	1,038,000 Buttress 547,000 ST&C
Capacity	0.1545 bbls/ft

Protection Casing, planned depth = surface to +/- 1,500 feet

7-inch, 23 lb./ft, N-80, LTC Casing Specifications	
Wall	0.317 inches
I.D.	6.366 inches
Drift	6.241 inches
Coupling O.D.	7.656 inches
Collapse	3,270 psi
Burst	4,360 psi
Pipe Body Strength	366,000 lbs.
Joint Strength	313,000 lbs.
Capacity	0.0393 bbls/ft

Protection Casing, planned depth = surface to +/- 1,500 to 2770 feet

Future Pipe Industries 7-5/8-inch, Blue Box 2500-C, EUE 8rd Casing Specifications	
Wall	0.7075 inches
I.D.	6.21 inches
Drift	6.11 inches
Coupling O.D.	7.725 inches
Collapse	2,900 psi
Burst	2,000 psi
Axial Tensile Rating	83,500 lbs.
Tensile Strength, Hoop	31,300 psi
Joint Strength	83,500 lbs.
Capacity	0.0390 bbls/ft

Protection Casing, planned depth = surface to +/- 2,770 to 2800 feet

TAM International 6-5/8-inch, Schedule 80, Hastelloy C-276 PBR Specifications	
Wall	0.432 inches
I.D.	Honed to: 5.900 inches ID
Drift	5.900 inches
Coupling O.D.	7.725 inches
Collapse	10,950 psi
Burst	14,260 psi
Axial Tensile Rating	Exceeds 7" 23 lb./ft
Tensile Strength, Hoop	Exceeds 7" 23 lb./ft
Joint Strength	Exceeds 7" 23 lb./ft
Capacity	0.0390 bbls/ft

Injection Tubing, planned depth = surface to +/- 2,800 feet

2-7/8-inch, Hastelloy C-276 or Inconel-825 tubing Specifications Weakest Tubing Future Pipe Industries – 2-7/8 Blue Box 2500	
Wall	0.217 inches
I.D.	2.47 inches
Drift	2.47 inches
Coupling O.D.	4.06 inches
Collapse	2,900 psi
Burst	2,500 psi
Pipe Body Strength	30,000 lbs.
Joint Strength	22,500 lbs.
Capacity	0.00579 bbls/ft
Notes: VEI may elect to use 3-1/2" FRP, Hastelloy or Inconel as an alternative	

B. The casing strings specified in the permit application are designed for worst case or maximum possible load which could reasonably occur during the drilling, cementing, operation or testing of the well. The design process evaluated the collapse, internal yield (burst) and yield strength (tension) for each casing string. The design includes safety factors to adjust for any damage or wear during the drilling operations or workovers performed inside the casings.

All design parameters used are based on and referenced from the following two publications from the American Petroleum Institute (API).

1) API Bulletin 5C2, 21st edition, October 1999; Performance Properties of Casing, Tubing and Drill Pipe.
2) API Bulletin 5C3, 6th edition, November 1, 1994; Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties.

The most common range of design safety factors and assumed conditions, as defined by API, are given below.

Collapse: 1.0 to 1.125 based on API minimum collapse pressures. The string is assumed to be empty and with either mud, salt water or actual area pressure (formation pressure) applied to the annulus.

Internal Yield (burst): 1.0 to 1.33 based on API minimum yield values. A column at formation pressure is generally assumed to be exerted on all depths within the casing. Casing strings are often designed to withstand pressures equal to the estimated formation breakdown (fracture) pressure at the respective casing shoe, from blowout considerations and /or the pressures applied at the casing shoe by the maximum required casing pressure test.

Tension: 1.6 to 2.0 based on API minimum joint strength, with string freely hanging in air (no buoyancy).

The following minimum safety factors are required for each casing string in the proposed injection well.

Safety Factors	
Collapse:	1.125
Internal Yield (burst):	1.330
Tension:	2.000

The maximum collapse pressure will most likely occur during cementing or backflowing of the well. The maximum internal yield pressure (burst) will occur during internal pressure tests on each casing string to verify mechanical integrity. The maximum tension will occur while landing the casing string in the wellhead assembly.

The pressure gradient used in the burst and collapse calculations is the calculated cement gradient for the Mt. Simon (injection zone) which is the casing shoe point. The gradient is valid based on the API calculation specifications. The 0.706939 psi/ft gradient is equivalent to a column of 13.6 lbs./gal cement from 2800 feet to surface. This gradient is beyond normal conditions expected during the drilling, completion, testing and operation of the proposed injection wells.

Definitions and Formulas:

P_C: *minimum collapse pressure, psi*

P_I: *minimum burst pressure, psi*

L_J: *minimum joint strength, lbs*

D_C: *collapse, maximum setting depth, feet*

D_I: *burst, maximum setting depth, feet*

D_T: *tension, maximum setting depth, feet*

G:	*gradient, psi/ft*
S_F:	*safety factor*
w:	*pipe weight, lb/ft*
lb/ft:	*pounds per foot*
psi:	*pounds per square inch*

$D_C = (P_C / S_F) \div G$

$D_I = (P_I / S_F) \div G$

$D_T = (L_J / S_F) \div w$

Note: The values for P_C, P_I and L_J are from published API and Future Pipe Industries tables for specific casing size, steel grade and thread type. The numbers are calculated using formulas in the previously referenced API bulletins.

Calculations:

<u>13-3/8" surface casing, 54.5 lb./ft, J or K 55, STC thread connections</u>

Design setting depth = +/- 660 feet
P_C (collapse) = 1,130 psi
P_I (burst) = 2730 psi
L_J (tension) = 514,000 lbs.
G = 0.706939 psi/ft

$D_C = (P_C / S_F) \div G$	:	(1130 psi/1.125) ÷ 0.706939 psi/ft = 1,420.837 feet
$D_I = (P_I / S_F) \div G$	:	(2730 psi/1.330) ÷ 0.706939 psi/ft = 2,903.549 feet
$D_T = (L_J / S_F) \div w$	:	(514,000 lbs /2.000) ÷ 36 lb./ft = 4,715.896 feet

All calculated design depths are within the maximum calculated safety depths.

<u>7" protection casing, 23 lb./ft, L or N-80, LTC thread connections</u>

Design setting depth = +/- 1500 feet
P_C (collapse) = 3,830 psi
P_I (burst) = 6,340 psi
L_J (tension) = 442,000 lbs.
G = 0.706939 psi/ft

$D_C = (P_C / S_F) \div G$	:	(3,830 psi/1.125) ÷ 0.706939 psi/ft = 4,853.48 feet
$D_I = (P_I / S_F) \div G$	:	(6,340 psi/1.330) ÷ 0.706939 psi/ft = 11,327.49 feet
$D_T = (L_J / S_F) \div w$	:	(442,000 lbs /2.000) ÷ 23 lb./ft = 4,055.05 feet

All calculated design depths are within the maximum calculated safety depths.

