7.0 GENERAL SITE REQUIREMENTS

Site requirements for a CTL facility will vary according to the type of materials processed, products manufactured and rated capacity. However, in general, a commercial facility (10,000 – 50,000 barrels per day) will require adequate space to site the processing units and suitable additional acreage to manage the raw materials, intermediate and final products. The site must have:

- Sufficient area for key process units such as the gasifier, gas treatment, FT synthesis and liquid refining, the power block, air separation unit, and hydrogen separation capacity as well as raw material and product storage, transfer, preparation;
- Sufficient water resources for processing and cooling;
- Good transportation facilities to efficiently bring in raw materials and distribute finished products;
- Access to adequate power supply with a path to upload excess power to the grid;
- On-site water treatment, storage and wastewater treatment;
- Sufficient area on site (or proximity to off-site facility) for slag disposal.[3]

The facility will require a minimum of 200 acres of relatively flat land3 for the primary process units and ancillary systems. Additional area would be required if on site slag disposal is contemplated and some buffer space may be necessary to avoid potential impacts to adjoining properties. Therefore optimal conditions would consist of at least 500 – 1000 acres of developable land near the primary resources and infrastructure required to operate the facility.

The primary raw material feedstock is coal. Typically, a barrel of liquid fuel is produced from 0.5 tons of coal.[3] Therefore, a commercial CTL facility will require economical access to approximately 5000 to 25,000 tons per day (tpd) of coal to generate 10,000 to 50,000 bbl/d liquid product. The source of coal may be an adjoining coal mine or coal brought in by rail or barge.

The other primary resource required for operations is water. Water is required create a coal slurry during preparation before gasification. It is also used for cooling, steam generation and other manufacturing processes. CTL facilities can consume 1500 – 2500 gallons per minute[3] and, therefore, require a relatively large and consistent supply of make-up water. For economic reasons, water supply is generally provided by large water bodies such as rivers, well fields located along rivers and large lakes.

8.0 ENVIRONMENTAL AUTHORIZATION REQUIREMENTS

This section of the report has been prepared with emphasis upon federal and state environmental requirements for a generalized or hypothetical coal-to-liquids (CTL) facility located in Kentucky. Most of the requirements are derived from federal statutes and regulations that have been adopted or modified for use in Kentucky, which would be similar to other state requirements. These requirements are presented by general category of regulatory focus (e.g., site planning and development; air emissions; waste management; water supply and discharges; and electric service, generation and transmission).

The CTL facility is presumed to include the following characteristics:

- Construction and operation of a coal gasification plant and F-T liquefaction facility with capacity of 10,000 to 50,000 bbl/d liquid product;
- Construction and operation of the balance of plant and support facilities;
- Construction of a combustion and steam turbine power generating station with the ability to upload excess power to the electrical grid;
- 500 – 1000 acres of relatively flat land;
- Access to up to 25,000 tpd coal and 2500 gpm water;
- Access to transportation infrastructure (rail, roads and/or barge).

Appendix 3 provides a summary of potentially applicable permits and approvals with a brief description of the respective requirements and regulatory agency authority. A discussion of these requirements and their potential affects upon siting and operating a CTL facility follows.

8.1 Site Planning and Development

Site planning and development criteria are essential components of the various environmental permit and authorization requirements for a CTL facility. A discussion of requirements not directly associated with specific authorizations for air emissions, wastewater discharges, waste management or electric generation and transmission is presented in this section.

8.1.1 National Environmental Policy Act (NEPA)

NEPA requires federal agencies to assess the potential environmental impacts of any federal action, including permit decisions. The NEPA process requires extensive public involvement and regulatory agency consultation as well as a thorough analysis of the project purpose, need and alternatives. It includes evaluation of the geographic, social, economic and environmental aspects of the project (and alternatives) to determine the significance of impacts. There are three levels of analysis depending upon the potential for adverse impact to the environment: categorical exclusion (CE); environmental assessment (EA); and environmental impact statement (EIS).

If the CTL facility is funded with federal money or if a permit decision is required by a federal authority, NEPA will apply. Typically in Kentucky, the provisions of NEPA will be imposed as part of federal permitting by the U.S. Army Corps of Engineers for dredging or fill within the waters of the U.S. (Section 404 of the Clean Water Act) or for construction in a navigable water (Section 10 of the Rivers and Harbors Act), such as building barge loading and unloading facilities or water intake structures.

For a potential CTL facility, the primary effect of NEPA will be the extended time and resources required to complete the process (easily 1-3 years or more before a decision to allow construction) and whether a favorable decision can be achieved. Early in the planning process, it is critical to select a site and design the facility to minimize potential impacts. Ideally, this may be accomplished to the extent that NEPA will not apply to the project (i.e., no federal permit decision or funding). This may not be avoidable if the facility will require a US Army Corps of Engineers permit (discussed below).

If NEPA is applicable, it will be necessary provide strong support for the purpose and need for the project. If readily supported and superior to potential alternatives in terms of potential environmental impacts, there is a greater likelihood that the process will be resolved as a CE or require an EA, rather than the more extensive EIS.

8.1.1.1 Influence on Plant Siting, Design and Operation

The project should be located on property that avoids or minimizes impacts to the following:

- Floodplains or wetlands;
- Prime farmland;
- Threatened, endangered or protected species and habitats;
- Significant cultural, historic or archaeological properties or structures;
- Wild and scenic rivers or high quality waters;
- National, state or local parks or recreation areas;
- Impaired water or air resources;
- Nearby residential property, low income or minority neighborhoods or Native American property of interest;

The plant should be designed to minimize the following potential impacts relative to alternative projects and permit requirements:

- Visible and invisible emissions;
- Water quality and consumption;
- Waste generation, toxicity and disposal;
- Noise and surrounding scenery or land use;
- Traffic on roadways, rail or navigable waters;
- Site contamination or release of hazardous materials;
- Natural resources, fish and wildlife

8.1.2 Local Zoning Board or Planning Commission

To avoid potential impacts to densely populated areas and be economically viable, projects of this nature are often sited in rural areas near large bodies of water and coal resources. These types of properties may not be zoned for industrial use or the project may not meet the requirements of a local comprehensive plan for land use in the community. Planning and zoning criteria and administering bodies vary by county and local community across Kentucky.

Properties located in urban areas or densely populated areas that were previously developed for industrial purposes may also present an economic opportunity for constructing a CTL facility. These communities typically have a local planning commission or zoning board and have ordinances restricting land use.

8.1.2.1 Influence on Plant Siting, Design and Operation

Prior to selecting and developing a site, it is incumbent upon the project developer to determine what is the governing entity(ies) for site land use and ensure that the project meets approved zoning and land uses. If not, it will be necessary to pursue a zoning change, modify the local comprehensive plan, or both (ideally prior to property acquisition).

8.2 Air Emissions

Protection and regulation of air quality is primarily derived from the federal Clean Air Act (CAA), its amendments and associated regulations found in Title 40 of the Code of Federal Regulations, Parts 50 - 98. EPA has established nationwide ambient air quality standards for select "criteria" pollutants that must be achieved throughout the country. They have also developed mechanisms to control air quality from new sources of these ambient air quality pollutants as well as additional pollutants, pollutant categories and specific industrial or manufacturing sectors. Management of air quality is achieved through the issuance of air quality permits and standards for control of the types and amount of regulated pollutants.

The federal program for managing air quality is very extensive and complicated. It is not the purpose of this document to discuss the program in detail or describe all potential requirements. A summary of information provided on the EPA's web site [8] of the most likely requirements is presented below.

Title I of the CAA addresses provisions for attaining and maintaining national ambient air quality standards (NAAQS) for select criteria pollutants: ozone (smog), sulfur dioxide, nitrogen oxides, carbon monoxide, particulate matter and lead. Areas that do not meet air standards (nonattainment) are required to implement stricter control of air emission sources in order to achieve standards (Title I, Part D). The Prevention of Significant Deterioration (PSD) program (Title I, Part C and 40 CFR 52.21) is triggered if a new facility is located where NAAQS are maintained (attainment area) and projected emission levels are greater than the PSD major source thresholds. All areas within attainment for one or more of the criteria pollutants are designated Class I, II or III. Class I areas are allowed the smallest incremental pollution increase above baseline concentrations and Class III the largest.

Section 169(a) provides special visibility protection for federal Class I areas, which include national parks and national wilderness areas identified in 40 CFR Part 81, Subpart D.

Title III of the CAA establishes a mechanism for controlling hazardous air pollutants (HAPS) not specifically covered elsewhere in the Act. EPA has published a list of specific HAPs and is required to identify sources of these pollutants and issue maximum achievable control technology (MACT) for each listed source category. MACT must be implemented by applicable sources within a regulated time frame. Applicable regulatory

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[8] "Overview – The Clean Air Act Amendments of 1990" *United States Environmental Protection Agency*. December 19, 2008. http://www.epa.gov/air/caa/caaa_overview.html#titleIII June 25, 2010

requirements include new source performance standards (NSPS) found in 40 CFR Part 60 and national emission standards for hazardous air pollutants (NESHAPs) found in 40 CFR Part 63.

A Title V of the CAA establishes an air permitting mechanism for major sources of air pollution. Air pollution sources subject to the program must obtain an operating permit, states must develop and implement the program, and EPA must issue permit program regulations, review each state's proposed program, and oversee the state's efforts to implement any approved program. Major sources are generally defined as those operating at maximum capacity with the potential to emit (PTE):

- 100 tons or more of a regulated pollutant per year; or
- 10 tons or more of any single specifically identified hazardous air pollutant (HAP) per year; or
- 25 tons or more of any combination of HAPs per year.

New sources of air pollutants from a CTL facility that do not meet the “major” criteria will likely be required to obtain an air permit under different federal or state programs. Section 112(r) of the CAA requires the preparation of a Risk Management Plan (RMP) under the Chemical Accident Prevention Provisions found in 40 CFR 68 (a.k.a. Risk Management Plan Rule). The RMP is used to prevent and mitigate accidental releases of substances that can harm the public and environment from short-term exposures.

Finally, the recent issuance by EPA of the Greenhouse Gas Mandatory Reporting Rule (40 CFR 98) in October 2009 requires certain sources of greenhouse gas (GHG) emissions to perform mandatory monitoring and reporting of GHG emissions.

The USEPA has granted authority for implementing most CAA requirements to Kentucky regulatory authorities. Kentucky requirements are defined in Chapter 224 of the Kentucky Revised Statutes (KRS 224) and Subchapters 10 and 20. Associated air quality regulations are found in Title 401 of the Kentucky Administrative Register (401 KAR), Chapters 50 -53, 55, 57, 59, 60 - 63.

8.2.1 Kentucky Division for Air Quality (DAQ)

EPA has authorized the DAQ to regulate air quality in Kentucky in accordance with the CAA and the federal approved state implementation plan (SIP) regulations found in 40 CFR 52, Subpart S. The DAQ has direct authority for all Kentucky counties except Jefferson County. The DAQ has authorized the Louisville Metro Air Pollution Control District to manage air quality in Jefferson County.

8.2.2 Permitting

All stationary sources emitting air pollutants above minimum thresholds are required to obtain a construction and operating permit as defined in 401 KAR Chapter 52. If the CTL facility will have air emissions below the thresholds identified in Title V of the CAA, a state origin air permit (401 KAR 52:040) will be required. The state thresholds are as follows:

a) Less than 10 tons per year of a single hazardous air pollutant (HAP);
b) Less than 25 tons per year of combined HAPs; and
c) Greater than or equal to 25 tons per year but less than 100 tons per year of any other regulated air pollutant.

A facility that meets these requirements is considered a minor source and the resulting state origin permit is valid for 10 years. Construction for the facility can’t begin until the permit is issued.

A Title V air permit (401 KAR 52:020) is required if the facility exceeds the major source thresholds. The resulting Title V permit is valid for 5 years and construction for the facility can’t begin until the permit is issued.

Typically, a Title V major source permit will have more onerous monitoring and reporting requirements than a state origin permit. In order to avoid some of these requirements, a facility can accept voluntary operating restrictions to reduce emissions below major source levels. The facility would be permitted as a “conditional major source” under 401 KAR 52:030, federally-enforceable permits for non-major sources. This type of permit is valid for 5 years. Construction of new conditional major sources may begin after a draft permit has been issued, but the final permit must be issued before operations can begin.

8.2.2.1 PSD Requirements

In addition to the Title V air permit, the facility may be subject to additional regulatory review under PSD and Nonattainment programs. The PSD program is triggered if a new facility is located where NAAQS are maintained (attainment area) and projected emission levels are greater than the PSD major source thresholds (401 KAR 51:017 and 40 CFR 51.166). A new CTL facility could be a major stationary source under the PSD program based on the thresholds listed below.

a) A fuel conversion plant with a PTE of 100 tons/year or more of any regulated air pollutant;
b) A fossil fuel-fired steam electric plant with more than 250 million BTU/hr of heat input with a PTE of 100 tons/year or more of any regulated air pollutant; or A fossil fuel-fired steam electric plant with less than 250 million BTU/hr of heat input with a PTE of 250 tons/year or more of any regulated air pollutant;
c) A sulfur recovery plant with a PTE of 100 tons/year or more of any regulated air pollutant;
d) A petroleum refinery with a PTE of 100 tons/year or more of any regulated air pollutant;
e) A coal cleaning plant utilizing a thermal dryer with a PTE of 100 tons/year or more of any regulated air pollutant;
f) All other sources with a PTE of 250 tons/year or more of any regulated air pollutant.

If the facility is subject to PSD, it will be required to: perform a detailed analysis of available ambient air quality data (or conduct its own air testing); evaluate and model its anticipated emissions and determine the potential for incremental increases in ambient air quality; and implement best available control technology (BACT) for applicable regulated pollutants. It will also require evaluation of adverse impacts on federal Class I areas (i.e., national parks and national wilderness areas identified in 40 CFR Part 81, Subpart D). Any future modification to the facility would need to be reviewed with respect to increases in regulated pollutants that may trigger additional PSD review. The facility may only begin construction after the combined Title V/PSD major source permit has been issued.

A facility that is a major source under Title V and subject to PSD may accept voluntary operating restrictions that limit emissions to below the PSD or non-attainment thresholds. This permit is considered a Title V Synthetic Minor permit (401 KAR 52:020). The permit is valid for 5 years and the facility can begin construction after the permit has been issued.

8.2.2.2 Nonattainment Area Requirements

The Nonattainment program would be triggered if the facility were a major source of NAAQS regulated pollutants (particulates, sulfur dioxide, carbon monoxide, ozone, nitrogen oxides, and lead) in an area that does not already meet NAAQS for the regulated pollutants emitted (401 KAR 51:052 and 40 CFR 51.165). Attainment status for each county and regulated pollutant is identified in 401 KAR 51:010. According to the most recent version of the state regulations, Boyd County does not meet the primary or secondary standard for sulfur dioxide. Muhlenberg County is listed as not attaining the *secondary* standard for sulfur dioxide. Any new facility located in these counties will need to determine the lowest achievable emission rate (LAER) in accordance with 401 KAR 51:052. This will need to be considered for the design and operation of the facility.

Additionally, Boone County, Kenton County, Campbell County and Jefferson County are identified as moderate for ozone as well as portions of Bullitt and Oldham County. Any new facility located in these counties will need to evaluate Reasonably Available Control Technology (RACT) required by 401 KAR 50:012 and determine the LAER.

The facility may only begin construction after the combined Title V/Nonattainment major source permit has been issued.

A facility may avoid the requirements of the Nonattainment program by not locating in a nonattainment area or by accepting voluntary operating restrictions that limit emissions below applicable major source thresholds. If the facility accepts operating restrictions, it will be permitted as a Title V “synthetic minor source”. The permit is valid for 5 years and the facility can begin construction after the permit has been issued.

8.2.2.3 Federal Class I Areas

Mammoth Cave National Park, located near Bowling Green in Edmonson County is the only federal Class I Area in Kentucky. The closest federal Class I Area outside of Kentucky is the Great Smoky Mountains National Park, southeast of Knoxville, Tennessee. Requirements for pollution control technologies will be more stringent for CTL facilities that may affect visibility in these areas. The primary pollutants that contribute to reduced visibility at these Class I Areas are sulfur dioxide, nitrogen oxides and organic carbon particles (KDOW, June 2008). Each of these pollutants are associated with industrial processes that occur in a typical coal gasification operation.

8.2.2.4 NSPS and NESHAPS Requirements

Regardless of the applicable air permit, a new CTL facility may be subject to both NSPS and NESHAPs requirements, if it meets certain affected facility definitions and processing or throughput limits. These requirements will be incorporated into the permit, if applicable. Possible NSPS standards (40 CFR 60) that may apply to the facility depending upon design and final configuration include:

a) Subpart Da, Electric Utility Steam Generating Units;
b) Subpart KKKK, Stationary Combustion Turbines;
c) Subpart Y, Coal Preparation and Processing Plants
d) Subpart KKK, Onshore Natural Gas Processing: Equipment Leaks
e) Subpart Ja, Petroleum Refineries

Depending on the potential electric output capacity of the facility, the plant will be subject to the NSPS standards found in 40 CFR 60 Subpart Da (Electric Utility Steam Generating Units) or Subpart KKKK (Stationary Combustion Turbines). Subpart Da is applicable if more than one-third of the potential electric output of the facility and more than 25 MW of net electrical output is supplied for sale to any utility power distribution system. If Subpart Da is not applicable, then Subpart KKKK may apply. Each of these standards have requirements for preconstruction review, training, emission and operating limitations, performance testing, monitoring (including continuous emissions monitoring systems), recordkeeping and reporting.

The plant could also be subject to NSPS Subpart Y (Coal Preparation and Processing Plants), Subpart KKK (Onshore Natural Gas Processing: Equipment Leaks) and Subpart Ja (Petroleum Refineries). The coal gasification plant may be subject to NSPS Subpart Y for Coal Preparation Plants since it will process more than 200 tons/day of coal. Subpart Y contains emission and control requirements for thermal dryers; coal cleaning, conveying, storage, transfer, and loading; monitoring (including continuous emissions monitoring devices); testing; reporting; and recordkeeping.

Subpart KKK defines additional requirements for inspections and maintenance, emission limitations, recordkeeping and reporting that need to be met by the plant to limit emissions from equipment leaks, if applicable.

Subpart Ja may apply if the facility will contain fuel gas combustion devices and sulfur recovery plants. This subpart defines specific limitations for particulate matter, carbon monoxide, and sulfur oxides, along with monitoring (including continuous emissions monitoring systems), testing, recordkeeping, and reporting requirements.