7-5/8" Fiberglass protection casing, 12.6 lb./ft, Blue Box 2500, LTC thread connections

Design setting depth = +/- 1500 to +/- 2800 feet
Future Pipe has a 4:1 Safety Factor built into the performance numbers, therefore no additional safety factors are necessary.
P_C (collapse) = 2,500 psi
P_I (burst) = 2,500 psi
L_J (tension) = 30,000 lbs.
G = 0.706939 psi/ft

$D_C = (P_C / S_F) \div G$	:	(2,500 psi/1) ÷ 0.706939 psi/ft = 3,960.739 feet
$D_I = (P_I / S_F) \div G$	:	(2,500 psi/1) ÷ 0.706939 psi/ft = 3,960.739 feet
$D_T = (L_J / S_F) \div w$	:	(30,000 lbs. /1) ÷ 12.6 lb./ft = 2,380.952 feet

All calculated design depths are within the maximum calculated safety depths.

2-7/8" Fiberglass injection tubing, 2.0 lb/ft, Blue Box 2500, 8rd EUE thread connections

Design setting depth = +/- 2,800 feet
P_C (collapse) = 2,500 psi
P_I (burst) = 2,500 psi
L_J (tension) = 30,000 lbs.
G = 0.883493 psi/ft (gradient for 11.5 lb/gal fluid + 800 psi surface injection pressure)

$D_C = (P_C / S_F) \div G$	:	(2,500 psi/1) ÷ 0.4571 psi/ft = 3,169.237 feet
$D_I = (P_I / S_F) \div G$	:	(2,500 psi/1) ÷ 0.4571 psi/ft = 3,169.237 feet
$D_T = (L_J / S_F) \div w$	:	(30,000 lbs. /1) ÷ 2.0 lb/ft = 15,000 feet

All calculated design depths are within the maximum calculated safety depths.

C. Inspection requirements for carbon steel tubulars:

i. All tubulars must be manufactured to the current edition of API 5CT.
ii. All API threads must be manufactured to the current edition of API 5B.
iii. AMALOG IV or equivalent full-length electromagnetic inspection.

7. Centralizers, scratchers, etc

13-3/8" Surface Casing

Two centralizers on float joint. Bowspring centralizer on next 4 casing collars, then every 2nd joint except a centralizer will be on the top two collars. Total of 16 – 20 centralizers.

Protection Casing

Two centralizers on float joint. The fiberglass casing will have centralizers molded onto each joint. Bowspring used on the 7-inch steel casing. Bowspring centralizers will be run above and below the multiple-stage cementing and one every 2nd joint of casing, with two centralizers on the top joint. Total of 80 - 90 centralizers

8. Cementing

The regulations require that the cement be emplaced from the casing setting depth to surface for both the surface and protection casings. Adequate cement bond to the pipe and the formation must also be demonstrated by running a cement bond tool. In this program, certain cement vendor trade names are used. Final cement slurries will use equal and equivalent products based on final vendor recommendations.

Conductor: Cemented with Redi-mix to surface if drilled or augered.

Surface Casing: (+/- 660 feet to surface)

Spacer
6% Gel Spacer
20 lbs./bbl. National Premium Gold 30 bbl.

Lead Slurry		
NeoCem TM	Fluid Weight:	15.8 lbs./gal
5.36 Gal/sk Fresh Water	Slurry Yield:	1.236 ft3/sack
	Total Mixing Fluid:	5.36 gal/sk
	Calculated Volume:	103.7 bbl
	Proposed Volume:	103.7 bbl
	Top of Fluid:	0 ft
	Calculated Fill:	660 ft
	Calculated Sack:	470.88 sack
	Proposed Sack:	471 sack
	Excess:	30% over caliper volume

Note: Volumes above based on 30% excess over gauge hole volumes. Actual cement volumes will be based on open-hole caliper volume + 30% excess. More excess may be added based on hole conditions. Cement blends may be modified to suit actual well conditions.

Protection Casing: First Stage (+/- 2800 feet to +/- 1400 feet):

Note: Volumes above based on 10% excess over gauge hole volumes in drilled bore hole. Actual cement volumes will be based on open-hole caliper volume plus a minimum of 10% excess. Cement blends may be modified to suit

Stage 1
Spacer
6% Gel Spacer
20 lbs./bbl. National Premium Gold 30 bbl.

Lead Slurry		
SBM CMT WellLock PKG	Fluid Weight:	11.2 lbs./gal
	Calculated Volume:	151.2 bbl
	Top of Fluid:	1400 ft
	Calculated Fill:	1400 ft
	Excess:	10% over caliper volume

Protection Casing: Second Stage (+/- 1400 feet to +/- 0 feet):

Spacer
6% Gel Spacer
20 lbs./bbl. National Premium Gold 30 bbl.

Lead Slurry		
NeoCem TM	Fluid Weight:	11.8 lbs./gal
12.79 Gal/sk Fresh Water	Slurry Yield:	2.224 ft3/sack
	Total Mixing Fluid:	12.79 gal/sk
	Calculated Volume:	109 bbl
	Proposed Volume:	109 bbl
	Top of Fluid:	0 ft
	Calculated Fill:	1000 ft
	Calculated Sack:	275.06 sack
	Proposed Sack:	276 sack
	Excess:	30% over caliper volume

Tail Slurry		
NeoCem TM	Fluid Weight:	13.6 lbs./gal
9.34 Gal/sk Fresh Water	Slurry Yield:	1.762 ft3/sack
	Total Mixing Fluid:	9.34 gal/sk
	Calculated Volume:	43.2 bbl
	Proposed Volume:	43.2 bbl
	Top of Fluid:	1000 ft

Calculated Fill:	400 ft
Calculated Sack:	137.65 sack
Proposed Sack:	138 sack
Excess:	10% over caliper volume

Note: Volumes above based on 30% excess over gauge hole volumes. Actual cement volumes will be based on open-hole caliper volume + 30% excess. More excess may be added based on hole conditions. Cement blends may be modified to suit actual well conditions.

Attachment C

III. Proposed Well Completion

Appendix I

TAM International

Completion and Running Procedure

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS

OUTER CASING

Component Descriptio	Part #	OD (in)	ID (in)	Length (ft)	Comments	Material		
7.00" Port Collar	700-PC-01	8.25	6.18	2	7.00" LTC Box x Pin	L80		
7.00 " LONGCAP	700-LC-01	8.06	6.18	12	7.00" LTC Box x Pin	L80		
Crossover A		8.25	8.00	1	7" LTC Box x 7" Fiberglass Pin	L80		
7.00" Fiberglass Casing		TBA	TBA	1,300		FG		
Crossover B		8.25	6.18		7.00" FG Box x 8.452 SA Box	C276		
5.90" ID " PBR		8.25	5.90	20	5.90" honed ID, ????" SA Pin x	C276		
Crossover C		8.25	5.90	1	????? SA box x Box	C276		
6 5/8"" LONGCAP	663-LC-01 - H	8.06	5.90	12	TBA SA Pin x Pin	C276	HONED	with viton elastomer
Re-Entry Guide	TW-0794-32	8.25	6.18	1	????? SA Box x re-entry profile	C276	TOGETHER	
	5							

INNER STRING

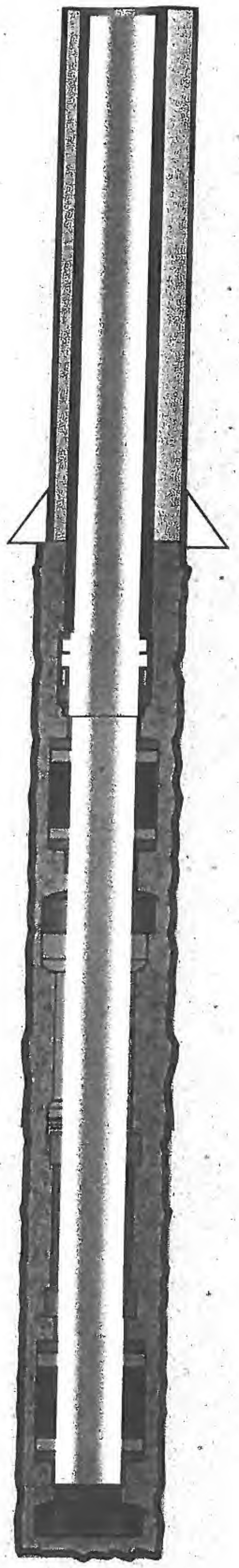
Component Descriptio	Part #	OD (in)	ID (in)	Length (ft)	Comments	
Wellhead Landing Joint		3.50	2.94	20	3 1/2" SA pin down	C276
Crossover Coupling		4.50	3.00	1	3 1/2" SA Box x 3 1/2" FG Pin	C276
Fiberglass Tubing		4.75	2.94	2,700		FG
Fiberglass No-Go Joint		6.00	3.00	30	Built on FG Joint	FG
Seal Body with 5.90 seals		5.90	3.00	6	3 1/2" FG Box x 3 1/2" FG Box	C276
Mule Shoe Extension		4.50	3.00	25	Box cut off - mule shoe - pin up	FG

Service String - 7.00" Combo Tool for operating 7.00" PC versus drill out oc DV tool option

Crossover Sub		Workstring connection by 3 1/2" IF pin
7" Combo Tool	700-CT-05	7" Combo Tool 29 ppf cups 3 1/2" IF box by pin
4 3/4" Choke Sub	475-CH-01	Choke Sub 3 1/2" IF Box by Pin
Crossover Sub		3 1/2" IF by workstring pin
Tubing		
Crossover Sub		Workstring Connection to 5.90" Seal Assembly
5.90" Service Seal Assembly		5.90" Service seal assembly
Ball Catcher Sub		
Tail pipe		

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS



1. Pick up assembly and run in the hole with packers and port colarr spaced out as required.

2. Break circulation to clean up wellbore before cementing

7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS

7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

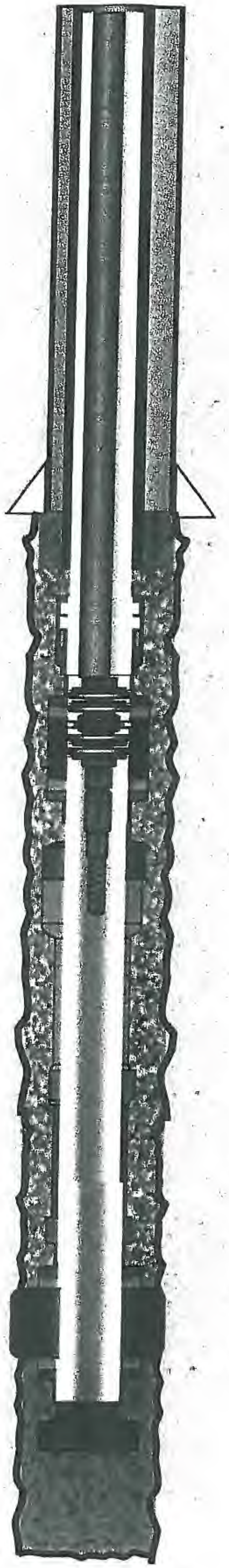
20 ft. PBR C276

Combo Coupling C276

6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

3. Run inner string with seal assembly, sting into lower packer
4. Break circulation, mix & pump calculated volumecement
5. Drop ball behind cement, land in choke sub
6. Increase pressure, inflate Longcap
7. Shear out choke, pooh



TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS

7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

8. Pick up 7" Combo Tool position across Longcap

9. Drop ball for choke sub, test combo tool

10. Inflate Longcap

11. Pick up locate Port Collar

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS

7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

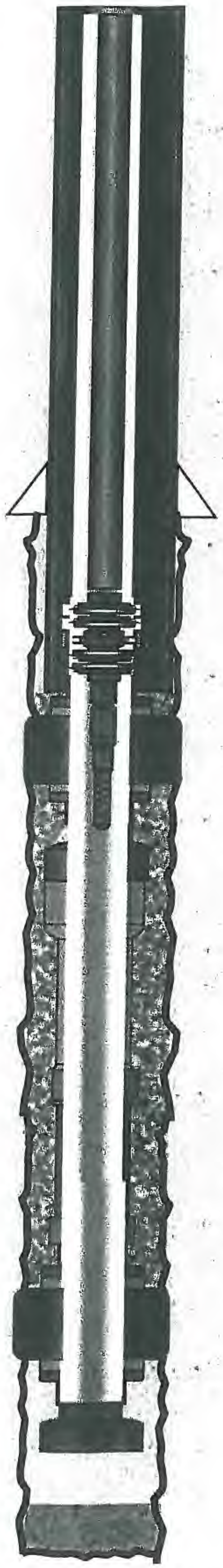
6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

12. Slack off open Port Collar
13. Circulate cement out and condition hole
14. Perform 2nd stage cement job

TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS



7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

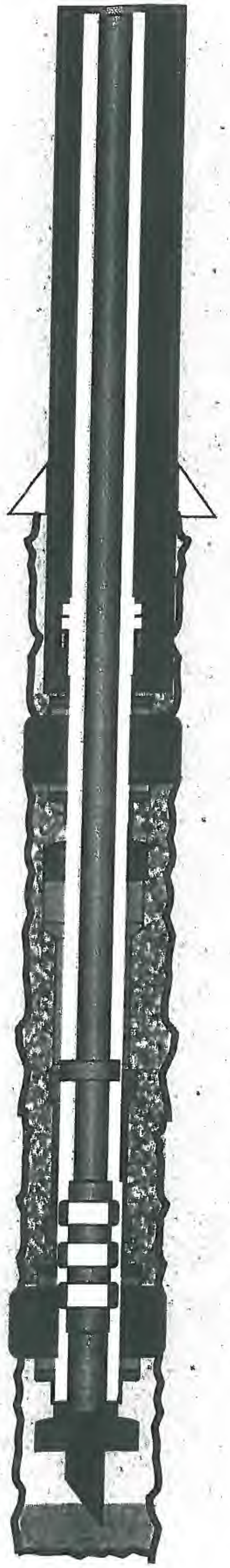
6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