The coal gasification facility may also be required to meet the NESHAPs requirements found in 40 CFR 63 Subpart HH (Oil and Natural Gas Production) and Subpart YYYY (Stationary Combustion Turbines), if the facility's combined emissions for HAPs are greater than the major source thresholds of over 10 tons/year for any single HAP and 25 tons/year for all HAPs. The facility must meet certain emission standards reflecting maximum achievable control technology (MACT), work practices, monitoring and performance testing requirements to maintain compliance.

8.2.2.5 GHG Emissions Requirements

The Greenhouse Gas Mandatory Reporting Rule requires affected sources to perform mandatory monitoring and reporting of greenhouse gas (GHG) emissions. GHGs are defined as carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, perfluorochemicals and other fluorinated gases. Carbon dioxide is commonly generated during the combustion of fossil fuel sources and is also created during coal gasification. The rule identifies several particular source categories that must report and defines how they are required to monitor GHGs.

It is likely that a CTL facility will be subject to this rule, possibly qualifying as one of the specific source categories: electricity generation, petroleum refinery (CTL refining), boiler, combustion turbine or other stationary fuel combustion equipment. If so, the facility will need to establish mechanisms for monitoring GHGs in accordance with the methods described in the applicable standards (some for specific source categories) and annually report greenhouse gas emissions to the EPA. This could entail adding additional monitoring devices, calibrating them on a routine basis and maintaining the devices.

If CO_2 capture and sequestration is not contemplated in the facility design, they may need to be considered at a later date as the EPA reviews GHG reporting data and promulgates regulations designed to control GHG emissions. EPA has recently announced that large emitters of GHGs will be required to be permitted and implement best available control technology, possibly as early as 2011. At the time of this writing, EPA had not identified specific sources or GHG emission thresholds requiring a permit, nor permit requirements as of September 2010.

8.2.2.6 Risk Management Plan

Section 112(r) of the CAA requires the preparation of a Risk Management Plan (RMP) under the Chemical Accident Prevention Provisions found in 40 CFR 68 (a.k.a. Risk Management Plan Rule). The RMP is used to prevent and mitigate accidental releases of substances that can harm the public and environment from short-term exposures. A CTL facility may be required to prepare, implement and submit an RMP to EPA if the facility stores any of the listed toxic and flammable substances above the threshold quantities found in 40 CFR §68.130. Substances that could trigger this requirement and may be present at a CTL facility include: ammonia, hydrogen sulfide and sulfuric acid (fuming).

8.2.2.7 Influence on Plant Siting, Design and Operation

Application of the myriad of air pollution control and permitting requirements is largely dependent upon the location of the CTL facility, specific process equipment that will be used and associated operating capacities. A thorough economic cost/benefit analysis is necessary during the planning process to compare CTL production plans having sufficient economic return with corresponding costs required to comply with more stringent requirements as production capacity increases. Additionally, consideration of the project schedule impacts will be required, since the permitting timeframe will increase as more stringent requirements become applicable and are incorporated into the process. Some of the more stringent requirements may be avoided if the facility can be designed and operated profitably under restricted operating scenarios that reduce air emissions to below regulatory thresholds.

A summary of items to consider for planning and operation are identified below.

- Where possible, the facility should not be located within or near a nonattainment area for any NAAQS pollutant. Currently in Kentucky this would be Boyd County (sulfur dioxide), Muhlenberg County (sulfur dioxide); Boone, Kenton, Campbell, Jefferson and portions of Bullitt and Oldham Counties (ozone). If unavoidable, the facility may consider operating restrictions to lower emissions below the major source threshold and not be subject to Nonattainment requirements. Subsequent plans to increase production or change operations that may affect air emissions will also need to be evaluated with respect to applicability of more stringent requirements under this program. Barring that, the facility will need to design and operate the facility to meet LAER and RACT requirements.

- A major source under the PSD program should not be located where it may affect a federal Class I area (i.e., national parks and wilderness areas). Mammoth Cave National Park near Bowling Green, Kentucky and Smokey Mountain National Park near Knoxville Tennessee are the two areas that would be closest to any CTL facility in Kentucky. Any CTL facility that may affect these sites will need to evaluate potential impacts and consider additional control equipment, as well as anticipate additional time for the permit process. The facility may consider operating restrictions to lower emissions below the major source threshold and not be subject to PSD requirements. Subsequent plans to increase production or change operations that may affect air emissions will also need to be evaluated with respect to applicability of more stringent requirements under this program.

- A major source under the PSD program that is located in an attainment area will need to evaluate incremental pollutant capacity and may be required to perform ambient air quality monitoring and modeling to complete this evaluation. Aside from the added cost, this will increase the permit process time frame. Additionally, the facility will need to incorporate Best Available Control Technology (BACT) into the facility design and operate the facility with appropriate BACT (401 KAR 51:017). The facility may consider operating restrictions to lower emissions below the major source threshold and not be subject to PSD requirements. Subsequent plans to increase production or change operations that may affect air emissions will also need to be evaluated with respect to applicability of more stringent requirements under this program.

- During the initial planning and design, process equipment and operating scenarios will need to be evaluated with respect to specific NSPS and NESHAPS standard applicability. If the facility cannot be operated at levels that may preclude these standards, then it may be necessary to incorporate Maximum Achievable Control Technology (MACT) into the design and operate the facility in accordance with standard specific operating, monitoring and reporting requirements.

- With respect to greenhouse gases, the facility will likely be required to track and report GHG emissions. Depending upon the processes and equipment used, there may be specific monitoring equipment and processes that will need to be incorporated into the design and operation of the facility. At present, these are not considered to be too substantial. However, as the EPA evaluates permitting requirements and associated restrictions, it is likely that the facility will need to incorporate CO_2 capture and sequestration technologies into the design of the facility. Since these are emerging technologies, an ideal solution is difficult to develop, but a strategy should be developed in the planning process that considers several leading technologies. Included should be consideration of a location that has suitable infrastructure and subsurface formations that are capable of being used for sequestration.

- If the facility is able to accept operating restrictions that avoid some of the more onerous permitting and pollution control requirements, the facility must ensure that it can stay below permit limits. Any excursion or change in equipment that affects operating capacity and increases air emissions may not only result in a penalty, but may also require modifying the permit, essentially nullifying the advantage of negotiated operating restrictions. An added disadvantage of this scenario is the time it would take to obtain the new permit during which the facility could only operate under the limits of the original permit.

- Regardless of the type of permit, the facility will need to adhere to permit limits and control requirements. Periodic monitoring, inspection, maintenance and reporting will also be required to ensure compliance. Additionally, any deviations from the requirements, including those attributed to upset conditions, must be promptly reported and corrective or preventative measures promptly implemented.

8.3 Waste Management

Waste management requirements for new and operating facilities are primarily derived from the federal Resource, Conservation and Recovery Act (RCRA) and associated amendments and regulations implemented by the USEPA. Since improper management of any waste can have adverse impacts to human health and the environment, aspects of waste generation, storage, treatment, transportation, disposal, recycling and remediation of spills or releases are strictly regulated. Specific requirements are related to the degree of toxicity or hazard a waste may possess. “Hazardous” wastes are more strictly regulated and defined as being on one of four specific hazardous waste lists (F-list, K-List, P-List and U-List) or exhibiting at least one of four hazardous characteristics (i.e., ignitable, corrosive, reactive or toxic). Wastes not meeting these criteria are less strictly regulated and often referred to as “Non-Hazardous”.

Land use activities occurring prior to the implementation of RCRA that have caused site contamination or are associated with past waste practices are often addressed through the requirements of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also referred to as Superfund. This statute and associated amendments and regulations prescribe how contaminated sites will be evaluated and remediated. Contemporary activities that have caused the impact of properties, but were not associated with "Hazardous" waste activities (i.e., not managed under RCRA) can also be addressed through CERCLA and associated amendments and regulations.

The USEPA has granted authority for implementing most RCRA and CERCLA requirements to Kentucky regulatory authorities. Kentucky requirements largely mirror federal requirements. They are defined in Chapter 224 of the Kentucky Revised Statutes (KRS 224) and Subchapters 1, 10, 40, 43, 46, 50, 60 and 80. Associated regulations are primarily found in Title 401 of the Kentucky Administrative Register (401 KAR), Chapters 30 – 49.

8.3.1 Kentucky Division of Waste Management (DWM)

The DWM is the regulatory agency responsible for waste management in Kentucky. Any developer and operator of a CTL facility will likely interact with two Branches of the DWM. The Solid Waste Branch (SWB) is responsible for the review and issuance or denial of permits for solid waste and special waste landfills, land farming and composting facilities and registrations for permit-by-rule facilities – all "Non-Hazardous" wastes.

The Hazardous Waste Branch (HWB) is responsible for regulating the generation, storage, treatment, transportation and disposal of hazardous waste. During construction, start-up and operation of a CTL facility, various wastes will be generated that may be classified as hazardous wastes. The facility will need to manage these materials in compliance with applicable requirements.

8.3.2 Special Waste Permit

The largest solid waste stream produced by a CTL facility is slag from the gasifier. This material is a black, glassy, sand-like material that is potentially a marketable byproduct. Laboratory data for various gasifier slags indicate they would not be classified as a hazardous waste.[7]

As stated above, this material can be marketed for beneficial reuse as an aggregate in asphalt or as blasting grit and roofing granules. If there is no market available, the CTL facility will need to develop plans for disposal. Due to the volume of material, off-site disposal at a conventional landfill may not be as feasible as disposal on site within an appropriately designed, permitted and managed landfill. Coal gasification waste is classified as a special waste in Kentucky (KRS 224.50-760(1)(a)). Waste disposal facilities are required to have a permit (KRS 224.40). Requirements for a special waste landfill are found in regulations contained in 401 KAR Chapters 45, 47 and 48.

Landfills are designed to contain the waste, prevent water from contacting the waste and prevent any liquids contained within to leach out and affect local water resources (i.e., surface and ground water). This is generally accomplished by:

- Minimizing any liquids contained in the waste using a waste drying mechanism;
- Covering the waste with an impermeable clay barrier to minimize contact with precipitation;
- Designing and constructing surface water control measures to prevent flowing water from contacting the waste (i.e., diverting waters around the waste);
- Constructing the landfill with a bottom liner and leachate collection system.

A simplified, conceptual diagram portraying these characteristics is presented in **Figure 2.**

8.3.2.1 Influence on Plant Siting, Design and Operation

To optimize the siting of a landfill and meet the general criteria above, it is important to have sufficient area to contain the amount of slag anticipated to be generated over the life of the project. Ideally, this will be relatively flat land, isolated from any streams or lakes and with seasonal groundwater levels well below the designed bottom of the landfill. Proximity of suitable clay material for cover is also important.

Specific criteria identified by Kentucky regulations are also provided below:

Buffer Zone. Wastes shall not be placed:

- Within 250 feet of an intermittent or perennial stream, unless a water quality certification has been issued allowing the variance;
- Within the zone of collapse of underground mine works or the angle of draw of such works;
- Within 250 feet of a sinkhole or other karst feature;
- Within 100 feet of the property line.

Floodplain. Wastes shall not be placed within the 100-year floodplain, unless the applicant demonstrates that the placement will not impede base flow, water storage capacity and there will be no waste wash out.

Site Suitability. For the landfill location the applicant must demonstrate that:

- The uppermost aquifer can be monitored to detect and release of hazardous substances or pollutants;
- If a groundwater release is detected, corrective action can be performed within the aquifer;

Protected Resources. Similar to NEPA requirements, landfill construction and operation cannot adversely impact the following resources:

- Threatened, endangered or protected species and habitats;
- Significant cultural, historic or archaeological properties or structures;
- National, state or local parks or recreation areas; or
- Wetlands.

Design and operation of the landfill must meet the environmental performance criteria contained in 401 KAR 30:031, which includes avoiding impact to the above referenced protected resources as well as no adverse impact to surface water, groundwater, air quality or food crops. Additionally, the waste site can not pose a safety or public health threat or be a public nuisance. Design and operation must also meet the financial, technical and operating requirements identified at 401 KAR Chapter 45.

Approval of the design for the landfill requires that the design demonstrates that it meets the siting and environmental performance criteria presented above. This must be demonstrated through consideration of at least the following aspects:

- Physical and chemical characteristics of the waste, the hazard that it presents to water or air resources and its compatibility with the liner and cover;
- Suitability of the liner and cover for ensuring the waste will not impact surface water and groundwater;
- Waste volume;
- Climatic conditions;
- Soil properties under the landfill;
- Hydrogeologic characteristics of the site, including quality, quantity, current use and direction of groundwater flow;
- Design of the leachate control system, surface water run-on and run-off control and gas migration control, if needed; and
- Proximity to surface water and groundwater.

An approximate time frame for completing the application and obtaining approval for this permit is 1 – 1.5 years.

Operating criteria include developing costs for an independent party to close the facility and maintaining financial assurance to pay an independent party for closure in the event that the permittee is unable to do so. They also include maintaining the facility, monitoring surface and groundwater to ensure compliance with environmental performance standards and taking corrective action if there is a failure to comply with environmental performance standards.

8.3.3 Hazardous Waste Management

Although available data does not indicate that the slag would be classified as a hazardous waste, there are likely to be several types of wastes generated routinely or on a non-routine basis (equipment startup/shutdown, equipment failure, equipment/facility maintenance) that may be classified as hazardous.

Materials generated from syngas cleaning may be classified as a waste if they are discarded, rather than being reused in the process or sold as a commercial product. Potential hazardous wastes identified at a potential CTL facility in Alaska [9] include:

- Spent filter elements and media, including spent carbon containing mercury;
- Spent catalyst wastes;
- Metals, salts and sludge from wastewater treatment.

These wastes may be characterized as hazardous due to the presence and concentration of toxic metals. EPA in its evaluation of steam electric power generating facilities reported that solids generated from wastewater treatment at the Wabash River

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[9] Alaska Coal Gasification Feasibility Studies – Healy Coal-to-Liquids Plant. Final Report prepared for the U.S. Department of Energy, National Energy Technology Laboratory, DOE/NETL-2007/1251, July 2007.

IGCC facility were characterized as a hazardous waste due to selenium and arsenic concentrations.[10]

Additional types of byproducts or waste materials that may be considered to be a hazardous waste include:

- Spent acids or caustics used for cleaning or generated during acid gas removal and sulfur recovery;
- Sludge or liquids discarded from the FT reactions and refining that may be ignitable or contain toxic impurities above hazardous waste threshold concentrations; and
- Waste paints and clean up solvents.

8.3.3.1 Influence on Plant Siting, Design and Operation

It is essential to confirm whether any waste generated (both routine and non-routine) is classified as hazardous or not to ensure appropriate management and disposal practices. State hazardous management requirements are found at 401 KAR, Chapters 31 – 40.

All hazardous waste management activities require prior notice to the state. Kentucky requires facilities to identify all hazardous wastes generated, register those wastes with the state and obtain an EPA ID number for the site (401 KAR 32:010), consistent with federal requirements. Registration must be obtained before any hazardous waste can be shipped off site for disposal.

There are specific requirements for storage, transportation and disposal of hazardous wastes to minimize the potential for accidental or uncontrolled releases to the environment as well as ensure that they do not accumulate on site. Wastes may be

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[10] Steam Electric Power Generating Point Source Category: Final Detailed Study Report. U.S. Environmental Protection Agency, EPA 821-R-09-008, October 2009.

stored in containers near the point of generation (drums, tanks, totes) or moved to a central storage area or building prior to disposal. Containers and storage areas need to be compatible with the chemical and physical properties of the wastes. Unless a facility generates a substantial volume of hazardous waste, it is generally more practical and feasible to dispose the waste off site at an appropriately permitted and managed facility. Therefore, the primary consideration for on site management is appropriate waste characterization, container management and storage to minimize the potential for spills or releases. It is also necessary to have the appropriate plans, resources and personnel to promptly respond to any emergency.

In the event that the facility generates a large enough volume of hazardous waste that is uneconomical to dispose off-site (reviewed literature does not indicate this is likely) or the facility plans to treat hazardous wastes on site to reduce off-site disposal costs, the facility will need to apply for and receive approval for on-site treatment and disposal activities. Permit requirements are similar to those presented for the Special Waste Disposal facility above, albeit far more comprehensive, costly and time consuming.

8.3.4 Brownfield Developments

Brownfield sites are identified as properties that have been previously developed for industrial or manufacturing purposes. They typically have most of the site characteristics suitable for development of a CTL facility and can provide an economic alternative for site development. However, historic activities may have resulted in site contamination or other environmental impacts that need to be fully characterized and addressed during the site planning process.

8.3.4.1 Influence on Plant Siting, Design and Operation

If choosing to locate on a Brownfields property, it is incumbent upon the developer to confirm whether the site is contaminated and to what extent. It is also important to determine the source of contamination and whether any mandated or desired corrective action will be driven by RCRA or CERCLA.

To avoid acquiring contaminated sites and assuming liability for their clean-up, a Phase I Environmental Site Assessment (Phase I ESA) is generally conducted. In order to legally qualify as an innocent or bona fide purchaser and avoid CERCLA liability, it is necessary to complete the ESA in a manner that conforms with regulations published by the EPA and contained at 40 CFR Part 312 (All Appropriate Inquiry Rule). This involves performing a detailed evaluation of the historical activities on the property (and nearby properties) as well as current operations through: a review of publically available records; a review of regulatory agency permits and files; interviews with past and current operators and occupants; and a thorough site inspection by a qualified environmental professional.

Following completion of the ESA, additional investigation may be conducted that includes site sampling or other methods to identify and delineate the presence of site contamination. This information can then be used to determine whether the site is suitable for project development. If so, the information can be used to develop the property in areas that aren't impacted or incorporate site cleanup into the design and layout of the facility.

8.4 Water Supply and Discharges

Management of water quality is primarily administered by the USEPA under the Clean Water Act (CWA) and associated amendments and regulations. The CWA address wastewater treatment requirements and discharge limits for process wastewaters and sanitary wastewater as well as stormwater impacted by construction and industrial activities. Portions of the CWA also control the quantity and quality of surface waters, groundwater and drinking water. EPA manages these programs through a series of permits, best technology control practices, permit restrictions, monitoring and reporting programs.

The USEPA has granted authority for implementing most CWA requirements to Kentucky regulatory authorities. Kentucky requirements largely mirror federal requirements. They are defined in Chapter 224 of the Kentucky Revised Statutes (KRS 224) and Subchapters 1, 10 and 70 - 73. Associated regulations are primarily found in Title 401 of the Kentucky Administrative Register (401 KAR), Chapters 4 - 11.

8.4.1 U.S. Army Corps of Engineers (USACE)

The USACE is the federal agency responsible for regulating construction within navigable waters of the United States and the discharge of dredged or fill material into “jurisdictional” waters of the United States, including special aquatic sites such as wetlands. The USACE has authority granted under Section 10 of the Rivers and Harbors Act for managing construction within navigable waters. The USACE also has authority (with EPA oversight) for controlling impacts to jurisdictional waters regulated under Section 404 of the CWA. The USACE can authorize activities by a specific individual permit, a general nationwide permit (NWP) or regional permit, and a letter-of-permission. A letter-of-permission or NWP are generally limited to small disturbances of jurisdictional waters, typically < 0.5 acre and likely would not be suitable for a CTL facility.

A CTL facility in Kentucky will fall within one of four USACE districts: Huntington, WV (eastern Kentucky); Louisville, KY (most of KY); Nashville, TN (southeastern and southwestern portions of KY including the Cumberland and Tennessee River basins); and Memphis, TN (far southwestern Kentucky along the Mississippi River).

Areas where a CTL facility may require USACE authorization for construction and operation include:

- constructing or modifying a barge facility on a navigable water;
- constructing a water intake or discharge structure on a navigable water;
- plant site construction affecting rivers, streams, lakes and wetlands; and

- road construction for crossing streams and wetlands.

8.4.1.1 Influence on Plant Siting, Design and Operation

Authorization of any of these types of construction requires the facility to first identify jurisdictional waters on the property to be developed. The USACE requires that a project be designed to avoid or minimize impacts. If the impacts cannot be avoided or minimized, the facility will need to develop a plan to mitigate any impacts. This plan may include new construction projects designed to enhance the quality and quantity of similar water resources within the same general watershed. These types of projects also require long term monitoring and reporting to demonstrate the success of the project. Alternatively, the facility may be able to assess the extent of impact and pay a mitigation fee to an approved group or fund that uses mitigation fees to finance alternative projects to enhance water resources.

If pursuing an individual permit, the project will also need to be reviewed under provisions of the NEPA, as described above. The project will need to have a well substantiated purpose and need statement to justify the identified impacts and review of reasonable, competitive alternatives that show the project to be the preferred alternative with the least impact.

Ideally, a proposed project will be designed and located on property that has no jurisdictional water impacts to avoid permit requirements. However, due to the water requirements (and feasibility of fuel supplied by barge) of these types of projects, this is an unlikely scenario. Depending upon the significance and extent of impact, the permitting process may well take several years (2 - 5), which can be extended if there is considerable public opposition and litigation. Therefore, it is prudent to evaluate any project site early to identify jurisdictional waters and any other protected resources (e.g., threatened & endangered species; cultural and historic resources; minority and low income populations) and design the project to avoid these resources to the greatest extent practical and feasible.

8.4.2 Kentucky Division of Water (DOW)

The DOW is the regulatory agency responsible for managing, protecting and enhancing the quality and quantity of Kentucky waters. It provides authorizations for construction within floodplains and in flowing waters. DOW has requirements for obtaining a permit for water withdrawal as well as wastewater discharges directly to streams. Wastewater discharge permits for process wastewaters and stormwater are managed under the Kentucky Pollutant Discharge Elimination System (KPDES) program. DOW also regulates drinking water supplies.

8.4.3 Stream and Floodplain Construction

The DOW Floodplain Management Section is responsible for approving or denying construction and other activities within the 100-year floodplain of any river or stream in Kentucky, as required by Chapter 151 of the Kentucky Revised Statutes and associated regulations. Construction of CTL processing equipment, buildings, road crossings, barge unloading facilities, water intake and discharge structures or a solid waste landfill within the 100-year floodplain requires a Floodplain Construction Permit.

The applicant needs to perform hydraulic analysis to determine pre-construction and post-construction affects upon the floodway and floodplain. The applicant must demonstrate that the proposed construction will not impede the floodway or affect floodplain capacity to the extent that floodwaters are backed up or diverted to cause flooding in other areas. In order to perform this demonstration, the applicant will need to work with the local floodplain coordinator (usually county or city based) as well as the state DOW. The applicant may need to develop surveyed stream cross-sections and hydraulic models based upon data available from the DOW, USACE and the Federal Emergency Management Agency (FEMA) flood insurance program or generate and support their own data.

8.4.3.1 Influence on Plant Siting, Design and Operation

In general, development of any structures within the regulatory floodplain should be avoided. Preconstruction site planning should include a thorough review of floodplain boundaries identified on available FEMA Flood Insurance Rate Maps (FIRMs). It is also important to note how current is the available floodplain information and whether the documented floodplain may be revised to reflect more accurate and current site information. Since substantial amounts of water are required for a CTL facility, it may not be possible to entirely avoid a floodplain. In that case, it will be necessary to work through the permitting process.

In addition to obtaining a floodplain construction permit, the applicant will also need to design facility structures and equipment to be above the base flood elevation or work with FEMA to flood proof any structures constructed in the floodplain. This can be accomplished in a variety of ways, but this will influence the design of the plant facilities.[11]

- Impacted facilities within the floodplain may be constructed on areas built up with fill materials to artificially raise the ground surface above the 100-year flood water surface elevation. Additionally, a floodwall may be constructed around the facility to prevent flooding. Fill structures located in the floodplain and floodwalls will require additional permitting and approval through the U.S. Army Corps of Engineers and the state.

- Facilities below the 100-year water surface elevation can be designed with flood proofing techniques to prevent flood water from entering buildings or interacting with equipment. Wet flood proofing can be implemented to allow floodwaters to pass through the structure without causing substantial damage. Any

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[11] Non-Residential Floodproofing – Requirements and Certification for Buildings located in Special Flood Hazard Areas in accordance with the National Flood Insurance Program. Federal Emergency Management Agency, Federal Insurance Administration, Technical Bulletin 3-93, April 1993.

infrastructure or equipment inside wet flood proofed buildings must be designed and constructed to avoid damage from floodwaters.

8.4.4 Water Quality Certification

Projects involving construction, dredging or discharge of materials into waters of the U.S. (including wetlands) require permits through the USACE under Section 404 of the CWA and a floodplain construction permit as described above. Section 401 of the CWA specifies that any applicant for a federal permit that will involve discharge of pollutants to certain U.S. waters must obtain a certification from the state or regional authority that the activity will not adversely impact water quality. The applicant must supply the certification to obtain the federal permit. In Kentucky, the applicant must obtain the "Section 401 Water Quality Certification" from the DOW and meet any additional conditions that may be imposed to assure that water quality standards contained in Chapter 5, Title 401 of the Kentucky Administrative Register are maintained. Kentucky program requirements are contained in 401 KAR Chapter [9].

The process is coordinated with USACE permitting and conducted simultaneously with the Kentucky floodplain construction permit. It involves completing a "Combined Application for Permit to Construct Across or Along a Stream and/or Water Quality Certification". Typically the applicant must demonstrate that they will incorporate best management practices to control erosion and introduction of sediment or other pollutants into the waters of Kentucky. If wetlands are involved, the applicant will need to work with the USACE and DOW to demonstrate alternatives that emphasized avoidance of wetland impact and appropriate mitigation for any impact to wetlands. General conditions that apply to water quality certifications are:

- Measures shall be taken to prevent or control spills of fuels, lubricants or other toxic materials used in construction from entering the watercourse.
- All dredged material shall be removed to an upland location and/or graded on adjacent areas (so long as such areas are not regulated wetlands) to obtain

original streamside elevation and prevent artificial obstruction of overbank flooding.

- In areas not riprapped or otherwise stabilized, revegetation of stream banks and riparian zones shall occur concurrently with project progression. At a minimum, revegetation will approximate conditions prior to the disturbance.
- To the maximum extent practicable, all in-stream work under this certification shall be performed during low flow.
- Heavy equipment such as bulldozers, backhoes and draglines should not be used or operated within the stream channel. In cases where in-stream work is unavoidable, it should be performed in a manner and duration that minimizes resuspension of sediments and disturbance to substrates and bank or riparian vegetation.
- Fill or riprap, including refuse fill, shall be of such composition that it will not adversely affect the biological, chemical or physical properties of the receiving waters and/or cause violations of water quality standards. Riprap should be of a size and weight that will not cause bank stress or slump conditions.
- If water supply intakes located downstream may be affected by increased turbidity and suspended solids, the permittee shall notify the operator when work will be done.
- Removal of existing riparian vegetation should be restricted to the minimum necessary for project construction.
- Evidence of stream pollution or jurisdictional wetland impairment and/or violations of water quality standards occurring as a result of the activity (either from a spill or other forms of water pollution) should be reported immediately to the Kentucky Division of Water at 502-564-3410.

8.4.4.1 Influence on Plant Siting, Design and Operation

Similar to the floodplain construction and USACE permit requirements, it is best to design, build and operate a CTL facility at a location that does not involve construction or discharge in any water body. However, due to process and cooling water requirements as well as access to fuel markets, this may not be practical or feasible. Therefore, minimizing any impact should be a primary consideration along with developing appropriate mitigation measures for any unavoidable impacts.

8.4.5 Water Withdrawal Permit

A CTL facility will require a substantial water supply ranging from 1500 – 2500 gpm (> 2 MGD). Typically this will be obtained from a river or lake, but may also be supplied by groundwater wells. Therefore, it is essential to locate a water supply with sufficient capacity to provide this amount of water without substantially diminishing the supply for other current and future users. Water withdrawals greater than 10,000 gallons per day from any surface, spring or groundwater source are regulated under KRS §151.140-150 and 401 KAR 4:010. Water withdrawals required for use in a steam-powered electrical generating plant with retail power rates regulated by the Public Service Commission are subject to separate PSC requirements.

A standard permit must be obtained from the DOW to authorize the withdrawal and use of water in excess of the regulatory threshold. Applications should be made 3 – 6 months prior to start-up. The DOW will determine if the source of water has sufficient capacity for the anticipated withdrawal amounts. If approved, the facility will need to notify the agency when operations begin and report actual water withdrawal amounts on a monthly basis.

8.4.5.1 Influence on Plant Siting, Design and Operation

A CTL facility will require a substantial water supply and will therefore need to be located near a sizeable source of water, such as a river or lake. The facility will need to confirm water supply requirements, determine how much water can be feasibly recycled and what make-up supply will be needed. Prior to siting, the facility will also need to confirm that the anticipated water supply has sufficient capacity to supply the facility without diminishing capacity for existing users of the source. After siting, the facility will need to obtain a permit to withdraw the required amount of water and report water consumed to the state.

8.4.6 Potable Water

Potable water for on-site use may be provided by installing a drinking water treatment system or it may be provided by a local municipal supply.

If the CTL facility plans to construct and operate a water treatment and distribution system for drinking water supply that serves at least 25 individuals daily (public water system, 40 CFR 141), then the facility will need to comply with the public water system requirements contained in 401 KAR, Chapter 8. These include: submitting design plans and obtaining approval for the system prior to construction; operating and maintaining the system by a certified operator; monitoring the system to insure drinking water standards are maintained; providing monthly monitoring reports to the DOW; notifying users and the state when standards are not met; and taking appropriate action to correct any noncompliance with applicable drinking water standards.

If a municipal potable water system is located nearby, then the CTL facility will need to evaluate the feasibility of obtaining potable water from an outside source. This will require confirmation of facility needs and confirming utility capacity. It will also require an assessment of the costs required for connection to the utility, which will be dependent upon proximity and access. It may entail obtaining property easements or right-of-ways, which can delay the process.

8.4.6.1 Influence on Plant Siting, Design and Operation

Potable water supply may be provided from on-site sources or an off-site municipal or regional source. If off site, the CTL facility will need to confirm whether there is an off-site source with adequate capacity to meet the facility needs that is close enough to feasibly supply the potable supply. The cost and time required to obtain this connection will be dependent upon the proximity of the main line for the potable water supply. Following connection, operation and maintenance costs will be limited to monthly water use charges.

If an off-site supply is not nearby or feasible, the facility will need to design and operate an appropriate a water treatment facility on site. The facility will need to locate a source of raw water (likely the same as process water) and design an appropriate water treatment system. Prior to construction and operation, a permit will need to be obtained from the Kentucky Division of Water. After obtaining the permit and constructing the treatment plant, a state certified operator will be required to maintain the plant. Periodic water testing and reporting will also be required to ensure the plant is providing a safe drinking water supply. Prompt corrective action will be required if testing indicates that applicable standards are not being met.

8.4.7 Kentucky Pollution Discharge Elimination System (KPDES)

Consistent with the requirements of the CWA, associated federal regulations and the authority granted by EPA, the Kentucky Pollutant Discharge Elimination System (KPDES) applies to any discharge of a pollutant from a point source into the waters of Kentucky. KPDES requirements are found at 401 KAR, Chapters 5 and 10. The DOW manages this program and issues permits for several types of point source discharges that may occur at a CTL facility. These include stormwater discharges associated with construction activities or in contact with industrial activities; process wastewater discharges; and sanitary wastewater discharges.

8.4.7.1 Construction Activity Stormwater Discharges

Construction activities that disturb one or more acres require a permit to discharge any pollutant (including sediment) into Kentucky waters. For most construction activities, the applicant will need to complete and submit a “Notice of Intent for Storm Water Construction Activities” (NOI-SWCA) prior to construction (at least 7 days electronically or 30 days by mail) to receive authorization under the state general permit general stormwater permit. The applicant will need to identify the location of the project, extent of surface disturbance, receiving water body(ies), anticipated start and end of construction.

Under the terms of the permit, the applicant will need to implement best management practices to control stormwater runoff and erosion. They will also need to develop and implement a Stormwater Pollution Prevention Plan to ensure that management practices are implemented and effective. General management practices contained in the permit include:

- A requirement to minimize disturbance;
- A requirement to maintain a 25 – 50 feet buffer between the edge of the receiving waters and any disturbance for all projects; and
- A requirement to conduct immediate stabilization practices in critical areas near receiving waters for all projects;
- A requirement to initiate final stabilization practices within 14 days after construction has ceased.

It should be noted that this general permit does not apply to construction activities that will discharge to waters categorized as outstanding national or state resources, cold water aquatic habitat or impaired under 401 KAR Chapter 10. Any construction activity located near these types of waters will require an individual KPDES permit and undergo the longer and arduous individual permit process, which may take as much as 6 – 12 months to complete.

8.4.7.1.1 Influence on Plant Siting, Design and Operation

Prior to disturbing land for construction of a CTL facility, a stormwater permit authorizing the construction activities will be required. In general, stormwater permits for construction activities can be obtained relatively easily with a preconstruction notice (7 –

30 days prior to construction). During construction, best management practices will need to be used to minimize erosion, control runoff and avoid impact to nearby streams. These practices will need to be documented in a Stormwater Pollution Prevention Plan that will require periodic inspections to ensure practices are maintained. Following completion of construction the facility will need to file a notice of termination to cancel the permit.

One exception to this general scenario is if the construction will affect outstanding national or state resources, cold water aquatic habitat or impaired waters identified in 401 KAR Chapter 10. Any construction activity located near these types of waters will require an individual KPDES permit and undergo the longer and arduous individual permit process, which may take as much as 6 – 12 months to complete. Therefore, it would be prudent during the site evaluation phase to determine if any of these categories of waters will be impacted and design the facility to avoid their impact, where possible.

8.4.7.2 Process Wastewater and Stormwater Discharges

Wastewater generated during the operation of a CTL facility that will be discharged directly to a Kentucky water body will require a separate KPDES permit. This presumes that the volume of wastewater that is not recycled and reused from gasification, CTL and cooling processes cannot be feasibly sent to an off-site municipal or regional treatment facility. Applications must be completed and submitted to the DOW 6 – 12 months prior to construction of the facility. The applicant will need to provide a complete: description of all processes generating wastewaters; description of wastewater treatment methods; and list of all pollutants and their respective concentrations in each wastewater stream. The applicant will also need to identify the volume of wastewater at each discharge and the water bodies that will receive the wastewater discharges. A base fee of $7000 (for discharges exceeding 50,000 gpd) is required for review of the application and issuance of the permit. Additional fees may be incurred if the permit is contested.

Permit limits are developed to maintain regulated water quality standards in the receiving water body as well as other specific process or industry standards. Larger receiving water bodies generally have greater capacity to meet water quality standards for wastewater discharges; however, permit limits are based on the designated use and existing water quality or category of the receiving water body. Kentucky has six designated water uses identified in 401 KAR 10:026: *warm water aquatic habitat; cold water aquatic habitat; primary contact recreation; secondary contact recreation; domestic water supply; and outstanding resource water*. Water quality standards begin with basic in stream requirements that become stricter as the designated use changes from warm water aquatic habitat to outstanding resource water. Additionally, Kentucky's antidegradation regulation (401 KAR 10:030) establishes four categories of waters: *impaired, high quality, exceptional and outstanding*. The goals of the program are to ensure that existing water quality is maintained, additional water pollution is prevented and polluted or impaired waters are abated. To meet these goals, pollutant discharge limits will generally be stricter for outstanding waters and impaired waters.

Additional standards that could apply to a CTL facility are defined in Sections 316 (a) and (b) of the CWA and imposed as part of the KPDES permit process. Due to the large amount of water required for cooling at power plants, Section 316 addresses concerns for potential impact to fish and wildlife at the discharge and intake from these systems. Elevated discharge temperatures from cooling systems can adversely affect the growth rate, feeding habits and habitat preference of fish, shellfish and other aquatic life. Section 316(a) addresses these potential impacts by requiring that the permit applicant design the facility to ensure that the discharge does not elevate receiving water body temperatures above applicable water quality standards or levels acceptable for the designated water use.

On the intake side, small aquatic organisms can be adversely impacted by being carried in through the intake structure and harmed, a phenomenon known as entrainment. Alternatively, when screens are installed on the intake to avoid entrainment, larger species may become trapped against screens on the intake. Section 316(b) controls these impacts by imposing technology-based and performance design standards that minimize impingement and entrapment of local fauna on or in the intake structure. These generally affect screen design and require a low velocity intake. They also impose requirements to minimize cooling water use by requiring best available technology and avoiding once-through cooling processes.

8.4.7.2.1 Influence on Plant Siting, Design and Operation

During facility siting, it is therefore important to confirm the water use designation and category of potential water bodies that may receive wastewater discharges from the facility – both stormwater and process wastewater. Where possible, facilities should be located near relatively large water bodies and avoid discharges to impaired or outstanding waters and those designated for recreational use or as a water supply.

The specific designated use and water quality category of the receiving water body will dictate appropriate wastewater treatment design to achieve permit allowed pollutant loading to the receiving water body. Additional design considerations will need to be made to insure that process and cooling tower discharge temperatures meet applicable temperature limits required by Section 316(a) of the CWA and the intake structure meets applicable Section 316(b) requirements. Process design and operation of the cooling system will also need to meet Section 316(b) requirements.