15. Close Port Collar, test Port Collar

16. Reverse out

17. Pooh



TAM INTERNATIONAL

TWO - CHEM WASTE, VICKERY, OHIO
NEW DRILLED CLASS 1 INJECTOR COMPLETIONS

18. Run seal assembly and tubing

7.00" 23 ppf., N80 Casing to surface

680' 13 3/8" Casing, 54.5 ppf. J or K

7.00" Port Collar 23 pp0f., L80 LTC box by pin

7.00" Longcap, 23 ppf. L80 LTC

Crossover Sub 7.00" LTC box by 7 5/8" LTC L80 grade

1600 ft. 7 5/8" Blue Box 2000 psi, 7 5/8" LTC

Combo Coupling C276 7 5/8" LTC boc by TBA Stub Acme box

20 ft. PBR C276

Combo Coupling C276

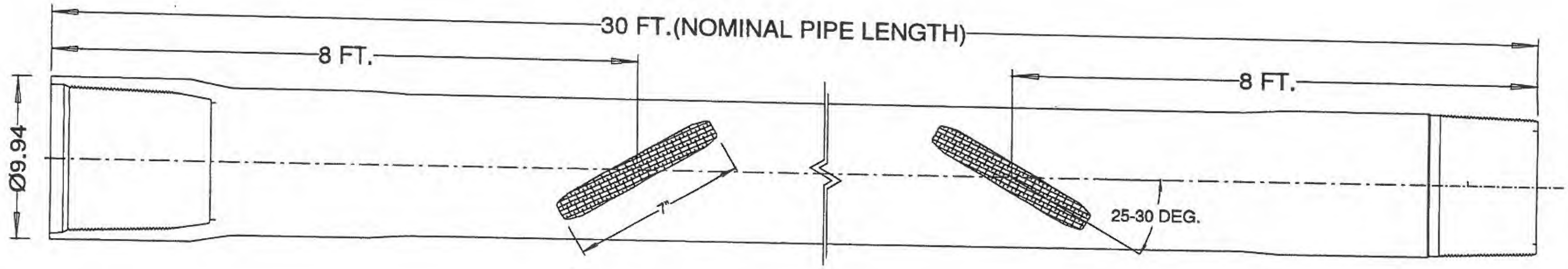
6 5/8" C276 Hastalloy LONGCAP, w/built up viton element,

BTM TAMCAP 2800 FT.

Appendix II

Future Pipe Industries

External Casing Centralizer



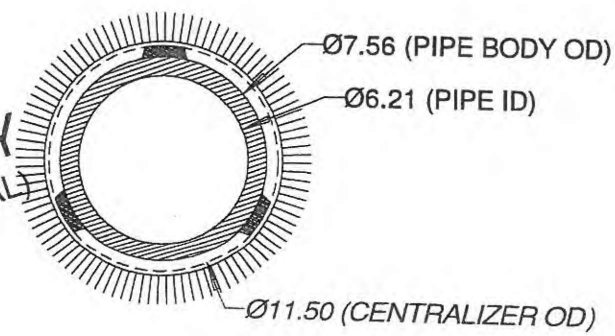
7-5/8 BB 2500

BOX OD=9.94
BODY OD=7.56

7-5/8" CASING LONG THREAD
(FPI 7-5/8 BB 2500)

L4=4.125
E1=7.524
M=0.709
A=3.5 THREAD TURN
8-RD, 3/4 TPF

CENTRALIZER OD=11.50
(CLEARANCE OD 11-3/4)
2 SETS OF 3 BLADES
8 FT FROM THE END



PRELIMINARY
(HOLD FOR APPROVAL)

PREPARE FOR T.W.O. (7-5/8 BB 2500 WITH CENTRALIZER)
QUOTE 62.N.01.18.07

*DO NOT SCALE

UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES	Drawn By: DT	MM/DD/YY 01/09/18	FPI FUTURE PIPE INDUSTRIES
	Checked By:		CENTRALIZER 7-5/8 BB 2500
Material Type:	Approved By:		
Finish Type or Method:	Revision 1:		
	Revision 2:		Drwg Number: 62/PRODUCT/7-5/8 BB 2500 CENT.
	Revision 3:		Revision:

Part Number:

Appendix III

Materials Specifications

FUTURE PIPE INDUSTRIES

Technical Data Sheet

(Single Product Format)

2-7/8" BLUE BOX 2500 8Rd

FIBREGLASS CASING AND TUBING
AROMATIC AMINE CURED EPOXY RESIN

V17.25 (Oct-04-2017)

DIMENSIONAL SPECIFICATIONS

Nom. Size (in.)	Rating (psi)	Nom. I.D. (in.)	Nom. I.D. (mm)	Nom. O.D. (in.)	Nom. O.D. (mm)	Nom Box O.D. (IJ) (in.)	Nom Box O.D. (IJ) (mm)	Drift Diameter (in.)	Drift Diameter (mm)
2-7/8	2500	2.47	62.6	3.04	77.2	4.06	103.2	2.37	60.3

Tolerance on Nom. Box O.D. is +/- 0.10" up to 9-5/8"; +/- 0.15" above 9-5/8"

THREAD DETAILS

Nom. Size (in.)	Thread	Joint Short Code	Connection Type	FPi Connection Code	Ends
2-7/8	2-7/8	AW	2-7/8" 8Rd EUE Long IJ	0278-EUE-LONG-A8	IJ

Nom. Size (in.)		Pitch (E1) (in.)	Pitch (E1) (mm)	L4 (in.)	L4 (mm)	D4 (in.)	D4 (mm)	Pin Upset O.D. (in.)	Pin Upset O.D. (mm)
2-7/8		3.008	76.4	2.875	73.0	3.094	78.6	3.194	81.1

Thread lengths may exceed API L4.

Rd = Round thread per inch, EUE = External-Upset Ends, Csg = Casing, IJ = Integral Joint, TC = Threaded & Coupled

PERFORMANCE AND RATINGS -60F (-50c) to +150F (65c)

Nom. Size (in.)		Design Pressure (psi)	Design Pressure (bar)	Factory Hydrotest Pressure (psi)	Factory Hydrotest Pressure (bar)	Max. Field Test Pressure (psi)	Max. Field Test Pressure (bar)	Collapse Rating (psi)	Collapse Rating (bar)
2-7/8		2500	172.4	3250	224.1	2500	172.4	2900	200.0

Factory and field test pressure may be reduced for certain casing applications and for some turndown box products.