On-going operations will need to be maintained to meet permit requirements, including water discharge quality as well as appropriate management practices and plans designed to minimize excess pollutant loading and immediately respond to any emergencies that may cause a water quality problem.

8.4.7.3 Sanitary Wastewater Discharges

In addition to process wastewaters, any CTL facility will have sanitary wastewater that will need to be managed by either treating on site or by an off-site municipal or regional treatment facility. If on site, the facility will need to incorporate the treated discharge into their KPDES permit. They will also need to have a certified wastewater treatment operator (KRS 224.73-110) to supervise the operation and maintenance of the treatment plant in accordance with permit requirements.

If a municipal wastewater treatment system is located nearby that has the capacity to accept sanitary sewage from the CTL facility, then the sewage may be direct to the municipal treatment facility. It is likely that the CTL facility will need to install or pay for the installation of connecting lines and obtain authorization for the connection. The cost for this connection will be dependent upon the proximity of the municipal treatment facility sewer line. In the event that the wastewater stream may also include process wastewaters, a separate municipal pretreatment permit will be required. The facility will also be required to develop emergency response and best management plans to prevent upsetting the municipal treatment facility.

8.4.7.3.1 Influence on Plant Siting, Design and Operation

Location of the CTL facility near a municipal or regional wastewater treatment facility will provide the option of directing facility sanitary sewage to an off-site treatment facility. The facility will likely need to install and/or pay for the installation of connecting lines and obtain authorization for the connection. The cost for this connection will be dependent upon the proximity of the municipal treatment facility sewer line.

If this is not possible or feasible, the facility will need to design and operate an appropriate treatment facility on site. This will need to be incorporated into the facility’s KPDES permit and require a certified operator. It will also require long term operation and maintenance costs.

8.5 Electric Service, Generation and Transmission

A CTL facility will need a substantial external power supply for start-up. After start-up, the facility will likely generate its own power and may create excess power that can be sold to the grid. The process of obtaining the appropriate approvals will require coordination with the local utility provider for service and may require coordination with federal, state and regional authorities responsible for regulating and operating electric generation and transmission systems.

In Kentucky, there are:

- 24 companies that solely provide electric distribution service;
- 3 companies that provide electric generation and transmission service (Big Rivers Electric Cooperative – BREC, East Kentucky Power Cooperative – EKPC, and the Tennessee Valley Authority – TVA); and
- 3 companies that provide generation, transmission and distribution service (American Electric Power – AEP/Kentucky Power-KP, Duke Energy and E.ON U.S., including Kentucky Utilities- KU and Louisville Gas & Electric-LG&E).

Depending upon the type of service required, a CTL facility may need to interact with one or several of these electric companies.

8.5.1 Electric Service

Coordination with the local electric utility is required to initiate planning and feasibility studies to ensure adequate power is available for startup and determine a pathway to upload excess power. This process typically begins with a review of project power requirements and determining what utilities provide service for the project area. The utility will require the facility to enter into a formal agreement to evaluate the feasibility and ability of the utility to supply the power demand. After completing the agreement, the utility will perform an engineering study.

A typical engineering study for local electric supply will cost around $10,000 and take 60 days to complete. The cost of the engineering study may be incorporated into future utility bills if the project is completed. Timeframes and cost-sharing arrangements for any upgrade required for connection and to ensure sufficient power capacity will be provided in the study.

Schedules and costs vary widely depending upon whether additional right-of-way must be obtained, additional transmission lines and substations must be installed and if additional power capacity is needed by the utility. For planning purposes, the process of negotiating an agreement with the local utility, completing the engineering study and arranging for electrical service may take 3 – 6 months, excluding design and construction of any system upgrades including substations or new transmission lines.

The local utility study should be coordinated with any interconnection study required for selling power to the grid.

8.5.2 Generation and Transmission

If a CTL facility plans to generate excess electricity and sell it wholesale to the electric transmission grid, there must be capacity in the transmission system. Depending upon where it is located in Kentucky and how it plans to connect to the transmission system, the facility will need to obtain approval from the appropriate Regional Transmission Organization (RTO), Independent Transmission Organization (ITO) or local generation/transmission company.

A developer using AEP or EKPC electrical lines will work with PJM Interconnection to address the transmission of excess power from the facility. PJM Interconnection is a Regional Transmission Organization (RTO). If E.ON U.S. electrical lines will be used, the facility will work with South West Power Pool (SWPP). SWPP is an Independent

Transmission Organization (ITO) under private contract with KU. If the project will use TVA or Duke transmission lines, the developer will work directly with these entities. If the facility is located in the service territory of any of the remaining 24 distribution companies, the facility will have to work with the local distribution company and the associated generation/transmission company (e.g., BREC, EKPC, or TVA).

To initiate the interconnection planning process, the developer contacts the appropriate RTO to review points of connection and enter into a formal agreement for the RTO to evaluate the feasibility and impact of the proposed connection. The scope of the study will be driven by the projected level of power that will be provided to the transmission system. If less than 20 megawatts (MW) will be sold on the open market, only certain portions of the RTO interconnection study may be performed. Typically, an interconnection study consists of: a feasibility study phase, a system impact phase, and a facility design study phase. Each phase requires a deposit and fee to be paid by the project developer. The entire process can take approximately one year, excluding any infrastructure construction or improvement.

8.5.3 Influence on Plant Siting, Design and Operation

It is important for the project developer to determine the appropriate utility and RTO/ITO that they will need to work with based upon the location of the project. Although all have similar requirements, project schedules, fees and needs for infrastructure changes will vary. Importantly, PJM accepts applications only ***twice a year***, making timing of the submittal important. PJM membership is not required for the initial planning and construction phases, but is required prior to commercial operation. Membership entails certain data requirements, operational and market coordination, committee support and financial obligations including initial and annual fees.

Unlike PJM, SPP does not charge a membership fee for interconnection to the power system. Additionally, SPP accepts application requests on an on-going basis, rather than only twice a year. Similarly, applications to the non-RTO generation/transmission entities and local utilities do not typically have a restriction on when applications will be received and reviewed.

8.5.4 Kentucky Siting Board

Any CTL facility that plans to generate excess power and connect to the transmission grid to sell the excess in the wholesale market (i.e., rates not subject to the Kentucky Public Service Commission (PSC)) is considered a Merchant power plant. Requirements for approval of merchant power plants are found in KRS 278.700 – 716. Merchant power plants with a generating capacity of 10 megawatts or more and transmission lines capable of carrying 69kV or more that are less than 1 mile in length must prepare applications for construction to the Kentucky State Board on Electric Generation and Transmission Siting (Siting Board). The seven-member Siting Board within the PSC reviews these applications and decides whether to approve or deny them. 807 KAR 5:100 establishes the application fees which are a function of the length of the line and the amount of capacity it will carry or the nameplate generating capacity. The fee may be as much as $200,000.

Construction of a transmission line greater than 1 mile in length and carrying more than 138kV would be directly subject to PSC jurisdiction (807 KAR 5:120 (2005)). In that case, the developer would need to coordinate with, and support the local electric utility in the request for approval of the extension of transmission lines from the PSC.

When working with the Siting Board, the process begins by submitting a **Notice of Intent (NOI)** at least ***30 days prior to submitting the application*** (but no more than 6 months). The NOI is made public and must include: the identity of the applicant; a brief description of the proposed facility and its location; the address of the local planning and zoning commission, if any; and a description of equipment setbacks (distance from property line). The 30 day period is used by the Siting Board to appoint ad hoc members and hire any consultants it may need for the application review.

A Public Notice of the intent to file an application must be sent to all adjoining property owners, county officials and other interested parties at least ***30 days prior to filing the Application.*** The Public Notice may be filed with the NOI or subsequently.

Following the Public Notice, the complete application must be submitted to the Siting Board. The application must contain the following information:

- A complete description of the project sponsor, proposed operations and location of the project with information regarding proximity to residential neighborhoods, schools, hospitals, nursing homes and parks.
- Evidence that adequate public notice of the project has been made to adjacent landowners and the public.
- Evidence of the applicant's public involvement activities.
- An environmental assessment report that includes a discussion of potential impacts and methods used to control impacts from air emissions, wastewater discharges, waste management activities and water consumption. The applicant must also address visual impacts, noise, traffic and affect upon property values.
- A statement of compliance with any local zoning regulations and noise control ordinances.
- An analysis of the effects of the proposed facility on the electric transmission grid.
- An analysis of the economic impacts upon the community.
- The applicant must also disclose any previous history of environmental violations.

Upon receipt and initial review, the Board will inform the applicant whether the application is administratively complete or whether additional information may be required. Technical review will be initiated.

According to the Board Proceedings regulations found at 807 KAR 5:110, an interested party may request a Public Hearing or initiate an Evidentiary Hearing ***within 30 days of application submittal.*** If a hearing is scheduled, the applicant will be required to Public Notice the hearing date, which typically occurs within 60 days of application submittal.

The Board must make a decision ***within 90 days of receipt of an administratively complete application*** (if there is no hearing) or ***120 days if a hearing occurs***. By majority vote, the Board shall grant or deny a construction certificate, either in whole or in part, based upon the criteria contained at KRS 278.710. These criteria include:

- Impact of the facility on scenic surroundings, property values, adjacent property land use and surrounding roads;
- Anticipated noise levels from construction and operation;
- Regional and state economic impact of the facility;
- Whether the project is located on an existing electric generating site;
- Whether the facility meets local planning and zoning requirements;
- Whether the additional electric load of the generating plant will adversely affect reliability of service to retail customers;
- Whether the structures (i.e., stacks) meet applicable local and state setback requirements;
- The efficacy of proposed measures to mitigate any of the above impacts;
- Environmental compliance history.

8.5.4.1 Influence on Plant Siting, Design and Operation

Application to the Siting Board for a construction certificate to build a Merchant Generating Facility or Transmission Line is a formal process to consider potential local concerns and impacts that may not be directly addressed through applicable federal or state environmental permitting programs. It is an opportunity for the applicant to identify and minimize potential local concerns regarding aesthetics, land use, noise, traffic and other environmental impacts by involving the community at an early stage in the planning process.

With respect to how the process can influence project siting, design and operation, the applicant will need to consider the following general criteria and establish the facility to minimize impacts to the local community and environment.

- Locate the facility on property with a minimum buffer area of at least 1000 feet from the operation to any adjoining property owner and 2000 feet from any residential neighborhood, school, hospital, nursing home or park.
- Confirm local zoning requirements and if zoning changes may be required, plan for sufficient time to address any local concerns and achieve the zoning change (minimum 1 year prior to site development).
- Ensure that public involvement activities are included during the planning and zoning process.
- Follow the Siting Board NOI and application process and ensure all required information is provided and adequate public notices are completed.
- If connecting to the grid, the facility will need to have at least an initial feasibility study completed to confirm that any connection will not adversely impact the grid and can be accomplished in feasible manner.
- Design and operate the facility to minimize impacts to air, water, noise, aesthetics, nearby properties and traffic. Depending upon the location and type of operations planned, the facility may need to be designed to meet more stringent requirements than would be required for federal or state environmental permits.

9.0 REGULATORY AND PERMITTING TIME FRAMES - IMPACTS UPON THE ECONOMICS OF A PROJECT

Regulatory and permitting time frames and the ensuing uncertainty have an economic impact on the feasibility of any large project. First and foremost, uncertainty increases costs. From the developer’s perspective, regulatory or permitting uncertainty leads to increased cost of borrowing funds for construction of large projects, will lead to loss of equity investors, and will prevent project developers from being able to enter into favorable long term contracts for construction materials, such as steel. Regulatory or permitting delays can be responsible for stopping a project with high public and private benefits from going forward.

Even though permitting impacts all development, energy project development with its high capital cost is particularly impacted. All energy projects, whether fossil, nuclear or renewable, have been impacted to some degree by permitting delays. This was recognized in the Energy Policy Act of 2005, with Congress inserting provisions to coordinate the siting and permitting of large projects, especially interstate electricity transmission lines. Wind projects have been stopped or have faced serious delays in many states because of permitting issues, especially concerning migratory birds and bat populations.

A March 2011 report commissioned by the U.S. Chamber of Commerce in conjunction with its *Project No Project* initiative summarizes the status of over 351 proposed energy projects that have been delayed or cancelled due to "significant impediments, such as regulatory barriers, including inefficient review processes and the attendant lawsuits and threats of legal action."[12] Bill Kovacs, Senior Vice President for Environment, Technology and Regulatory Affairs at the U.S. Chamber of Commerce, states that "the Chamber believes our nation’s complex, disorganized regulatory process for siting and permitting new facilities and its frequent manipulation by NIMBY (not in my back yard) activists constitute a major impediment to economic development and job creation.......Serious regulatory inefficiencies and permitting delays persist and NIMBY activists are winning more often than they are losing. All of this is leading to serious marketplace uncertainties, which can drive investors to opt not to finance new major construction projects or pull out of previous financial commitments."[12] The report notes that nearly 45 percent of the identified projects are renewable energy projects. Results of the assessment are available on web project inventory, the *Project No Project* Website.[13]

9.1 Permitting Delays for Fossil Fuel Projects

There are particular issues when siting a project utilizing fossil fuel resources, including natural gas, but coal has faced increasingly difficult siting and permitting challenges in recent years. When permitting a project which uses coal as a feedstock, whether that is a power plant to generate electricity, a facility to produce alternative liquid transportation fuels from coal, a coal-to-substitute natural gas plant, or a facility that uses coal as a feedstock to make chemicals -- the economics of the project will be strongly impacted by delays that result from permitting requirements. This has not escaped the notice of groups who are determined to stop any and all coal facilities. Many national environmental organizations have well organized and funded efforts (see Sierra Club and the Beyond Coal Campaign) to file against any facility using coal, including for example, a map and database of all projects, the regulatory agencies responsible for permits, and the status of their “stopping the coal rush” initiative[14].

Permitting and regulatory impacts for CTL facilities are difficult to quantify due to the lack of facilities in operation in the United States. It is clear, however, that permitting and regulatory considerations will have substantial impact on the projects' feasibility, costs and schedules. Evaluation of permitting by the Coal To Liquids And Gas Subgroup of the Technology Task Group of the National Petroleum Council Committee

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[12] U.S. Chamber of Commerce. "An Introduction to Project No Project." Bill Kovacs. March 10, 2011. http://www.uschamber.com/sites/default/files/reports/PNP_EconomicStudyweb.pdf

[13] http:www.projectnoproject.com

[14] See: “Stopping the Coal Rush” *Sierra Cub*. http://www.sierraclub.org/environmentallaw/coal/plantlist.asp. June 25, 2010

On Global Oil And Gas was performed in 2007. The subgroup report states that "No commercial-scale CTL plant has been sited or permitted in the United States. Given that these plants will have aspects of both a refinery and a power generation facility, it is not clear how quickly this untested permitting process can be expedited, particularly if activist groups are aggressively intervening. These potential delays have associated financial risks to the first plants." Furthermore, the Subgroup concluded that "The process of siting and permitting large facilities is a major barrier to investment, particularly in the developed nations. Any project with coal as a feedstock can expect environmental challenges, both by the public and in court. A world-scale CTL facility site will encompass roughly a square mile of land. Not only will the raw size of this type of facility draw regulatory attention, the fact that this is a new industry with very few precedents to cite will make permitting a major obstacle that consumes a substantial amount of resources."[15] Three years later, the Associated Press reported that "No coal-to-liquids plants have been built in the United States."[16]

Seven CTL projects identified on the *Project No Project* website have experienced delay due to regulatory impediments. To provide a perspective of the impacts to costs and schedules, the project summaries are provided below[13]:

- **American Lignite Energy LLC, Coal-to-Liquids project, ND**
  STATUS: In progress
  OPPOSITION: Sierra Club, Dakota Resource Council
  PROSPECTS: Indeterminate
  BACKGROUND: American Lignite Energy, LLC was formed in late 2006 to develop a coal-to-liquids project at an undefined site in western North Dakota at a projected cost of approximately $4 billion. The proposal reportedly would create up to 3000 construction and 700 permanent jobs. Plans for the project were put on hold in January 2009 due to regulatory uncertainty. In January 2010, the developers announced they would evaluate next steps after the election of a new Congress.

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[15] Coal To Liquids And Gas Subgroup of the Technology Task Group of the National Petroleum Council Committee On Global Oil And Gas. Topic Paper #18 Coal To Liquids And Gas. July 18, 2007.

[16] Associated Press as reported by FoxNews.com. "Montana tribe: $7B coal-to-liquids plant needs more federal support or investors will shy away." August 25, 2010.

Sierra Club appears to oppose the project in keeping with its national strategy of opposing all coal projects for any reason or no reason.

- **Medicine Bow Project, Carbon County, WY**
  STATUS: In progress, with opposition
  OPPOSITION: Sierra Club
  PROSPECTS: Indeterminate
  BACKGROUND: In 2006, the developer proposed construction of a $2 billion coal to liquid facility to produce up to 21,000 barrels per day of gasoline and other products in Carbon County, Wyoming. The project will use a proprietary ExxonMobil technology and is estimated to create up to 6000 jobs, including 450 full-time jobs, and provide gasoline at a competitive price (e.g. $60 per barrel).

  A siting permit was granted in December 2007. An air emissions permit was granted in March 2009. Sierra Club appealed, claiming the air permit failed to properly address sulfur dioxide and particulate emissions and to treat the project as a "major source" of hazardous air pollutants, among other things. In February 2010, the Wyoming Environmental Quality Council dismissed the appeal, and Sierra Club appealed to the Wyoming Supreme Court. Oral argument occurred in October and a decision is pending.

  The developers have applied for a $2 billion Department of Energy (DOE) loan guarantee. Sierra Club and other environmental special interest groups oppose the application as part of their campaign against all coal plants. DOE has indicated it might rule on the application sometime in early 2011, although it has yet to complete an environmental impact statement on the project. Construction has yet to begin.

- **Baard Energy, Coal-to-Liquids plant, OH**
  STATUS: In progress, with opposition
  OPPOSITION: Sierra Club, Natural Resource Defense Council
  PROSPECTS: Indeterminate
  BACKGROUND: Baard Energy plans to develop a coal-to-liquids plant in Wellsville, Ohio at an estimated cost of $6 billion. The facility is designed to capture and ultimately sequester at least 85% of all carbon dioxide produced, and will produce synthetic jet fuel, diesel fuel and other feedstock. It is estimated that 2,500 jobs would be created during the peak construction period, plus 200 full-time jobs at the plant and about 750 coal-mining jobs. The plant will cover approximately 600 acres.

Project opponents have filed three separate legal actions to stop the project. In August 2008, Ohio EPA issued a final National Pollution Discharge Elimination System (NPDES) permit. In September Sierra Club and NRDC appealed to Ohio's Environmental Review Appeals Commission claiming Ohio EPA failed to set sufficiently stringent discharge limits for numerous pollutants, unlawfully exempted coal pile runoff discharges from permit limits for three years, and added new sections to the final permit that were not included in the draft permit. This appeal is pending.

In November 2008, Ohio EPA issued the final permit-to-install/PSD permit for the facility. In December Sierra Club and NRDC appealed to the Ohio Environmental Review Appeals Commission claiming the permit was deficient because Ohio EPA failed to include any analysis or control of carbon dioxide emissions from the plant, to accurately analyze or impose emission limits for hazardous air pollutants and to analyze impacts to the State's general air quality from the proposed plant. In October 2009, Ohio EPA issued a modified version of the appealed PTI/air permit to include case-by-case Maximum Achievable Control Technology (MACT) limits to control the emission of hazardous air pollutants. This appeal is pending and a hearing is scheduled for February 2011.
In January 2009, Sierra Club and the Natural Resources Defense Council (NRDC) filed a federal lawsuit challenging a wetlands fill permit issued by the U.S. Army Corps of Engineers under the National Environmental Policy Act and the Clean Water Act. The suit alleged the agency neglected some of the plants most significant environmental impacts, including air pollutants and carbon dioxide impact on human health and welfare, and failed to accurately balance the project's harms against the alleged benefits. The U.S. District Court ruled against the opponents in March 2010, and they appealed to the U.S. Sixth Circuit Court of Appeal. This appeal is pending.

Additionally, NRDC filed a Freedom of Information Action against DOE seeking financial information to use against the project developer.

Although the opponents have yet to prevail in any of their litigation efforts, the delay caused by their actions appears to be having a significant economic impact on the project. For example, the litigation caused the developer to abandon its effort to secure a U.S. Department of Energy loan guarantee for the project, DOE stated that the lawsuits would be part of the "risk evaluation" and could affect financing costs and timeliness, meaning pending lawsuits would have to be settled before the company could obtain loan guarantee funds. Reports suggest the litigation delay is causing the developer substantial cash flow problems, although it appears that funding has been secured to complete the land purchase. Construction is planned to commence in 2011.

- **The Fairbanks Economic Development Corporation Coal-to-Liquids Plant, AK**
  STATUS: In progress with opposition
  OPPOSITION: Environmental: Sierra Club
  PROSPECTS: Indeterminate
  BACKGROUND: The proposed $2-6 billion plant would produce 20,000-40,000 barrels of liquid fuel per day from both coal and biomass. The plant would provide a solution to high energy costs in Fairbanks as well as manufacture jet fuel. In May, 2008, Fairbanks Economic Development Corp. (FEDC) signed a contract with Toronto-based engineering firm Hatch Ltd. to conduct a $550,000 screening study on a potential coal-to-liquids (CTL) plant in Fairbanks, Alaska. Also, FEDC has been working with the US Air Force with respect to plant development. The proposed plant would use the Fischer-Tropsch chemical conversion process – a process that converts coal and natural gas to liquid fuels. The facility would generate 60-200 megawatts of power and produce jet fuel, diesel and home heating oil. The coal-to-liquids plant could potentially supply fuel at a cost of approximately $2 per gallon about the same price customers pay when oil is going at $88 per barrel. The plant is opposed by environmental groups due to alleged "greenhouse gas emissions" concerns.

- **Alaska Natural Resources-to-Liquids LLC**
  STATUS: In progress with opposition
  OPPOSITION: Sierra Club; Cook Inletkeeper
  PROSPECTS: Indeterminate
  BACKGROUND: The Alaska Natural Resources-to-Liquids LLC project is estimated to cost $5 billion. The project would consist of a 300 mega-watt coal-to-liquids (CTL) plant near the Beluga coal fields using the Fischer-Tropsch chemical conversion process. ANRTL's project would manufacture 80,000 barrels per day of ultra-clean diesel and naphtha for U.S. West Coast markets. In the longer term, the plant could make a variety of other products, like jet fuel.
  The proposed location seems well-suited for the proposed plant. The Beluga CTL plant and coal reserves next to the tide water, and the estimate is the Beluga coal field has 50+ years of supply. The plan is for CO2 sequestering through local depleted gas fields, and CO2 enhanced oil recovery in local reservoirs if up to 150 to 300 million barrels. The site is 12 miles from the electric grid serving 85% of Alaska's electric load, and 10 miles from the natural gas transmission system delivering 500 mmcf/d. Almost half of Alaska's population

lives within 65 miles of the CTL site, and 80% of the engineering, design, fabrication, construction and operating companies serving Alaska's North Slope and Cook Inlet oil and gas industry are located within 45 miles of this location.

- **Gilberton Coal-to Clean Fuels and Power Project, PA**
  STATUS: Canceled
  OPPOSITION: Sierra Club, Local officials, Local citizens
  PROSPECTS: Indeterminate
  BACKGROUND: The developer planned a 41 megawatt coal-to-oil plant to convert anthracite waste coal into fuel, producing 5,000 barrels of diesel fuel a day. The project qualified for a substantial federal grant and had political support. A 2007 environmental impact statement was issued in preparation for disbursement of federal funds. However, the developer could not secure private financing and the project has not moved forward.

  Local citizen groups opposed development due to the potential CO2 emissions from the process. Sierra Club opposed the project as part of its national strategy to oppose all coal projects. It lists the project as a "victory" on its "Stopping the Coal Rush" website.

- **Malmstrom Air Force Base Coal-to-Liquids plant, Montana**
  STATUS: Canceled
  OPPOSITION: Sierra Club; Montana Environmental Information Center
  PROSPECTS: Unlikely
  BACKGROUND: On October 2007, the Air Force announced plans to build a coal-to-liquids plant at the Malmstrom Air Force Base in Great Falls, Montana. The project was endorsed and supported by the State and was expected to cost about $2 billion. Local environmental groups and Sierra Club opposed the project, the later in keeping with its national strategy to litigate against all coal projects. On January 29, 2009, the Air Force announced that it would no longer pursue development of the plant citing conflicts with Malmstrom's nuclear missile mission.

Additionally, an article about a proposed CTL plant in Montana indicates that a perceived anti-coal attitude is scaring off investors and delaying the project. "A federal tax credit for coal recently expired. Unless the political climate for coal improves, Black Eagle said, the tribe could be forced to suspend its project."[16]

Given the above examples, it is apparent that opposition to any coal-related project is nearly certain and may have devastating consequences: permit delays and appeals cause increases in direct costs and endanger financing because of perceived risk and uncertainty. The National Mining Association has urged the U.S. government to provide incentives to overcome these obstacles to CTL fuel facility development. "Coal refineries are expensive to construct, with capital costs in the $600-million-to-$700-million range for a 10,000 barrel per day plant, according to FT Solutions LLC. The technical and financial risks of a “first of a kind” plant in the United States have discouraged consideration of this type of investment in the past. Finally, the lead time for a coal refinery, as with all refineries, is a minimum of five to seven years under optimal circumstances."[17]

9.2 Coal Fired Power Plants and Electricity Supply

According to the National Energy Technology Laboratory (NETL), when discussing coal fired power plant additions, actual plant capacity additions have only been 12% of that announced from 2000 to 2009 and much of the delays and cancelations have been attributed to regulatory uncertainty or poor project economics due to increasing costs in the industry[18]. The economic downturn experienced in 2008 and 2009 has delayed the need for some of these plants, especially those producing electricity, but demand will recover and grow as the economy rebounds and needed capacity may not be in place to serve that increased demand. This would lead to brown-outs or black-outs in certain regions of the country.

Lack of affordable electricity will have a detrimental impact upon the economic development opportunities facing certain states and regions when growth recommences. According to the Energy Information Administration (EIA) and their projections in the 2010 Annual Energy Outlook, electricity use will increase over the period from 2008 to 2035 and this increase will be met by an increase in the use of

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[17] National Mining Association "Liquid Fuels from U.S. Coal- The technology is modern, proven and ready. It has national security, economic and environmental benefits. What is needed to make it happen?"

[18] “Tracking New Coal-Fired Power Plants”. http://www.netl.doe.gov/coal/refshelf/ncp.pdf .

natural gas, coal and renewable resources.[19] Coal will remain the dominate source of electricity generation, assuming plants are able to be built, and siting concerns are addressed.

However, if there is difficulty similar to what has been observed in the 2000-2009 period in power plant additions, the resulting lack of capacity will lead to loss of employment and the resulting economic growth and recovery. In a state like the Commonwealth of Kentucky, a lack of electricity capacity will have a negative impact in two major areas. Kentucky has a large manufacturing base, with 213,000 persons directly employed in the manufacturing sector in 2007, according to the Kentucky Cabinet for Economic Development[20]. Industrial electricity rates have been historically low in the Commonwealth due to an adequate supply of coal fired generation. Approximately 50% of the electricity consumed in Kentucky is consumed in the industrial sector, according to EIA's Electric Power Annual 2008[21]. Of that electricity generated in Kentucky in 2008, fossil fuels dominate as the fuel of choice. Therefore, coal fired power plants are an important part of the economy in Kentucky, and maintaining an adequate supply of power is crucial to economic recovery.

The second major area of impact of coal fueled power plants on Kentucky's economy stems from the fact that Kentucky is the third largest coal producing state in the United States, and of that coal that is mined more than 90% is used for the generation of electricity, either in the Commonwealth or in other states. Any decrease in the viability of coal resources for electricity generation will not only impact Kentucky as an industrial state, but also as a coal producing state. Delays in permitting can prevent adequate electricity supplies, impacting the productive sector of the Commonwealth, but delays in permitting across the country will have a negative impact upon the viability of the coal

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[19] Energy Information Administration 2010 Annual Report, Report #:DOE/EIA-0383(2010) http://www.eia.doe.gov/oiaf/aeo/overview.html#elecgen

[20] *Think Kentucky.* http://Thinkkentucky.com June 25, 2010.

[21] "Electric Power Annual 2008 – State Data Tables." *U.S. Energy Information Administration.* January 21, 2010. http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html June 25, 2010.

industry which is an important employer, and is a positive contributor to the tax base of the Commonwealth. In 2008, 18,906 employees were directly employed in the mining sector in Kentucky[22], and severance tax revenue to the Commonwealth totaled $270 million[23].

9.3 Coal Gasification

The gasification process can be used to generate a myriad of products. Coal has been used, and is used as a chemical feedstock, for example, the Eastman facility in Tennessee uses coal as a feedstock in processes resulting in everyday items. The gasification process is one that is versatile in both feedstock and final product. Utilizing steam and high pressures, the coal or other carbon based feedstock is broken down to its carbon monoxide and hydrogen as well as other gaseous compounds. Resulting impurities or pollutants can easily be removed and a resulting product can be produced including electricity, liquid transportation fuels, synthetic natural gas, chemicals and fertilizers.

The economic impact of coal gasification facilities to Kentucky would be positive in that it would be a new industry similar to the chemical industry, it would also be a new market for the coal resources of the Commonwealth. In fact, the Commonwealth recognized this in passage of the Incentives for Energy Independence Act (IEIA) in 2007[24]. Using a simple economic input-output impact model, and conservative assumptions regarding jobs, for a facility with a capital investment of $2 billion, with a construction period of two years, which produces synthetic natural gas and electricity, the economic impact is estimated to be $1.4 billion for the two year construction period,

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[22] "Coal Mining Productivity by State and Mine Type." *U.S. Energy Information Administration.* September 18, 2009. http://www.eia.doe.gov/cneaf/coal/page/acr/table21.html June 25, 2010.

[23] "Annual Coal Severance Tax Receipt Data." *Kentucky Coal.* January, 2009. http://www.kentuckycoal.com/documents/CoalEconomics/TaxData0708.pdf June 25, 2010.

[24] "Kentucky Economic Development Finance Authority (KEDFA) Incentives for Energy Independence Act." *Think Kentucky.* August, 2008. http://www.thinkkentucky.com/kyedc/pdfs/IEIA.pdf June 25, 2010.

with an approximate $40 million positive impact on tax revenues for the Commonwealth (these tax impacts would be reduced by the tax incentives granted under the IEIA, if applicable). Ongoing operation of this facility would result in an annual economic impact of $250 million, with an increase in tax revenues of approximately $50 million. Severance tax receipts from the 2.8 million tons of additional coal that would not otherwise have been sold, are estimated in excess of $5 million annual and the economic impact in the mining sector estimated to be approximately $150 million[25].

This economic impact if permitting delays result in the failure of such facilities to be sited in the Commonwealth will be a direct loss to Kentucky. Furthermore, it is likely that if these facilities are not located in regions with coal resources, they will not be located in the United States.

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[25] Modeling was done using IMPLAN, assuming: 50% of the construction jobs were Kentucky employees, 30,000,000 MMBtu of natural gas was sold per year at $4 per mcf, 12,000 tons per day of carbon dioxide was sold at $10 per ton, 512 MW of electricity would be sold at $0.06 per kwh, and that 2.8 million tons of coal was purchased at $41.50 per ton.

10.0 POTENTIAL FOR GEOLOGIC SEQUESTRATION

The capture and storage of carbon dioxide is driven by the desire to reduce greenhouse gases in the United States. Current research into the viability of carbon storage in geologic formations continues on both a state and national level. As more information about the subsurface becomes available, a more informed decision can be made concerning long-term storage.

Current Capture Technology is limited to acid gas removal using chemical solvents, such as amines, and physical solvents. Commercial scale carbon dioxide capture has not been deployed, but is in the works. The technology has been and is being used to remove smaller amounts of carbon dioxide in the natural gas industry. R&D for new capture technology is being funded in the US, Canada, and Europe. Pilot scale tests are being performed now, but commercialization may be several years off.

Carbon dioxide is currently being transported by pipeline for EOR projects, and new pipelines are being planned. However, pipelines have not been built for transportation in the storage of carbon dioxide from power plants or CTL plants. The total amount of carbon dioxide transported would be much greater than for EOR projects. Researchers in the US, Europe, and Canada are looking at design parameters and providing new construction and maintenance guidelines. The total costs of transportation have not resolved because of uncertainties in the construction costs.

Attached as **Appendix 6** is a report analyzing the potential for geologic sequestration at or near a specific site in Greenup County, Kentucky. This evaluation is provided to demonstrate the type of preliminary analysis that can and should be made during the feasibility phase of a development project. This analysis was performed using research and materials available to the public and in conjunction with the Kentucky Geologic Survey.

The potential targets and seals available at the South Shore site have been discussed. As stated in the report, information available on deep formations is limited to a few wells, seismic data, and interpretation of known areas. As such, this is a preliminary comparison and the addition of future work should be incorporated in future analyses.

For the South Shore project, carbon storage will most likely be to the south and east of the site. On-site deep sequestration is the least viable option at the moment given the storage capacities shown in this report. It should be noted that, whether in deep aquifers or part of an EOR/EGR project, sequestration will require multiple wells over the reservoir area. One injection well will not be sufficient to provide adequate injection rates over a large area.

Future work for sequestration for the site should include discussions with Kentucky, Ohio and West Virginia geological surveys and wells owners for EGR and EOR projects in the larger fields. Identification of actual markets is crucial. Research on carbon dioxide flooding for these fields will also need to be completed.

11.0 LIABILITY, LEGISLATION, PARTNERSHIPS

Evaluation of the liability for carbon dioxide storage and the development of carbon capture and sequestration legislation and regulation must begin with a vision of why this issue is important and the drivers that create a need to sequester carbon dioxide. Any discussion of the legal status of carbon dioxide regulation or legal issues pertaining to carbon capture and sequestration must be qualified with regard to time due to the rapid and unpredictable changes that are associated with the subject.

Comprehensive climate-change legislation does not appear to be viable at this time in the United States Congress. H.R. 2454 (“Waxman-Markey”) passed the House of Representatives in June 2009. In September 2009, S. 1733 (“Boxer-Kerry”) was introduced. Following committee discussion, it was reported out of the Environment and Public Works Committee on November 5, 2009 but made no more progress. Following the fall 2010 elections, it does not appear that legislation is imminent.

Both bills relied upon a “cap and trade” mechanism to reduce carbon dioxide (CO_2 or “carbon”) output in future years. The concept is to place a “cap” upon the upper limit of carbon emissions within the United States. S. 1733 - the more ambitious proposal - envisions a 20 percent reduction in carbon emissions by 2020 and an 80 percent reduction from 2005 levels by 2050. With established limits, carbon emitters will then have the opportunity to “trade” carbon allowances. For example, where it is not feasible for a facility or company to meet their targeted carbon reductions, they will be able to purchase emission credits from others that have reduced their carbon output below target. The goal is to reduce total carbon emissions within the United States while creating a quasi-market mechanism to sort out how to get there.

Hanging over the congressional debate is the U.S. Environmental Protection Agency’s (EPA) actions in proceeding with greenhouse gas emission regulations. The agency is basing its authority to move ahead upon a United States Supreme Court decision[26] that ruled greenhouse gas emissions are pollutants that fall within the EPA's authority under the Clean Air Act. The EPA initialized the process by issuing a proposed "endangerment finding" which has led to initial agency regulation of carbon dioxide and other greenhouse gases.[27] The proposed endangerment finding was sent to the White House on November 6, 2009 and on December 7, 2009, the EPA Administrator announced the final endangerment finding.

The endangerment finding results in a quandary for EPA and the regulated community. GHG are unlike any other pollutant that has been declared a danger to human health and the environment. Other pollutants are subject to severe restrictions beginning at 100 or 250 tons per year. It is patently absurd to regulate GHG at that level. To solve the problem, EPA has issued a "tailoring rule" whereby it has declared that the regulatory threshold for GHG is 25,000 tons per year. EPA has stated that this rule is intended to target only "large facilities" – those that emit more than 25,000 tons of greenhouse gases a year. The EPA has stated that this rule would "cover nearly 70 percent of the national GHG emissions that come from stationary sources, including those from the nation's largest emitters—including power plants, refineries, and cement production facilities."[28] This rule and the endangerment finding are the subject of litigation in the D.C. Circuit court.

Since the endangerment finding, EPA has moved rapidly ahead with a final rule requiring facilities that emit more than 25,000 tons of greenhouse gas emissions (GHG) each year to inventory and report its emissions. This rule has been updated several times as EPA has added additional categories of reporting.

Proposals to add GHG to air permitting became final as of January 2011 with a phased in approach, addressing the newest and largest facilities first.

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[26] Massachusetts et al. v. EPA. Case No. 05-1120. April 2007.

[27] 40 CFR Chapter 1 – "Proposed Endangerment Finding and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act; Proposed Rule." *Federal Register – April 24, 2009*.