Nom. Size (in.)		Min. Bend Radius (ft)	Min. Bend Radius (m)	Axial Tensile Rating (uniaxial) (lbs)	Axial Tensile Rating (uniaxial) (kN)	Axial Tensile Rating (biaxial) (lbs)	Axial Tensile Rating (biaxial) (kN)	Nom. Wgt (lb/ft)	Nom. Wgt (kg/m)
2-7/8		150	46	22,500	5.1	22,500	5.1	2.0	3.0

Standard de-rating factors: 203F (95c), 0.88; 212F (100c), 0.81; 230F (110c), 0.66; 250F (121c), 0.50

MECHANICAL AND PHYSICAL PROPERTIES

Pipe Body Properties	<=10-3/4	>=11-3/4		<=10-3/4	>=11-3/4	
Tensile Strength, Hoop	31,300	40,000	psi	216	276	MPa
Tensile Strength, Axial (biaxial loading)	30,000	20,000	psi	207	138	MPa
Tensile Strength, Axial (uniaxial loading)	30,000	9,400	psi	207	65	MPa
Axial Modulus	2.5	1.5	10^6 psi	17.2	10	GPa
Specific Gravity	1.93	1.93	---	1.93	1.93	---
Density	0.07	0.07	lb/in3	1.94	1.94	g/cm3
Thermal Conductivity	2.4	2.4	Btu-in./(hr-ft2-F)	0.0035	0.0035	W-cm/(cm2-C)
Thermal Expansion Coefficient (Linear)	0.000011	0.000012	in./in./F	0.000020	0.000022	cm/cm/C
Flow Factor (Hazen Williams)	150	150	---	150	150	---

FUTURE PIPE INDUSTRIES

Technical Data Sheet

(Single Product Format)

3-1/2" BLUE BOX 2500 8Rd

FIBREGLASS CASING AND TUBING
AROMATIC AMINE CURED EPOXY RESIN

V17.25 (Oct-04-2017)

DIMENSIONAL SPECIFICATIONS

Nom. Size (in.)	Rating (psi)	Nom. I.D. (in.)	Nom. I.D. (mm)	Nom. O.D. (in.)	Nom. O.D. (mm)	Nom Box O.D. (IJ) (in.)	Nom Box O.D. (IJ) (mm)	Drift Diameter (in.)	Drift Diameter (mm)
3-1/2	2500	3.00	76.1	3.68	93.4	4.97	126.3	2.90	73.7

Tolerance on Nom. Box O.D. is +/- 0.10" up to 9-5/8"; +/- 0.15" above 9-5/8"

THREAD DETAILS

Nom. Size (in.)	Thread	Joint Short Code	Connection Type	FPI Connection Code	Ends
3-1/2	3-1/2	BH	3-1/2" 8Rd EUE Long IJ	0312-EUE-LONG-A8	IJ

Nom. Size (in.)		Pitch (E1) (in.)	Pitch (E1) (mm)	L4 (in.)	L4 (mm)	D4 (in.)	D4 (mm)	Pin Upset O.D. (in.)	Pin Upset O.D. (mm)
3-1/2		3.664	93.1	3.125	79.4	3.750	95.3	3.850	97.8

Thread lengths may exceed API L4.

Rd = Round thread per inch, EUE = External-Upset Ends, Csg = Casing, IJ = Integral Joint, TC = Threaded & Coupled

PERFORMANCE AND RATINGS -60F (-50c) to +150F (65c)

Nom. Size (in.)		Design Pressure (psi)	Design Pressure (bar)	Factory Hydrotest Pressure (psi)	Factory Hydrotest Pressure (bar)	Max. Field Test Pressure (psi)	Max. Field Test Pressure (bar)	Collapse Rating (psi)	Collapse Rating (bar)
3-1/2		2500	172.4	3250	224.1	2500	172.4	2900	200.0

Factory and field test pressure may be reduced for certain casing applications and for some turndown box products.

Nom. Size (in.)		Min. Bend Radius (ft)	Min. Bend Radius (m)	Axial Tensile Rating (uniaxial) (lbs)	Axial Tensile Rating (uniaxial) (kN)	Axial Tensile Rating (biaxial) (lbs)	Axial Tensile Rating (biaxial) (kN)	Nom. Wgt (lb/ft)	Nom. Wgt (kg/m)
3-1/2		182	55	30,500	6.9	30,500	6.9	3.0	4.4

Standard de-rating factors: 203F (95c), 0.88; 212F (100c), 0.81; 230F (110c), 0.66; 250F (121c), 0.50

MECHANICAL AND PHYSICAL PROPERTIES

Pipe Body Properties	<= 10-3/4	>= 11-3/4		<= 10-3/4	>= 11-3/4	
Tensile Strength, Hoop	31,300	40,000	psi	216	276	MPa
Tensile Strength, Axial (biaxial loading)	30,000	20,000	psi	207	138	MPa
Tensile Strength, Axial (uniaxial loading)	30,000	9,400	psi	207	65	MPa
Axial Modulus	2.5	1.5	10^6 psi	17.2	10	GPa
Specific Gravity	1.93	1.93	---	1.93	1.93	---
Density	0.07	0.07	lb/in3	1.94	1.94	g/cm3
Thermal Conductivity	2.4	2.4	Btu-in./(hr-ft2-F)	0.0035	0.0035	W-cm/(cm2-C)
Thermal Expansion Coefficient (Linear)	0.000011	0.000012	in./in./F	0.000020	0.000022	cm/cm/C
Flow Factor (Hazen Williams)	150	150	---	150	150	---

FUTURE PIPE INDUSTRIES

Technical Data Sheet

(Single Product Format)

7-5/8" BLUE BOX 2500 C 8Rd

FIBREGLASS CASING AND TUBING
AROMATIC AMINE CURED EPOXY RESIN

V17.25 (Oct-04-2017)

DIMENSIONAL SPECIFICATIONS

Nom. Size (in.)	Rating (psi)	Nom. I.D. (in.)	Nom. I.D. (mm)	Nom. O.D. (in.)	Nom. O.D. (mm)	Nom Box O.D. (IJ) (in.)	Nom Box O.D. (IJ) (mm)	Drift Diameter (in.)	Drift Diameter (mm)
7-5/8	2500-C	6.21	157.6	7.56	191.9	9.94	252.5	6.11	155.2

Tolerance on Nom. Box O.D. is +/- 0.10" up to 9-5/8"; +/- 0.15" above 9-5/8"

THREAD DETAILS

Nom. Size (in.)	Thread	Joint Short Code	Connection Type	FPI Connection Code	Ends
7-5/8	7-5/8	GJ	7-5/8" 8Rd CSG Long IJ	0758-CSG-LTC-B8	IJ

Nom. Size (in.)		Pitch (E1) (in.)	Pitch (E1) (mm)	L4 (in.)	L4 (mm)	D4 (in.)	D4 (mm)	Pin Upset O.D. (in.)	Pin Upset O.D. (mm)
7-5/8		7.524	191.1	4.125	104.8	7.625	193.7	7.725	196.2

Thread lengths may exceed API L4.

Rd = Round thread per inch, EUE = External-Upset Ends, Csg = Casing, IJ = Integral Joint, TC = Threaded & Coupled

PERFORMANCE AND RATINGS -60F (-50c) to +150F (65c)

Nom. Size (in.)		Design Pressure (psi)	Design Pressure (bar)	Factory Hydrotest Pressure (psi)	Factory Hydrotest Pressure (bar)	Max. Field Test Pressure (psi)	Max. Field Test Pressure (bar)	Collapse Rating (psi)	Collapse Rating (bar)
7-5/8		2000	137.9	2600	179.3	2000	137.9	2900	200.0

Factory and field test pressure may be reduced for certain casing applications and for some turndown box products.

Nom. Size (in.)		Min. Bend Radius (ft)	Min. Bend Radius (m)	Axial Tensile Rating (uniaxial) (lbs)	Axial Tensile Rating (uniaxial) (kN)	Axial Tensile Rating (biaxial) (lbs)	Axial Tensile Rating (biaxial) (kN)	Nom. Wgt (lb/ft)	Nom. Wgt (kg/m)
7-5/8		375	114	83,500	18.8	83,500	18.8	12.6	18.7

Standard de-rating factors: 203F (95c), 0.88; 212F (100c), 0.81; 230F (110c), 0.66; 250F (121c), 0.50

MECHANICAL AND PHYSICAL PROPERTIES

Pipe Body Properties	<= 10-3/4	>= 11-3/4		<= 10-3/4	>= 11-3/4	
Tensile Strength, Hoop	31,300	40,000	psi	216	276	MPa
Tensile Strength, Axial (biaxial loading)	30,000	20,000	psi	207	138	MPa
Tensile Strength, Axial (uniaxial loading)	30,000	9,400	psi	207	65	MPa
Axial Modulus	2.5	1.5	10^6 psi	17.2	10	GPa
Specific Gravity	1.93	1.93	---	1.93	1.93	---
Density	0.07	0.07	lb/in3	1.94	1.94	g/cm3
Thermal Conductivity	2.4	2.4	Btu-in./(hr-ft2-F)	0.0035	0.0035	W-cm/(cm2-C)
Thermal Expansion Coefficient (Linear)	0.000011	0.000012	in./in./F	0.000020	0.000022	cm/cm/C
Flow Factor (Hazen Williams)	150	150	---	150	150	---

Chemical Resistance Guide Tables

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Acetic Acid 10%	150	200
Acetic Acid-75%	100	120
Acetic Acid-Glacial	NR	NR
Acetone	NR	120
Acrylic Acid	NR	100
Adipic Acid, Solution	200	200
Air	210	230
Alcohol, Ethyl	150	150
Alcohol, Isopropyl	150	150
Alcohol, Methyl	150	150
Alcohol, Methyl Isobutyl	150	150
Alcohol, Secondary Butyl	150	150
Allyl Chloride	100	100
Aluminum Chloride	200	230
Aluminum Fluoride	100	150
Aluminum Hydroxide	100	150
Aluminum Nitrate	200	230
Aluminum Sulfate	200	230
Alum	200	230
Ammonia Gas-Dry	150	230
Ammonia-Wet	NR	100
Ammonium Carbonate	100	150
Ammonium Chloride	200	230
Ammonium Fluoride-25%	100	150
Ammonium Hydroxide-10%	100	150
Ammonium Hydroxide-28%	NR	100
Ammonium Nitrate	200	230
Ammonium Persulfate	NR	100
Ammonium Phosphate	150	150
Ammonium Sulfate	200	230
Amyl Acetate	NR	100
Amyl Chloride	NR	100
Aniline	NR	100
Barium Carbonate	200	230
Barium Chloride	200	230
Barium Hydroxide-10%	200	230
Barium Sulfate	200	230
Barium Sulfide	200	230

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Benzene	100	150
Benzene Sulfonic Acid	NR	100
Benzoic Acid	NR	100
Borax	200	230
Boric Acid	150	200
Bromic Acid	100	150
Bromine	NR	NR
Butadine	100	100
Butane	100	100
Butyl Acetate	NR	100
Butyl Cellosolve	150	150
Butyric Acid-50%	150	150
Calcium Bisulfite	200	200
Calcium Carbonate	200	230
Calcium Chlorate	200	200
Calcium Chloride	200	230
Calcium Hydroxide-50%	200	200
Calcium Hypochlorite-20%	NR	NR
Calcium Nitrate	200	230
Calcium Sulfate	200	230
Carbon Bisulfide	NR	NR
Carbon Dioxide	200	230
Carbon Tetrachloride	100	150
Carbonic Acid	150	200
Castor Oil	200	200
Chlorine	NR	NR
Clorinated Water 0-3000 Ppm	150	230
Chloroacetic Acid-25%	100	120
Chlorobenzene	100	150
Chloroform	NR	100
Chromic Acid-10%	NR	150
Chromic Fluoride	NR	100
Citric Acid	200	230
Copper Chloride	200	230
Copper Fluoride	200	230
Copper Nitrate	200	230
Copper Sulfate	200	200
Crude Oil-Sour, Sweet	200	230

* Green Box™ chemical grade line pipe and Blue Box® chemical grade tubing and casing Products are offered with Nexus Liner

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Diacetone Alcohol	150	150
Dimethylamine	NR	NR
O-Dichlorobenzene	100	150
Dichloroethylene	NR	100
Diethylene Triamine	NR	NR
Ethyl Acetate	NR	150
Ethyl Cellosolve	NR	100
Ethyl Chloride	NR	100
Ethyl Ether	NR	100
Ethyl Chlorohydrin	NR	NR
Ethyl Diamine	NR	NR
Ethyl Glycol	200	200
Ethylene Oxide	NR	NR
Fatty Acids	200	200
Ferric Chloride	150	230
Ferric Nitrate	200	230
Ferric Sulfate	200	200
Ferrous Chloride	200	230
Ferrous Sulfate	200	200
Fluorosilicic Acid-10%	200	200
Formaldehyde-40%	NR	100
Formic Acid-25%	NR	100
Freon	NR	150
Gas-Natural	200	230
Gasoline-Sour	200	230
Gasoline-Refined, All Grades	150	150
Glucose	200	230
Glycerine	200	230
Glycol, Ethylene	200	200
Glycol, Propylene	200	230
Heptane	150	150
Hexane	NR	100
Hexylene Glycol Alcohol	150	150
Hydraulic Fluid	200	200
Hydrobromic Acid-50%	NR	150
Hydrochloric Acid-35%	100	150
Hydrocyanic Acid-10%	NR	NR
Hydrofluoric Acid	NR	NR
Hydrogen	150	150
Hydrogen Peroxide-10%	NR	150
Hydrogen Peroxide-30%	NR	75
Hydrogen Sulfide	150	200
Hypochlorous Acid-10%	200	200
Jet Fuel	150	200