[28] "Fact Sheet –Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule." U.S. Environmental Protection Agency. www.epa.gov

The now stymied legislative and active regulatory developments are not free from controversy. Opponents of climate-change legislation maintain that the cap-and-trade policy will impose significant costs upon the American consumer and industry. An analysis conducted by the U.S. Treasury concluded that "economic costs (of cap and trade) will likely be on the order of 1% of GDP, making them equal in scale to all existing environmental regulation."[29] News reports of this Treasury study translated those findings as "a cap and trade law would cost American taxpayers up to $200 billion a year, the equivalent of hiking personal income taxes by about 15 percent."[30]

Proponents of climate-change legislation argue that a significant portion of the allowances are directed toward ensuring that costs borne by consumers are mitigated[31] and that the costs of inaction far exceed the cost of the anticipated policy prescriptions. A 2007 United Nation's study concluded that the global cost of adapting to climate change would range from $47-117 billion annually by 2030.[32] A recent study concluded that the costs anticipated by the 2007 UN study may have been underestimated by nearly 2-3 times.[33]

Notwithstanding the different points of view, action on climate change in the U.S. Congress may be delayed in time but remains a possibility, action by EPA is occurring and litigation by numerous parties is a reality.

11.1 Current Status of Carbon Dioxide Liability

The Kentucky Workgroup for Legal Issues of Carbon Sequestration (**see Appendix 7**) addressed the types of liability that are inherent in the capture and storage of carbon dioxide.

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[29] United States Department of Treasury. Response to FOIA No. 2009-04-09.

[30] CBS News – Declan McCullagh – Taking Liberties Blog Post. 9/15/2009.

[31] "Analysis of H.R. 2454, the American Clean Energy and Security Act." National Resources Defense Council

[32] United Nations Framework Convention on Climate Change.

[33] "Assessing the Costs of Adaptation to Climate Change." Grantham Institute for Climate Change – Imperial College, London England. Aug. 2009.

Liability for stored CO_2 can fall in one of three pots: liability for regulatory violations, for lost carbon credits or tort liability. Similarly, liability can arise at different points in the timeline of a storage facility: during active storage, during the near-term post closure period, or during the long term of storage reaching into the future.

- *The act of storing carbon dioxide will be regulated under EPA's injection well rule or by states with primacy over that program. Violations of those regulations and the permits issued under those regulations will result in fines and clean-up responsibilities for the permitted entity.*
- *Carbon storage will likely be subject to credits or the avoidance of cost, while also being subject to the cost of storage. Should the stored carbon escape, all those who received the credit or benefit of storage may be subject to repay that amount, together with penalties or other assessments.*
- *An accident while constructing the well or injecting the carbon could result in tort liability, arising from personal injury or injury to property. Although it appears unlikely, a catastrophic failure of a system would also result in tort liability.*

Failure of a system could result in all three types of liability attaching from the same event. For example, if the stored CO_2 migrates into the drinking water strata, making the water unusable, a cause of action in tort may arise, in addition to violations of the Clean Water Act and permit conditions. At the same time, the entity which was credited with storage may have to address the loss of that credit due to atmospheric release of the sequestered carbon.

It appears that certain of these liabilities can be addressed through normal insurance products and bonding requirements, as they have for years for normal well drilling and permitting actions. Storage of CO2 as a gas bears similarities to the geologic in-formation storage of natural gas by regulated utilities. It is the long-term responsibility for keeping the CO_2 stored that is less likely to be adequately addressed with traditional indemnity products. If we require the CO_2 to be stored for a substantially long time, or permanently returned to the earth, who will be responsible years after the storage well is closed and properly abandoned? Entities that may seem the logical carriers of this responsibility are likely to disappear, or go out of business. Where then can we look for the long term monitoring and responsibility for corrective action if an issue ever arises?

Several states have begun to address this question through legislative action.[34] *Their action reflects suggestions made in numerous reports published by study groups.*[35] *Further, the European Union has issued a directive which must be implemented by member countries by Spring 2011 that suggests that responsibility for the long term storage and monitoring can be transferred to the state at 20 years following closure or greater.*[36] *Australia, in the Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill 2008, allows transfer of liability to the state after 20 years monitoring of a closed storage facility.*

The deployment of the technology of carbon storage has not progressed to the point of having its associated liabilities tested in the courts. Numerous studies and policy recommendations have posed potential solutions for addressing these potential liabilities which range from commercial insurance coverage, to pre-funding long term liability with a per ton fee, to state or federal adoption of those liabilities. Each of these will likely have a role to play. At this time, legislation appears to be where activity is centered with regard to liability.

Unusual among the proposals at the state level is the approach currently under review with the West Virginia Carbon Dioxide Working Group. This group was formed by legislative mandate to evaluate numerous technical and legal aspects of CCS technology. In its draft report (see **Appendix 7**), the group has indicated that it will pose an approach to accessing pore space which finds that if the pore space strata is below 2,500 feet below ground surface and does not have a reasonably foreseeable use for a purpose other than sequestration, there is no requirement to obtain permission or provide payment for the use of that strata as that will be dedicated to the public use. While this approach reflects discussions from the Midwest Governors Association, it has not been implemented elsewhere at this time.

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[34] Louisiana (HB 661); Montana (SB 498); North Dakota (SB 2095). Pennsylvania has determined that the state will own the CO2 stored within its CCS network (HB 80).

[35] e.g., "Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces", IOGCC, September 25, 2007

[36] EU Directive 2009/31/EU

11.2 Development of Legislation - Carbon Capture and Sequestration

Carbon capture is likely to be addressed substantially by the federal government through regulation and possibly statute. Sequestration may be mandated or may become a likely solution to the limitations on emissions, but facilitating legislation for sequestration will likely come from the states. The exception to that rule is the permitting of sequestration facilities as Class 6 injection wells. EPA has completed its rule making on this issue although there are few takers at this time. The majority of activity injecting carbon dioxide is in the enhanced oil recovery (EOR) field or demonstration or research wells. EOR is a technique that has been practiced for decades, primarily in the Texas and Oklahoma oil fields. As a result, there are currently over 4000 miles of carbon dioxide pipelines in use in the U.S. EOR is generally excluded from regulation and legislation addressing carbon dioxide sequestration.

Test or research wells are permitted as Class 5 injection wells. The permitting agency will be determined by primacy, the method by which EPA delegates permitting authority to the states.

The deployment of carbon sequestration will primarily impact state law, addressing matters of property rights and ownership that are not decided on the federal stage.

Following is a summary of state legislation enacted or considered as of September 30, 2010. The issues surrounding carbon sequestration and transportation will be an area of active legislative attention for several years to come. Several of these proposals may have been adopted or failed and new proposals will be introduced.

11.2.1 States (Enacted)

California (Public Utilities Code section 8340-8341): geologically sequestered carbon dioxide does not count toward emissions from Utilities.

California (Public Utilities Code section 181000-181016): Allows Sonoma Transportation Authority to utilize carbon sequestration opportunities.

California (Health and Safety Code section 38560-38565): State board shall adopt rules and regulations to achieve maximum technically feasible and cost effective greenhouse gas emission reductions which include carbon sequestration projects.

Colorado (Chapter 40 Article 9.7 “Colorado Clean Energy Development Authority Act”): Allows for utilities to use carbon sequestration as a method to reduce carbon dioxide emissions. The commission shall consider proposals by Colorado electric utilities to propose, fund, and construct IGCC generation facilities to demonstrate the feasibility of clean coal technology with use of western coal and with carbon dioxide capture and sequestration.

Illinois (SB 1987 – Introduced & Passed 2008 – became Public Act 095-1027): Requires electric utilities as of December 31, 2005, that serviced at least 100,000 customers in the state to enter into contracts to obtain at least 5 percent of their supply from facilities employing CCS. Defines “clean coal facilities” as those scheduled to begin operations before 2016 which capture and sequester at least 50 percent of total carbon emissions and facilities scheduled to begin operations after 2017 which capture at least 90 percent of total carbon emissions must be captured and sequestered.

Illinois (HB 3854 – Introduced & Passed 2009): Created a Carbon Capture and Sequestration Legislation Commission to report on all issues related to carbon capture and sequestration, including but not limited to: ownership of the CO_2, liability for release of CO_2, acquisition and ownership of pore space, procedures and safeguards for the transportation and sequestration of CO_2, methodology to establish any necessary fees, potential use of CO_2, construction of pipelines and coordination with federal authorities and agencies. The commission is to expire after the report is issued.

Illinois (SB 0390 – Introduced & Passed 2009 became Public Act 96-0817): Amends the Illinois Finance Authority Act. Includes an Energy Efficiency Project as a project eligible for financing under specified provisions. Includes CO2 pipeline as a “Clean Coal Project” and is eligible for bond issuance by the state.

Illinois (SB 1906 Introduced and Passed became Public Act 096-0103): Sets forth criteria for approving out-of-state CCS projects.

Kansas (Kansas Statutes Chapter 55 Oil and Gas Article 16) – Provides definitions and commission powers for regulating injection of carbon dioxide. It establishes a carbon dioxide injection well and underground storage fund.

Kentucky (HB 537 – Introduced & Passed 2009): Proposed the creation of a carbon management legal issues study group "to identify and analyze legal issues that may hinder development of solutions of carbon dioxide in Kentucky."

Louisiana (SB 10 – Introduced and Passed 2009): Excluded the sale of anthropogenic carbon from the state and local sales and use tax. Granted a 50 percent reduction in severance tax within a carbon dioxide tertiary recovery project.

Louisiana (Revised Statute 30:209 State Mineral and Energy Board): Allows for the board to create caverns in salt domes for carbon dioxide storage, establish carbon dioxide storage facility in an underground reservoir, take over abandoned surface or underground storage to maximize the useful life of the existing facility, and establish a contractual agreement for the operation of a carbon dioxide storage facility for the storage and distribution of carbon dioxide for secondary or tertiary recovery operations.

Louisiana (Revised Statute 30:1110 Carbon Dioxide Geologic Storage Trust Fund): The fund shall be used solely for the following purposes: (1) Operational and long-term inspecting, testing, and monitoring of the site, including remaining surface facilities and wells; (2) Remediation of mechanical problems associated with remaining wells and surface infrastructure; (3) Repairing mechanical leaks at the site; (4) Plugging and abandoning remaining wells or conversion for use as observation wells; (5)(a) Administration of this Chapter by the commissioner in an amount not to exceed seven hundred fifty thousand dollars each fiscal year; (b) The Oil and Gas Regulatory Fund created by R.S. 30:21 may be used for the administration of this Chapter as authorized by this Paragraph until June 30, 2014. Any such payments from the Oil and Gas Regulatory Fund shall be repaid from the Carbon Dioxide Storage Trust Fund by

June 30, 2018; (6) Payment of fees and costs associated with the administration of the fund or site-specific accounts; (7) Payment of fees and costs associated with the acquisition of appropriate insurance for future storage facility liability if it should become available, either commercially or through government funding. The commissioner is authorized to enter into agreements and contracts and to expend money in the fund for the following purposes: (1) To fund research and development in connection with carbon sequestration technology and methods; (2) To monitor any remaining surface facilities and wells; (3) To remediate mechanical problems associated with remaining wells or site infrastructure; (4) To repair mechanical leaks at the storage facility; (5) To contract with a private legal entity pursuant to this Chapter; (6) To plug and abandon remaining wells except for those wells to be used as observation wells.

Louisiana (Revised Statute 30:23 Underground Storage of liquid or gaseous hydrocarbons or both or carbon dioxide): It restricts use of salt domes without further regulatory action.

Louisiana (Revised Statute 30:1104 Duties and Powers of the commissioner): This statute allows for rules, regulations, and permitting of carbon storage facilities.

Montana (Codified in Chapter 69): allows for carbon dioxide transmission, establishment of rates and rules under the common carrier pipeline.

Montana (Codified in Chapter 77 (77-3-430)): allows for pooling agreements for carbon dioxide sequestration.

Montana (S.B. 498 – Introduced and Passed 2009): Granted ownership of pore space to surface owners unless it could be determined from existing deeds or severance documents to be otherwise. Established a fee on CO_2 storage to fund the state's monitoring of storage sites and program administration. Liability for CO_2 remains with the storage operator until a certificate of closure is issued by the state, at which time title is transferred to the state.

New York (General Municipal Law 959-b. Clean Energy Enterprises): allows for sequestration projects to apply under this section for economic development.

North Dakota (S. 2221 – Introduced and Passed 2009): Granted a 20% tax reduction against the state coal conversion tax for those electricity generating plants and coal conversion facilities that reduce CO_2 output by twenty percent. Higher tax abatements were allowable if CO_2 reductions exceeded twenty percent, with the maximum allowable amount reaching 50% for an eighty percent reduction in CO_2 output.

North Dakota (S. 2095 – Introduced and Passed 2009): Placed authority over carbon capture and storage activities under the North Dakota Industrial Commission. Authorized the commission to collect a fee from storage operators on a per-ton basis. Title and liability for the sequestered carbon remain with the storage operator while site is active. A certificate of closure can be issued by the Commission no earlier than 10 years after carbon injections have ended. Once certificate of closure is issued, the state gains title and responsibility for the storage facility.

North Dakota (S. 2139 – Introduced and Passed 2009): Vested ownership of pore space with the surface owners. Prohibited the severance of pore space ownership from surface ownership.

Oklahoma (SB 610 Geologic Storage of Carbon Dioxide Act Approved by Governor 2009): Department of Environmental Quality will have exclusive jurisdiction for permitting and regulating CCS facilities. Storage operators in this state and pipeline operators in this state will be deemed to be public utilities providing public services and are subject to the general power of the public service commission to regulate public utilities.

Tennessee (Codified 67-6-232): Carbon capture and sequestration projects are eligible for a credit on all state sales or use taxes paid to the state.

Texas (SB 1387 – Introduced and Passed 2009): Granted jurisdiction over the geological storage and injection of carbon dioxide to the Texas Railroad Commission and giving permitting power to the Commission to approve projects. Defined the owner of the sequestered carbon dioxide as the “storage owner” and not the surface or mineral estate. Created the Anthropogenic Carbon Dioxide Storage Trust Fund to resource the

Railroad Commission's authority to inspect, monitor, remediate and/or repair carbon dioxide injection wells. Required the Railroad Commission to establish rules about the extraction of sequestered carbon for commercial or industrial purposes.

Utah (Code Title 10 Chapter 19 Municipal Electric Carbon Emission Reduction Act and Title 54 Chapter 17 section 601): Defines "qualifying carbon sequestration generation" as a fossil-fueled generating facility that reduces carbon dioxide emissions by permanent geological sequestration.

Utah (Code Title 54 Chapter 17 Energy Resource Procurement Act Section 701 (54-17-701)): Mandates by Jan. 2011 the Division of Water Quality and the Division of Air Quality in collaboration with Division of Oil, Gas, and Mining and Utah Geological Survey recommend for: site characterization approval; geo-mechanical, -chemical, and hydrogeological simulation; risk assessment; mitigation and remediation protocol; issuance of permits for test, injection, and monitoring wells; specifications for drilling and completion of wells; monitoring, measurement, and verification or sequestration; closure and decommissioning; EOR use; and short-, long-term liability and indemnification for sequestration sites.

Utah (S.B. 202 – Introduced and Passed 2008): Directed a variety of state agencies to develop and recommend rules for carbon capture and storage. Specifically stated that the proposed rules would not apply to the "injection of fluids…for the purpose of enhanced hydrocarbon recovery."

Washington (Administrative Code WAC 173-218-115): Provides specific requirements for Class V wells used to inject carbon dioxide for permanent geologic sequestration under the State waste discharge program.

West Virginia (HB 2860 – Introduced and Passed 2009): Established the statutory authority for the West Virginia Department of Environmental Protection to issue permits for carbon storage. Established a working group to study issues pertaining to carbon dioxide sequestration including, but not limited to, scientific, technical, legal and regulatory issues, and issues regarding ownership and other rights and interest in subsurface space that can be used as storage space for carbon dioxide and other associated constituents, or other substances, commonly referred to as "pore space," and shall report to the secretary and the Legislature its recommendations with respect to the development, regulation and control of carbon dioxide sequestration and related technologies.

Wyoming (HB 89 and HB 90 – Introduced and Passed 2008): These companion bills conferred ownership of pore space to the surface owner and legislated that the conveyance of surface ownership also included ownership over pore space, unless specifically severed. Directed the Wyoming Department of Environmental Quality to institute a program for issuing permits for and regulating long-term geological carbon sequestration.

Wyoming (HB 80 – Introduced and Passed 2009): Adopted a new procedure for "unitizing" geologic sequestration sites used for the sequestration of carbon dioxide. Unitization provides a means for all pore space owners to participate in a sequestration project and assures that all such owners will share in the economic benefits of a sequestration project.

Wyoming (HB 58 – Enrolled Act. 20, effective July 2009): All injected CO2 into any geologic sequestration site will be presumed to be owned by the injector and all rights, benefits, burdens and liabilities of ownership will belong to the injector. Owner of pore space will not be liable for the effects of injecting carbon dioxide for geologic sequestration purposes solely by virtue of their interest or by their having given consent to the injection.

Wyoming (HB17 - Carbon sequestration-financial assurances and regulation; Effective July 1, 2010): Funds in the account shall be used only for the measurement, monitoring and verification of geologic sequestration sites following site closure certification, release of all financial assurance instruments and termination of the permit.

11.2.2 States (Proposed)

Indiana (HB 1412 – Introduced 2009 died): Proposed incentives for alternative energy purchases. Provides that purchases of energy, capacity, or renewable energy credits from alternative energy sources are eligible for the financial incentives available for clean coal and energy projects. Specifies that "clean coal and energy projects" include projects at new or existing energy facilities that involve carbon dioxide capture, storage, and sequestration. Requires the utility regulatory commission (IURC) to allow an energy utility that purchases alternative energy to recover any costs arising under the purchase contract through rate adjustments.

Indiana (SB 0211 Introduced 2010): Delineates the jurisdiction of the department of environmental management, the utility regulatory commission, and the department of natural resources with respect to various aspects of carbon dioxide transportation and storage.

Indiana (SB 0115 Introduced 2010): Eminent domain for carbon dioxide pipeline. Permits an entity authorized to transport carbon dioxide by pipeline to acquire real property by eminent domain.

Kentucky (HB 285 – Introduced 2009 died): Proposed that the Kentucky Economic Development Finance Authority to grant financial incentives to a pilot project with a minimum $100 million capital investment that is utilizing advanced carbon capture and storage and received federal funding as a clean energy initiative. It allowed for the project to be a modification of an existing coal-fired generating station with at least 300 MW of rated capacity.