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Kerosene	200	230
Lactic Acid	150	200
Lauric Acid	200	200
Lead Acetate	200	230
Levulinic Acid-25%	200	200
Magnesium Carbonate	200	230
Magnesium Chloride	200	230
Magnesium Hydroxide	120	200
Magnesium Nitrate	200	230
Magnesium Sulfate	200	230
Maleic Acid	150	150
Mercury	200	230
Methane	200	230
Methyl Ethyl Ketone	NR	100
Methyl Isobutyl Carbitol	NR	100
Methyl Isobutyl Ketone	100	150
Mineral Oils	200	230
Naptha	200	200
Napthalene	150	150
Natural Gas	200	230
Nickel Chloride	200	230
Nickel Nitrate	200	200
Nitric Acid-10%	NR	100
Oil, Sour, Crude	200	230
Oleic Acid	200	200
Oxalic Acid	200	200
Perchloric Acid-70%	NR	100
Phenol-5%	NR	150
Phosphoric Acid-50%	NR	150
Phosphorous Pentoxide-50%	NR	100
Pickling Acid	NR	120
Plating Solution	200	230
Potassium Bicarbonate	200	230
Potassium Bromide	200	200
Potassium Carbonate	200	230
Potassium Chloride	200	230
Potassium Dichromate	200	230
Potassium Hydroxide	100	200
Potassium Nitrate	200	230
Potassium Permanganate-5%	150	200
Potassium Permanganate-10%	NR	150
Potassium Sulfate	150	200
Propane	100	100

* Green Box™ chemical grade line pipe and Blue Box® chemical grade tubing and casing Products are offered with Nexus Liner

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Silicic Acid	200	200
Silver Nitrate	200	200
Sodium Acetate	200	200
Sodium Bicarbonate	200	230
Sodium Bisulfate	200	230
Sodium Bromide	200	200
Sodium Carbonate	150	200
Sodium Chlorate	200	230
Sodium Chloride	200	230
Sodium Cyanide	200	230
Sodium Dichromate	200	230
Sodium Ferrocyanide	200	230
Sodium Fluoride	200	230
Sodium Hydroxide	100	150
Sodium Hypochlorite	NR	NR
Sodium Methoxide-40%	100	150
Sodium Nitrate	200	230
Sodium Peroxide	NR	75
Sodium Phosphate	200	200
Sodium Silicate	150	150
Sodium Sulfate	200	230
Sodium Sulfite	200	200
Sodium Thiosulfate	150	150

CHEMICAL	Max Operating Temperature F°	
	Without Liner	With Liner*
Stannic Chloride	200	230
Stearic Acid	150	150
Sulfur Dioxide	NR	150
Sulfuric Acid-25%	NR	150
Sulfuric Acid-70%	NR	100
Sulfurous Acid-5%	NR	150
Tannic Acid	200	200
Tartaric Acid	200	230
Toluene	NR	150
Trichloroacetic Acid	NR	NR
Trichloroethylene-100%	100	150
Triethylamine	NR	100
Trisodium Phosphate	150	150
Turpentine	NR	100
Urea	150	150
Vinyl Acetate	NR	150
Water-Distilled, Deionized	200	230
Water-Fresh, Ph 2-13	200	230
Water-Salt, Brine	200	230
Xylene	150	150
Zinc Chloride	200	230
Zinc Sulfate	200	230

* Green Box™ chemical grade line pipe and Blue Box® chemical grade tubing and casing Products are offered with Nexus Liner

Megamex is a metal supplier for hastelloy, monel, inconel, stainless steel, carbon steel, metal fabrication, nickel alloys, and more.

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INCOLOY® 825

UNS Number N08825

Other common names: Alloy 825, Inconel® 825

Incoloy 825 is a nickel-iron-chromium alloy with additions of molybdenum, copper and titanium. This nickel steel alloy's chemical composition is designed to provide exceptional resistance to many corrosive environments. It is similar to alloy 800 but has improved resistance to aqueous corrosion. It has excellent resistance to both reducing and oxidizing acids, to stress-corrosion cracking, and to localized attack such as pitting and crevice corrosion. Alloy 825 is especially resistant to sulfuric and phosphoric acids. This nickel steel alloy is used for chemical processing, pollution-control equipment, oil and gas well piping, nuclear fuel reprocessing, acid production, and pickling equipment.

In what forms is Incoloy 825 available at Mega Mex?

- Sheet
- Plate
- Bar
- Pipe & Tube (welded & seamless)
- Fittings (i.e. flanges, slip-ons, blinds, weld-necks, lapjoints, long welding necks, socket welds, elbows, tees, stub-ends, returns, caps, crosses, reducers, and pipe nipples)
- Weld Wire (AWS Classification: ERNiFeCr-1 y ENiCrMo-3)
- Wire

What are the characteristics of Incoloy 825?

- Excellent resistance to reducing and oxidizing acids
- Good resistance to stress-corrosion cracking
- Satisfactory resistance to localized attack like pitting and crevice corrosion
- Very resistant to sulfuric and phosphoric acids
- Good mechanical properties at both room and elevated temperatures up to approximately 1000° F

- Permission for pressure-vessel use at wall temperatures up to 800°F

Alloy 825 (UNS N08825) Chemical Composition, %

Ni	Fe	Cr	Mb	Cu	Ti	C	Mn	S	Si	Al
38.0-46.0	22.0 min	19.5-23.5	2.5-3.5	1.5-3.0	.6-1.2	0.05 max	1.0 max	0.03 max	0.5 max	0.2 max

Corrosion Resistance

Alloy 825 has a high level of corrosion resistance. It resists general corrosion, pitting, crevice corrosion, intergranular corrosion, and stress-corrosion cracking in both reducing and oxidizing environments.

In what applications is Incoloy 825 used?

- Chemical Processing
- Pollution-control
- Oil and gas well piping
- Nuclear fuel reprocessing
- Components in Pickling equipment like heating coils, tanks, baskets and chains
- Acid production

ASTM Specifications

Pipe Smls	Pipe Welded	Tube Smls	Tube Welded	Sheet/Plate	Bar	Forging	Fitting
B423				B424	B425	B564	B366, B564

General Mechanical Properties

Tensile (ksi)	.2% Yield (ksi)
85	30-35

Alloy 825 has good mechanical properties from cryogenic temperatures to moderately high temperatures. However, exposure to temperatures above 1000° F can result in microstructural changes that significantly lower ductility and impact strength. Alloy 825 should not be used at temperatures where creep-rupture properties are design factors.

Request a Quote

- **All Alloys**
- **Nickel**
  - Nickel 200/201
- **Hastelloy**
  - Hastelloy B-2

- Hastelloy B-3
- Hastelloy C-22
- Hastelloy C-276
- Hastelloy X

- **Monel**
  - Monel 400
  - Monel K500
  - Monel R-405
- **Incoloy**
  - Incoloy 800H/800HT
  - Incoloy 825
- **Inconel**
  - Inconel 600
  - Inconel 601
  - Inconel 625
  - Inconel 718
- **Nickel Alloys**
  - Alloy C22
  - Alloy C276
  - Alloy 400
  - Alloy 405
  - Alloy 600
  - Alloy 601
  - Alloy 625
  - Alloy 718
  - Alloy 800H/HT
  - Alloy 825
  - Alloy K500
  - Alloy X
  - Alloy B2
  - Alloy B3
  - Alloy 20
- **Stainless Steel**
  - Stainless 253MA
  - Stainless 310
  - Stainless 317L
  - Stainless 321
  - Stainless 330
  - AL-6XN
  - Alloy 20
- **Duplex Stainless**
  - Duplex 2205
  - Super Duplex 2507
  - Zeron 100
  - LDX 2101
- **Carbon Alloys**
- **Line Sheet PDF**

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Megamex is a metal supplier for hastelloy, monel, inconel, stainless steel, carbon steel, metal fabrication, nickel alloys, and more.

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Hastelloy® C-276

UNS Number N10276

Other common names: Alloy C276, Hastelloy C, Inconel® C-276

Hastelloy C276 is a nickel-molybdenum-chromium superalloy with an addition of tungsten designed to have excellent corrosion resistance in a wide range of severe environments. The high nickel and molybdenum contents make the nickel steel alloy especially resistant to pitting and crevice corrosion in reducing environments while chromium conveys resistance to oxidizing media. The low carbon content minimizes carbide precipitation during welding to maintain corrosion resistance in as-welded structures. This nickel alloy is resistant to the formation of grain boundary precipitates in the weld heat-affected zone, thus making it suitable for most chemical process application in an as welded condition.

Hastelloy C-276

Although there are several variations of the Hastelloy nickel alloy, Hastelloy C-276 is by far the most widely used.

Alloy C-276 is widely used in the most severe environments such as chemical processing, pollution control, pulp and paper production, industrial and municipal waste treatment, and recovery of sour natural gas.

In what forms is Hastelloy C276 Available at Mega Mex?

- Bar
- Sheet
- Plate
- Pipe & Tube (welded and seamless)
- Pipe Fittings
- Welding Wire

Corrosion Resistant Hastelloy C276

Considered one of the most versatile corrosion resistant alloys available, Hastelloy C-276 exhibits excellent resistance in a wide variety of chemical process environments including those with ferric and cupric chlorides, hot contaminated organic and inorganic media, chlorine, formic and acetic acids, acetic anhydride, seawater, brine and hypochlorite and chlorine dioxide solutions. In addition, alloy C-276 resists formation of grain boundary precipitates in the weld heat affected zone making it useful for most chemical processes in the as-welded condition. This alloy has excellent resistance to pitting and stress corrosion cracking.

What are the characteristics of Hastelloy C276?

- Excellent corrosion resistance in reducing environments
- Exceptional resistance to strong solutions of oxidizing salts, such as ferric and cupric chlorides
- High nickel and molybdenum contents providing good corrosion resistance in reducing environments
- Low carbon content which minimizes grain-boundary carbide precipitation during welding to maintain resistance to corrosion in heat-affected zones of welded joints
- Resistance to localized corrosion such as pitting and stress-corrosion cracking
- One of few materials to withstand the corrosive effects of wet chlorine gas, hypochlorite and chlorine dioxide

Chemical Composition, %

Ni	Mo	Cr	Fe	W	Co	Mn	C
Remainder	15.0-17.0	14.5-16.5	4.0-7.0	3.0-4.5	2.5 max	1.0 max	.01 max
V	**P**	**S**	**Si**				
.35 max	.04 max	.03 max	.08 max				

In what applications is Hastelloy C-276 used?

- Pollution control stack liners, ducts, dampers, scrubbers, stack-gas reheaters, fans and fan housings
- Flue gas desulfurization systems
- Chemical processing components like heat exchangers, reaction vessels, evaporators, and transfer piping
- Sour gas wells
- Pulp and paper production
- Waste treatment
- Pharmaceutical and food processing equipment

Fabrication with Hastelloy C-276

UNS N10276

Hastelloy C-276 alloy can be forged, hot-upset and impact extruded. Although the alloy tends to work-harden, you can have it successfully spun, deep-drawn, press formed or punched. All of the common methods of welding can be used, although the oxyacetylene and submerged arc processes are not recommended when the fabricated item is for use in corrosion service.

For more information on fabrication and machining click here.

Hastelloy C-276 Welding Material

Alloy C276 welding products are used as matching composition filler material for welding C276 alloy wrought and cast products, for dissimilar welding applications including other nickel-chromium-molybdenum alloys and stainless steels, and for weld overlay or cladding of steels.

Specifiacations: ASME-SFA-5.14 ERNiCrMo-4

Forms of C276 Filler Metal Available at Mega Mex

- .031 in or .8 mm in diameter
- .035 in or .9 mm in diameter
- .039 in or 1.0 mm in diameter
- .045 in or 1.1 mm in diameter
- .047 in or 1.2 mm in diameter
- .062 in or 1.6 mm in diameter
- .078 in or 2.0 mm in diameter
- .093 in or 2.4 mm in diameter
- .125 in or 3.2 mm in diameter

Filler metals are available in spools and in cut lengths from the above diameters. Straight lengths are available in 36" lengths.

ASTM Specifications

Pipe Smls	Pipe Welded	Tube Smls	Tube Welded	Sheet/Plate	Bar	Forging	Fitting	Wire
B622	B619	B622	B626	B575	B574	B564	B366	

Mechanical Properties

Typical Room Temperature Tensile Properties of Annealed Material

Product Form	Tensile (ksi)	.2% Yield (ksi)	Elongation %
Bar	110.0	52.6	62
Plate	107.4	50.3	67
Sheet	115.5	54.6	60
Tube & Pipe	105.4	45.4	70

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Attachment D

Maximum Allowable Bottom Hole Pressure and Maximum Allowable Surface Injection Pressure.

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

BHP_{max} = (Formation Fracture Gradient) (Long String Casing Depth)

BHP_{max} = .75 psi/ft X 2,810' (proposed casing point)

BHP_{max} = 2,107 psi

The maximum allowable surface injection pressure (MASIP) shall be calculated using the following formula:

MASIP = Long String Casing Depth X [Formation Fracture Gradient – (Pressure Gradient of One Foot of Water at 62 Degrees Fahrenheit (.433) X Maximum Specific Gravity (1.00*))]

.75 - .433 = .317

2,810' X .317 = 890.77

MASIP = 890 psi

***If specific gravity over 1.0, MASIP must be adjusted downward accordingly.**

Attachment E

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

Protection of USDW

CORRECTIVE ACTION PLAN AND COMPLIANCE SCHEDULE

Vickery has utilized multiple and redundant search methods to determine the location and status of artificial penetrations of the injection zone within the AOR. A corrective action plan is not required because it has been determined that all artificial penetrations have been properly plugged and abandoned with plugs set such that these wells pose no threat to groundwater due to upward waste migration. Should a corrective action plan be required in the future, it will be proposed in accordance with OEPA guidelines and submitted to OEPA for approval.