Kentucky (HB 351 – Introduced 2009 died): Proposed that the Commonwealth of Kentucky would "accept and receive all rights, title and interests in sequestered (carbon) including any current or future environmental benefits, marketing claims, tradable credits, emission allocations or offsets (voluntary or compliance based)."

Kentucky (HB213/LM Introduced 2010): Creates a new section of KRS Chapter 154 to allow transmission pipeline companies to condemn for lands and materials needed to construct, operate, and maintain a carbon dioxide transmission pipelines; require the proceedings be the same as under the Eminent Domain Act of Kentucky; declare that the pipeline is a public use; amend KRS 154.27.010 to include transmission pipeline under the definition of "eligible project" and define "transmission pipeline"; amend KRS 154.27-020 to require a transmission pipeline to have a capital investment of $50,000,000 to qualify for energy independence incentives; and amend KRS 353.500 to include transmission of carbon dioxide for enhanced oil recovery, sequestration, or other carbon management under the jurisdiction of the state for purposes of regulation.

Kentucky (HB491 Introduced 2010): Creates new sections of KRS Chapter 353 declaring carbon dioxide management and storage to be important goals; declare certain geologic strata to be the property of the Commonwealth; direct the Division of Oil and Gas Conservation to develop a regulatory plan for development of geologic carbon dioxide storage including condemnation powers; provide minimum requirements for permitting; create an assessment against carbon dioxide generators per ton of carbon dioxide stored; direct the secretary of the Environmental and Public Protection Cabinet to negotiate with bordering states to resolve issues of geologic carbon storage; create the Kentucky Carbon Storage Authority to take ownership of closed and stable carbon storage facilities; create the Kentucky carbon storage fund for management and liability of closed carbon storage facilities; create mechanism for assessment fee to be adjusted.

Kentucky (HB 588 Introduced 2010): Create a new section of Subchapter 27 of KRS Chapter 154 to authorize tax incentives under the Incentives for Energy Independence Act to be awarded to certain carbon capture and storage projects that have received incentives from the United States Department of Energy.

Michigan (SB 775 Introduced 2009): It allows for condemnation, establishes a Carbon Dioxide Storage Facility Fund for long-term monitoring etc., after Notice of Completion – 10 years after completion state takes ownership. THE DEPARTMENT AND LOCAL UNITS OF GOVERNMENT MAY ENTER INTO AGREEMENTS WITH EACH OTHER AND WITH THE FEDERAL GOVERNMENT OR OTHER STATES FOR THE

PURPOSE OF REGULATING CARBON DIOXIDE STORAGE PROJECTS OR OWNING OR OPERATING STORAGE FACILITIES. **Reported favorably with recommendation for referral to committee on Energy Policy and Public Utilities – 9/17/09**

Michigan (HB 4016 Introduced 2009) - Michigan business tax act amendment provides for a tax credit up to 50% of tax liability for carbon sequestration projects.

Mississippi (SB 2867 Introduced and died 2010): Clarify the authority of the Oil and Gas Board to authorize the underground storage of carbon dioxide. Allows the Board to enter into an order to allow carbon sequestration

Missouri (HB 2038 Introduced 2010): Limits the liability of any entity in cases of personal injury or death arising from or related to the geologic sequestration of carbon dioxide or other specified gases in Greene County.

New Mexico (HB 790 Introduced & Died 2009): Carbon Dioxide Sequestration Enabling Act defined Pore space is owned by the surface owner. It may be severed from the surface. Carbon dioxide ownership remains with the operator.

New Mexico (SB 234 Introduced & Died 2009): The NM Tech Carbon Sequestration Project -Four hundred thousand dollars ($400,000) to be appropriated from the general fund to the board of regents of New Mexico institute of mining and technology for expenditure in fiscal year 2009 to provide matching money for the petroleum recovery research center's federal carbon sequestration project.

New York (A05836 – Introduced & Died 2009): Proposed that the ownership of “all pore space in all strata below the surface lands and waters…to the several owners of the surface above the strata.” Proposed a process by which a carbon capture and storage pilot project would be permitted and authorized.

New York (A00249 same as S4917 Introduced 2010): Establishes the New York state greenhouse gases management research and development program to promote new technologies and processes which shall avoid, abate, mitigate, capture or sequester carbon dioxide and other greenhouse gases.

New York (A05836A Introduced 2010): the ownership of all pore space in all strata below the surface lands and waters of this state is declared to be vested in the several owners of the surface above the strata.

New York (Bill A08802 same as S06163 and S53303 Introduced 2010): Relates to a pilot program to enable the capture and storage of carbon dioxide; establishes the carbon capture and sequestration act; applies only to a municipally-owned electric generating facility that has submitted a complete application to the department of environmental conservation by December 31, 2010.

New York (Bill S05971 Introduced 2010): Relates to a pilot program to enable the capture and storage of carbon dioxide; establishes the carbon capture and sequestration act; applies only to a municipally-owned electric generating facility that has submitted a complete application to the department of environmental conservation by December 31, 2010.

Oklahoma (SB 492 – Introduced & Died 2009): Proposed that the Oklahoma Department of Environmental Quality to issue “temporary, time-limited permits for pilot-scale testing of technologies for geological sequestration.” The utilization of CO_2 in enhanced oil recovery was exempted unless the oil and gas well was converted to geological sequestration.

Oklahoma (SB2024 Introduced 2010): This act shall be known and may be cited as the "Oklahoma Carbon Capture and Geologic Sequestration, Transportation and Investment Act". In the event the State of Oklahoma establishes a unitization process to support the establishment of CO2 sequestration facilities in this state, the Corporation Commission shall regulate all aspects of such process, including being responsible for making any necessary findings concerning the suitability of the reservoir targeted for carbon sequestration, whether its use for such purpose is in the public interest, and the impact of that use on the oil, gas, coal-bed methane and mineral brine resources in the State of Oklahoma.

Oklahoma (SB1326 Introduced 2010): Geologic storage of carbon dioxide; recreating the Oklahoma Geologic Storage of Carbon Dioxide Task Force. The task force shall continue to study any issues necessary to implement the transmission and storage of carbon dioxide in geologic formations, including, but not limited to, insurance, liability and ownership issues relating to long-term carbon dioxide storage facilities and the task force shall make a report which may include legislative recommendations following the termination of its activities.

Pennsylvania (HB 80 Introduced and Died 2010): An Act amending the Alternative Energy Portfolio Standards Act. It further provides for definitions and for alternative energy portfolio standards; and providing for sequestration facility permitting and for title to carbon dioxide, immunity and transfer of liability; establishing the Carbon Dioxide Indemnification Fund; providing for carbon dioxide sequestration facility and transportation pipeline on Commonwealth State forest lands; and providing for application of the Public Utility Code to transporters of carbon dioxide.

Pennsylvania (SB 92 Introduced 2010): An Act amending the Alternative Energy Portfolio Standards Act. It further provides for definitions and for alternative energy portfolio standards; and providing for carbon dioxide sequestration network.

Tennessee (HB 3046 (same as SB 2912) Introduced 2010): As introduced, adds carbon dioxide as a pipeline product that is regulated by the Tennessee regulatory authority. - Amends TCA Title 65, Chapter 28, Part 1.

Texas (SJR 39 – Introduced & died 2009): Proposed a constitutional amendment authorizing the issuance of general obligation bonds by the State of Texas to provide and guarantee loans for clean energy projects. In order to qualify, an energy project needed to capture and sequester not less than 50 percent of its carbon emissions.

Texas (SB 2111 / HB 2811 – Introduced & Died 2009): Companion bills introduced to enact SJR 39. Exempted components of tangible personal property used in connection with geological sequestration and enhanced oil recovery from tangible personal property taxes. Required that a permit for a clean energy project be rejected or denied within nine months (with a possible three month extension) after the application was deemed technically complete. Granted jurisdiction over the geological storage and injection of carbon dioxide to the Texas Railroad Commission.

Texas (SB 483 Introduced & Died 2009): Clean coal projects with incentives. Comptroller will adopt rules for issuing a franchise tax credit to promote research and development of a clean energy project. Franchise tax credit may only be issued for the first three clean energy projects that are fully operational. Clean Energy Project means a project that will: have a 200 megawatt capacity, use integrated gasification combined cycle technology, and be capable of CCS for at least 60% of CO2. Univ. of Texas will monitor, measure, verify sequestered CO2.

Virginia (SB 247 Introduced 2010): Adds Title 45.1 a chapter numbered 23.1 relating to the regulation of the geologic storage of carbon dioxide. Gives authority to regulate to the Director of Natural Resources.

If the storage facility contains commercially valuable minerals, a permit may be issued only if the Director is satisfied that the interests of the mineral owners or mineral lessees will not be adversely affected or have been addressed in an arrangement entered into by the mineral owners or mineral lessees and the storage operator

The storage operator retains title to the carbon dioxide injected into and stored in a storage reservoir until the Director issues a certificate of project completion pursuant to § 45.1-380.7. The storage operator remains liable for any damage the carbon dioxide may cause, including damage caused by carbon dioxide that escapes from the storage facility, during the time in which he holds title to the carbon dioxide.

After 10 years, the operator may be released from liability stemming from the geologic storage of carbon dioxide if he is able to demonstrate the integrity of the facility. Title to the carbon dioxide and any liability related to the project then passes to the Commonwealth.

Creates the Carbon Dioxide Storage Facility Trust Fund. The Fund shall be used solely for long-term monitoring of the storage facility, including remaining surface facilities and wells, remediation of mechanical problems associated with remaining wells and surface infrastructure, repairing mechanical leaks at the site, and plugging and abandoning remaining wells under the jurisdiction of the Director for use as observation wells.

Wyoming (HB 56 – Introduced 2009): Proposed that no pore space containing recoverable hydrocarbons be used for carbon sequestration without the written consent of the owner of the oil and gas lease.

11.3 Selected International Legislative Developments

During the summers of 2009 and 2010, SMG was fortunate to have two Swiss engineering students as interns. Among their duties was a charge to research and summarize legislative developments in the European Community and other selected jurisdictions. The following section represents their work as of the date of their internship.

11.3.1 Summary - European Community

Introduction

On January 23, 2008, the European Commission put forward a far-reaching package of proposals (“Climate Action and Renewable Energy Package”) that are intended to deliver on the European Union's ambitious commitments to fight climate change and promote renewable energy to 2020 and beyond. This included the issue of the Directive on the geological storage of carbon dioxide (2009/31/EC), which was adopted by the European Parliament in December 2008.

This directive recites the goal of global reduction of greenhouse gas emissions of 50% by 2050, and states that reduction is technically feasible and the benefits outweigh the costs by far. To achieve the goal, “all mitigation options must be harnessed” including carbon dioxide capture and geological storage (CCS).

Directives in the EC are legislative acts which require Member States to achieve a particular result without dictating the means of achieving that result. The Directive will have to be implemented by all Member States within two years of its coming into effect (i.e. sometime in the Spring of 2011). Therefore, the legislation process on CCS in most of the European states has commenced.

This directive only regulates and allows geological storage, either onshore or offshore. Storage in the water column is specifically prohibited. Capture and transport of CO2 are partly addressed in the Directive as a number of legislative instruments (c. f. “Directive on Industrial Emissions”, 96/61/EC or “Directive on Environmental Impact Assessment (EIA)”, 85/337/EC) are already in place to manage some of the environmental risks of CCS.

The directive on CCS only regulates the storage of CO2 inside the European Union and the European Economic Area (when incorporated into the EEA Agreement, as it is expected), and the storage of CO2 beyond this area is not permitted. However, storing CO2 emissions outside the European Union (and EEA) is not banned, but any emissions so stored will receive no credit under the EU Emission Trading System (ETS), thus providing little incentive to store carbon dioxide abroad.

Legislation

a) Site selection, exploration and storage permits

Member States retain the right to determine the areas from which storage sites may be selected. A geological formation shall only be selected as a storage site, if under the proposed conditions (intrinsic characteristics such as reservoir geology, hydrogeology, seismicity or presence and condition of natural and man-made pathways which could provide leakage pathways) there is no significant risk of leakage, and if no significant negative environmental or health impacts are likely to occur.

Member States assign exploration permits which grant the holder to exclusively explore a limited volume area and for a maximum of two years, renewable once for a maximum of two years.

The Member States designate an authority which is competent for granting storage permits upon application. When applying for a storage permit, an operator must supply the following information:

- proof of competence,
- a detailed characterization and assessment of the potential site,
- information regarding the CO2 to be injected (the total quantity of CO2 to be injected and stored, the prospective sources and transport methods, the composition of CO2 stream, the injection rate and location of injection facilities),
- a description of measures to prevent significant irregularities,
- a monitoring plan and a corrective measure plan,
- an environmental impact assessment, and
- a post closure plan backed up by proof of financial security to cover closure and potential leakage liabilities.

b) Operation, closure and post-closure obligations

During operation:

A CO2 stream has to consist overwhelmingly of carbon dioxide. It is the operator's responsibility to show, by means of the appropriate documentation, that the CO2 stream in question can be accepted at the site according to the conditions in the permit.

The operator carries out monitoring of the injection facilities, the storage complex and the surrounding environment. The results of the monitoring are periodically reported to the competent authority, which will also organize a system of routine and non-routine inspections.

In case of significant irregularities or leakages, the operator has to notify the competent authority immediately and takes the necessary corrective measures. If the operator fails to take the necessary corrective measures, the competent authority shall take the necessary corrective measures itself and recover the costs from the operator.

Furthermore, free and fair third-party access must be provided by the operator.

Closure and post-closure obligations:

After the storage site has been closed the operator remains responsible for maintenance, monitoring, control, reporting, and corrective measures, as well as for all ensuing obligations under other relevant revisions of Community legislation, until the responsibility for the storage site is transferred to the competent authority.

The responsibility can be transferred to the competent authority on its own initiative or upon request from the operator (at earliest 20 years after closure) if and when all available evidence indicates that the stored CO2 will be completely contained for the indefinite future.

Process of Negotiation

The agreed Directive differs from the original proposals in a number of key ways:

- it now explicitly recognizes that carbon dioxide storage can take place in tandem with the enhanced recovery of hydrocarbons;
- multiple uses of the same region of the sub-surface are now permitted;
- the requirements before responsibility for a storage site can be transferred to a competent authority have been significantly strengthened and more detail is provided on how these requirements are to be met;
- the competent authority must now charge a fee before accepting long-term responsibility for a storage site, the level of which must cover at least the anticipated costs of monitoring the storage site for a period of 30 years after closure; and

- the original version of the draft Directive required applicants for new combustion power generation stations to undertake technical assessments of transport, storage and the feasibility of retrofitting carbon capture. It also required appropriate space on site to be set aside to accommodate such technology. The agreed Directive now requires an assessment of whether suitable storage is available, as well as technical and economic assessments of transport and retrofitting, but only requires space to be set aside if these other assessments show CCS is ultimately feasible.

Emission Standards

The EU emissions trading system (ETS) is today the only EU instrument to combat emissions from large emission points. To de-carbonize the power sector in Europe, CO2 emission performance standard (EPS) are needed. The Directive including amendments on EPS is not expected to be adopted by the European Parliament and the Council of Ministers until 2011.

In January 2009, several NGOs criticized the revised EU ETS for allowing the construction of new power plants "under the guise of 'CO2-capture readiness'.[37] They proposed a limit of 350g CO2/kWh for new plants from 2010 and for existing plants from 2015, which could cut power sector emissions by up to 46%, while stricter limits imposed on new plants only would deliver much smaller savings.

Next steps

The “Climate Action and Renewable Energy Package” seeks to promote the development and safe use of CCS. Revised guidelines on state aid for environmental protection will enable governments to support CCS demonstration plants.

CCS measures are now fully recognized as sinks by the EU Emission Trading System ETS.

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[37] “EU Urged to Introduce Emission Limits for Power Plants,” [cited 14 January 2009]; available from http://www.euractiv.com/en/climate-change/eu-urged-introduce-emission-limits-power-plants/article-178482.

11.3.2 Summary - United Kingdom (UK)

Based on the EU Directive adopted in December 2008 and the UK Energy Act 2008, the United Kingdom initiated the consultation “Towards Carbon Capture and Storage”, which was intended to help to more broadly inform what is meant by carbon capture readiness and whether it should be required of new plants.

The Government’s response on this consultation in April 2009 set out its approach to carbon capture readiness: New combustion power stations at or over 300 MWe (Megawatt electric) have to be built Carbon Capture Ready (CCR), which means that the facility is designed so that there are no foreseeable barriers to retrofitting CCS once it is proven.

Applications for new plants now are only considered if they:

- Confirm sufficient space available to retrofit CCS
- Identify a suitable potential offshore area to store CO2
- Map a feasible potential transport route from the power plant to the storage area
- Do not have foreseeable barriers to retrofitting CCS

Nothing in the consultation responses challenged the crucial importance of CCS for the de-carbonization of power generation or the consultation’s arguments for CCR as a low cost risk insurance policy.

In June 2009, the Department of Energy and Climate Change published a document under the title “A Framework for the Development of Clean Coal: Consultation Document”. This proposal, adopted in November 2009, included the following main propositions:

- Providing financial support for up to three more commercial-scale CCS demonstrations in Britain;
- Requiring any new coal power station in England and Wales to demonstrate CCS on a defined part of its capacity;

- Requiring new coal power stations to retrofit CCS to their full capacity within five years of CCS being independently judged technically and economically proven. This is planned on the basis that CCS will be proven by 2020;
- Preparing for the possibility that CCS will not become proven as early as expected.

11.3.3 Summary - Germany

At the present, Germany has one active research storage project. The German Research Centre for Geosciences has started to store CO2 in a saline aquifer in Ketzin, Brandenburg in June 2008. Several other initiatives have been undertaken such as Vattenfalls's pilot capture demonstration plant Jänschwalde.

The German government drafted legislation in April 2009 encouraging the take up of carbon capture and storage (CCS) technology in the country. The draft follows the Directive of the European Union. However, it specifies important time periods. For instance the post-closure responsibility can be transferred to the competent authority on upon request from the operator at the earliest 30 years after the closure activities have finished. A financial post-operation contribution from the operator has to cover the post-closure operation costs for another 30 years after the transfer of the responsibility.

Germany has not released any emission performance standards yet.

11.3.4 Summary - Norway

Directive on the geological storage of carbon dioxide applies also on the non-EU-member Norway, because Norway is part of the European Economic Area (EEA). Norway is one of the countries with best experience in the field of CCS. The Sleipner project in the Sleipner gas field in the North Sea was the first industrial-scale CO2 storage project in the world, and the operators have established extensive monitoring procedures, including models to predict long-term movement of CO2. Since 1996 when injections began, more than 10 million tons of CO2 have been stored.

Although Norway has more than 10 years' experience with CCS, no specific rules exist in Norway to regulate the activity. CCS projects carried out in Norway have been addressed on a case by case basis with support from existing environmental legislation and legislation applicable within the petroleum sector. However, these regulations have not had CCS in mind, and they are not sufficient to address all legal aspects of CCS activities, either when conducted in a pure Norwegian context or in a European context implying an open market.

Current regime for CCS in Norway

The State has the property right to underground petroleum resources and other natural resources located on the Norwegian Continental Shelf and the land territory. As owner, the State has the exclusive right to decide and to control such use and to regulate all aspects regarding CO2 storage. The right to use reservoirs is subject to a permit, delivered in the form of a lease.

According to the "Norwegian Oil and Energy Department", Norway's Petroleum Act provides an acceptable (Petroleum Act of 29 November 1996 nr.72) framework to regulate most issues associated with injections connected with petroleum activities: exploration, development and management of the installation, coordination with competing rights, third party access, decommissioning and safety measures. However, some important issues such as long term monitoring and long term liabilities are not addressed upfront.

Therefore, the Norwegian Oil and Energy Department states that the scope of application of the Petroleum Act should be extended or specific provisions should be adopted in order to cover injection and storage which are not connected to petroleum activities. Specific rules regarding transfer of responsibility, however, would need to be adopted.

A Petroleum Bill, dated November 2008, provided specific modifications to the Petroleum Act. Among the modifications were provisions regarding third party access to the petroleum installations. The consultation document also suggested that CO2 storage activities not connected to petroleum activities be regulated through the Petroleum Act.

Other parties such as the CCS-friendly Norwegian environmental foundation “Bellona” have requested that CO2 storage legislation not be connected to petroleum activities.

11.3.5 Summary - Australia

Current Legislation and Regulation

In Australia, some states have legislation/regulations that cover CCS. The South Australian Petroleum Act 2000 and the Queensland Petroleum and Gas Act 2004 provide for transport by pipeline and storage in natural reservoirs of substances including carbon dioxide, regardless of the source location or the activity that produced it. There is also other legislation in jurisdictions that applies to aspects of CCS. For example, the Commonwealth and State Petroleum Acts provide a mechanism for authorizing and regulating the capture and storage by a production licensee of carbon dioxide separated from the petroleum stream in a license area, as part of integrated petroleum operations of the licensee. CCS streams from other sources (e.g. from a power station onshore or other offshore petroleum operations) cannot at present be authorized for offshore CCS under the current regulations.

In 2005, the federal Regulatory Guiding Principles highlighted a number of areas which required careful consideration in preparing regulation on carbon capture and storage. Work to implement a regulatory framework identified 12 threshold questions that had to be addressed.

1) What legislation should be used to provide the access and property rights?
2) What management system is needed for the release and award of exploration areas?
3) What regulation is needed to manage environmental issues?
4) What regulation is needed to manage occupational health and safety issues?

5) What regulation is needed for site management, including monitoring and verification, serious situations, and reporting?
6) What, if any, regulation is needed in respect of site closure?
7) What regulation is needed to manage transport?
8) What, if any, regulation is needed in respect of long term liability?
9) What, if any, regulation is needed in respect of performance bonds and guarantees?
10) What, if any, regulation is needed to manage interactions with the petroleum industry?
11) What, if any, regulation is needed to manage interactions with other users of the sea?
12) Who should be the regulator?

In November 2008, Australia passed the Offshore Petroleum Amendment (Greenhouse Gas Storage) Act, which establishes a national regime for the offshore capture and burial of carbon emissions.

As the CCS provisions form an amendment to Australia's key oil and gas legislation, the Offshore Petroleum Act 2006, there are three key features of that regime which must be understood. First, the Federal Government owns virtually all land containing minerals and petroleum. Secondly, the oil and gas regulation reflects Australia's federal system. The Offshore Petroleum Act at the Commonwealth level applies beyond State coastal waters (which are nominally within 3 nautical miles of the coast). Although this is Commonwealth legislation, it is administered by joint authority of the Commonwealth and State. The same regulations in each State apply to State coastal waters, with the aim that the same rules apply, regardless of jurisdiction. Separate State petroleum legislation applies in each state to the onshore area and islands. Finally, there are health, safety and environmental issues relating to the oil and gas industry that are dealt with under regulations made under the Act, and therefore CCS operators will also inherit that existing system.

The Greenhouse Gas Storage Act establishes access and property rights through a system of titles, which largely mirror the existing system of petroleum titles required for oil and gas exploration and production in the Commonwealth, including:

- a greenhouse gas assessment permit, which is similar to an exploration license;
- an injection license, which corresponds with a production license and authorizes injection and storage of greenhouse gas in an identified greenhouse gas storage formation; and
- other additional licenses: prospecting and access authorities, and infrastructure and pipeline licenses, holding lease licenses

In addition, the Act deals with two controversial issues: overlapping titles and long-term liability.

The Act generally gives primacy to the rights of the petroleum title holder through the "significant risk of a significant adverse impact" test. In terms of long-term liability, the Act provides for the transfer of long-term liability to the Commonwealth within 20 years of the completion of a storage project. The 20-year period gives the Minister five years to make a decision whether to grant a site closure certificate and a 15-year "assurance" period during which the Minister must be satisfied that the stored gas is behaving as expected.

Example 1: Onshore CCS in Victoria

The Victorian Parliament passed the Greenhouse Geological Sequestration Act in November 2008. The Victorian Act is a stand-alone Act and creates a regulatory regime for the conduct of CCS activities in onshore Victoria.

The Victorian Act establishes the processes by which CCS proponents will be permitted to obtain access and property rights to geological storage formations located in onshore Victoria.

An injection and monitoring license can only be surrendered if the Minister is satisfied that the stored gas is behaving in a predictable manner and has approved a monitoring and verification plan. The Victorian Act is silent on the issue of long-term liability for injected gases after the license has been surrendered.

Example 2: Onshore CCS in Queensland

The most recent state to introduce a regulatory regime for CCS activities is Queensland, with the passing in February 2009 of the Greenhouse Gas Storage Act.

The Queensland Act introduces a tenure regime to govern the discovery and use of underground reservoirs for the storage of carbon dioxide – the Act does not permit the sequestration of other greenhouse gases.

The key tenures to facilitate greenhouse gas storage are:

- a greenhouse gas exploration permit, which permits the exploration for underground geological structures suitable for injecting and storing greenhouse gas streams.
- a greenhouse gas injection and storage lease, for the actual injection, storage and monitoring of greenhouse gas streams.

The Queensland Act allows for the granting of greenhouse gas tenures over existing mining and petroleum tenures. Existing tenement holders have the right to lodge submissions in response to a greenhouse gas lease application, but ultimately the decision whether or not to grant the greenhouse gas tenure is at the discretion of the Minister.

A greenhouse gas lease will only be accepted for surrender when the risks associated with carbon storage have been reduced as much as possible. Ongoing monitoring is required. Ownership of carbon dioxide stored in underground reservoirs passes to the State upon surrender of a greenhouse gas lease; however, the Queensland Act does not explicitly state that liability is also transferred to the State at that point.

11.4 Partnerships

It appears likely that over the next 50 years, we will find our energy production moving substantially away from fossil fuels to greater use of renewable resources and nuclear resources. Our first response to issues of climate change has been to figure out where to put the GHG we produce. Next we have focused on how to reduce the amount emitted. Now we are turning our attention to reduction, storage and reuse.

The technology of carbon dioxide capture and storage has been the subject of substantial research for several decades now. Great progress has been made in understanding how to separate and capture GHG. Numerous demonstration projects and test wells have proceeded to understand the sequestration aspect. However, there have been questions raised as to whether storing the GHG underground is truly the best long term solution to the use of fossil fuels and whether we can realistically store the vast quantities that may be required. Importantly, we are beginning to see significant effort applied to the use and reuse of GHG.

Foremost in the discussion of potential partnerships in CCS development is the current use of EOR to store carbon dioxide while achieving a higher production of oil. This technology has been in use and an important part of the oil production industry in portions of the country for decades. It has resulted in over 4,000 miles of currently existing carbon dioxide pipelines, primarily in the Texas, Oklahoma and North Dakota oil fields. As an economic use for carbon dioxide, this alternative for storage will see increased use. However, it is unlikely that this technology will be able to manage more than a small percentage of the carbon dioxide that will be available for storage.

Interestingly, the dialogue surrounding GHG has begun to include the potential for beneficial use and reuse of the captured gases. One example is the language in recently passed legislation in Kentucky, HB 259 (Appendix 9) which states that "*Carbon dioxide has current and potential value and its geologic storage may allow for its orderly* *withdrawal as necessary for commercial, industrial, or other uses, including for enhanced oil and gas recovery."*

The NETL website highlights five approaches to the use/reuse of carbon dioxide including:

- Conversion of carbon dioxide as a feedstock to product chemicals, fuels and polymers;
- Non-geologic storage of carbon dioxide in stable solid materials which are either useful products or low cost materials;
- Indirect storage by increasing carbon intakes;
- Beneficial use of produced water from storage in saline formations; and
- Breakthrough concepts to limit emissions, increase consumption or produce useful products or fuels.

Breakthrough concepts include using carbon dioxide injection for enhancing methanol production, using carbon dioxide to make polycarbonates or other polymers, enhancing the rate of photosynthesis and increasing the net fixation of atmospheric carbon dioxide indirectly, enhancing geothermal systems that would facilitate carbon dioxide storage, and even genetic use of microbes that consume carbon dioxide and other ingredients and then produce methane.[38]

Innovative concepts for beneficial reuse of carbon dioxide funded by the DOE include[39]:

- SOIL REMEDIATION-Capturing and converting carbon dioxide into mineral carbonates to convert alkaline clay to carbonate-enhanced clay for soil remediation.

- BUILDING AGGREGATES AND CEMENTITIOUS SUBSTITUTES-Directly mineralizing carbon dioxide in flue gas to carbonates and converting them to materials directly usable in the construction industry, such as aggregates and cementitious substitutes.

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[38] http://www.netl.doe.gov/technologies/carbon_seq/core_rd/use-reuse.html
[39] http://fossil.energy.gov/recovery/projects/beneficial_reuse.html

- SALEABLE CARBONATE/BICARBONATE MATERIALS PRODUCTION-Removing carbon dioxide from industrial waste streams and generating saleable carbonate and/or bicarbonate materials.

- ALGAL OIL PRODUCTION-Capturing carbon dioxide gas and recycling it in an algal oil production process for various uses including food, fertilizers, chemicals, pharmaceuticals and fuel.

- METHANE PRODUCTION-Capturing carbon dioxide using macroalgae (seaweeds) and processing into methane.

- SYNGAS PRODUCTION-Processing carbon dioxide and natural gas in a solar reformer to produce syngas.

Developing technology that is the subject of intensive research is the use of algae to either strip carbon dioxide from flue gas or separate the gas and use it to feed massive growths of algae that will then be used to produce oil or gasified to produce electricity. Rather than sequestration, this technology results in a substantial and continual recycling of the carbon dioxide. The result, if successful, is the significant reduction of GHG released for each unit of energy produced. A discussion of this type of research currently conducted at the University of Kentucky Center for Applied Energy Research is found at http://www.caer.uky.edu/factsheets/biofuels_Fisk_Algae9-18-09.pdf. This is just one example of a significant effort in play across the country, and represents substantial engagement and funding by the DOE through their Carbon Sequestration initiative.

In addition to the above example, the DOE has recently provided substantial funding to various entities throughout the United States for continued research of the conversion of captured carbon dioxide emissions into useful products. Recent examples obtained from the DOE's fossil.energy.gov website include:

1. ALCOA, INC. (ALCOA CENTER, PA.) - Alcoa's pilot-scale process will demonstrate the high efficiency conversion of flue gas CO2 into soluble bicarbonate and carbonate using an in-duct scrubber system featuring an enzyme catalyst. The bicarbonate/carbonate scrubber blow down can be sequestered as solid mineral carbonates after reacting with alkaline clay, a by-product of aluminum refining. The carbonate product can be utilized as

construction fill material, soil amendments, and green fertilizer. Alcoa will demonstrate and optimize the process at their Point Comfort, Texas aluminum refining plant. (DOE Share: $11,999,359)

2. NOVOMER INC. (ITHACA, N.Y.) - Teaming with Albemarle Corporation and the Eastman Kodak Co., Novomer will develop a process for converting waste CO2 into a number of polycarbonate products (plastics) for use in the packaging industry. Novomer's novel catalyst technology enables CO2 to react with petrochemical epoxides to create a family of thermoplastic polymers that are up to 50 percent by weight CO2. The project has the potential to convert CO2 from an industrial waste stream into a lasting material that can be used in the manufacture of bottles, films, laminates, coatings on food and beverage cans, and in other wood and metal surface applications. Novomer has secured site commitments in Rochester, NY, Baton Rouge, Louisiana, and Orangeburg, SC where Phase 2 work will be performed. (DOE Share: $18,417,989)

3. TOUCHSTONE RESEARCH LABORATORY LTD. (TRIADELPHIA, W. VA.) - This project will pilot-test an open-pond algae production technology that can capture at least 60 percent of flue gas CO2 from an industrial coal-fired source to produce biofuel and other high value co-products. A novel phase change material incorporated in Touchstone's technology will cover the algae pond surface to regulate daily temperature, reduce evaporation, and control the infiltration of invasive species. Lipids extracted from harvested algae will be converted to a bio-fuel, and an anaerobic digestion process will be developed and tested for converting residual biomass into methane. The host site for the pilot project is Cedar Lane Farms in Wooster, Ohio. (DOE Share: $6,239,542)

4. PHYCAL, LLC (HIGHLAND HEIGHTS, OHIO) - Phycal will complete development of an integrated system designed to produce liquid biocrude fuel from microalgae cultivated with captured CO2. The algal biocrude can be blended with other fuels for power generation or processed into a variety of renewable drop-in replacement fuels such as jet fuel and biodiesel. Phycal will design, build, and operate a CO2-to-algae-to-biofuels facility at a nominal thirty acre site in Central O'ahu (near Wahiawa and Kapolei), Hawaii. Hawaii Electric Company will qualify the biocrude for boiler use, and Tesoro will supply CO2 and evaluate fuel products. (DOE Share: $24,243,509)

5. SKYONIC CORPORATION (AUSTIN, TEXAS) - Skyonic Corporation will continue the development of SkyMine® mineralization technology--a potential replacement for existing scrubber technology. The SkyMine process transforms CO2 into solid carbonate and/or bicarbonate materials while also removing sulfur

oxides, nitrogen dioxide, mercury and other heavy metals from flue gas streams of industrial processes. Solid carbonates are ideal for long-term, safe aboveground storage without pipelines, subterranean injection, or concern about CO2 re-release to the atmosphere. The project team plans to process CO2-laden flue gas from a Capital Aggregates, Ltd. cement manufacturing plant in San Antonio, Texas. (DOE Share: $25,000,000)

6. CALERA CORPORATION (LOS GATOS, CALIF.) - Calera Corporation is developing a process that directly mineralizes CO2 in flue gas to carbonates that can be converted into useful construction materials. An existing CO2 absorption facility for the project is operational at Moss Landing, Calif., for capture and mineralization. The project team will complete the detailed design, construction, and operation of a building material production system that at smaller scales has produced carbonate-containing aggregates suitable as construction fill or partial feedstock for use at cement production facilities. The building material production system will ultimately be integrated with the absorption facility to demonstrate viable process operation at a significant scale. (DOE Share: $19,895,553)" [39]

This fairly new emphasis on the reuse and recycling of carbon dioxide and increase in energy intensity for each unit of GHG emitted appears to be the most promising approach to supplement carbon dioxide sequestration.

11.5 Recent Developments in Kentucky

The Kentucky Legislature completed its regular 2011 session. Two bills pertaining to carbon dioxide transportation and sequestration have been passed and, as of March 15, 2011, one has been signed and the other remains awaiting signature by the Governor. These bills, HB 259 and SB 50, are provided in **Appendix 9**.

HB 259 applies to demonstration projects for carbon sequestration. The bill states that the pore space is assumed to belong to the surface owners unless explicitly severed. The bill also allows for the transfer of ownership and long term liability to the federal or state government following successful completion of post closure permit requirements. There is no provision for prior funding of the long term liability. HB 259 was signed on March 15, 2011.

SB 50 provides eminent domain powers to construct carbon dioxide pipelines in Kentucky and remains to be signed by the Governor.

12.0 RECOMMENDATIONS

The research conducted for this Task clearly indicates that the development of a CTL industry has many hurdles to overcome. Observation of world events, filtered by the information developed for this Task, drives toward a conclusion that development of the CTL industry is important for our national security. In order to provide adequate liquid fuels for industry, manufacturing, transportation, heating and security, and to provide those fuels at stable prices, we will need to find and develop new sources for these varying fuels.

Because there is no existing CTL industry at this time, our estimates of the time and effort required to site, design, permit, and construct a facility are educated estimates, based on experience in complex energy development projects and are expected to be supported by practice as the industry develops.

Following are areas identified by the research that hold potential for improving the process of siting, permitting and developing a successful CTL project.

Coordinated Permitting Effort

One clear conclusion from the research is that there is virtually no coordination between the numerous permitting efforts. While certain sets of information may be used for several permit programs, e.g. cultural and historic research will be required for several permitting programs, there is a large duplication of efforts. Streamlining the permitting process could reduce the time and cost to the developer while retaining protection of the environment and the surrounding community. Successful integration will require coordination between local, state and federal agencies.

Impact of Uncertainty

Uncertainty is present in many aspects of developing a coal-to-liquids facility at this point. The technology is not new although improvements are always being made. Additional changes in technology will be a result of regulatory requirements, whether as the result of federal legislation or EPA regulatory action.

Regulatory requirements resulting from GHG concerns are taking shape but may be changed as the result of legislation or litigation.

The real cost and likelihood of long term liability from carbon dioxide storage or sequestration remains to be discovered. Consistent throughout the research and review of pending or passed legislation is a need to establish a means of managing that long term liability, whatever it turns out to be. At this point, states are trying to tackle this issue on their own. It may be reasonable and advisable for the federal government to step into that void. Adopting a federal program which serves as a backup to commercially available insurance appears to be the best approach and would, among other things, serve to simplify liability issues for sequestration sites that cross state boundaries.

Need to Stay Current

The technology, legislative and regulatory fields reviewed and investigated for this report are in flux and will continue to be for some time. Aspects of this report are designed to be active tools to be used by project developers. To remain valuable, they will need to be updated regularly.

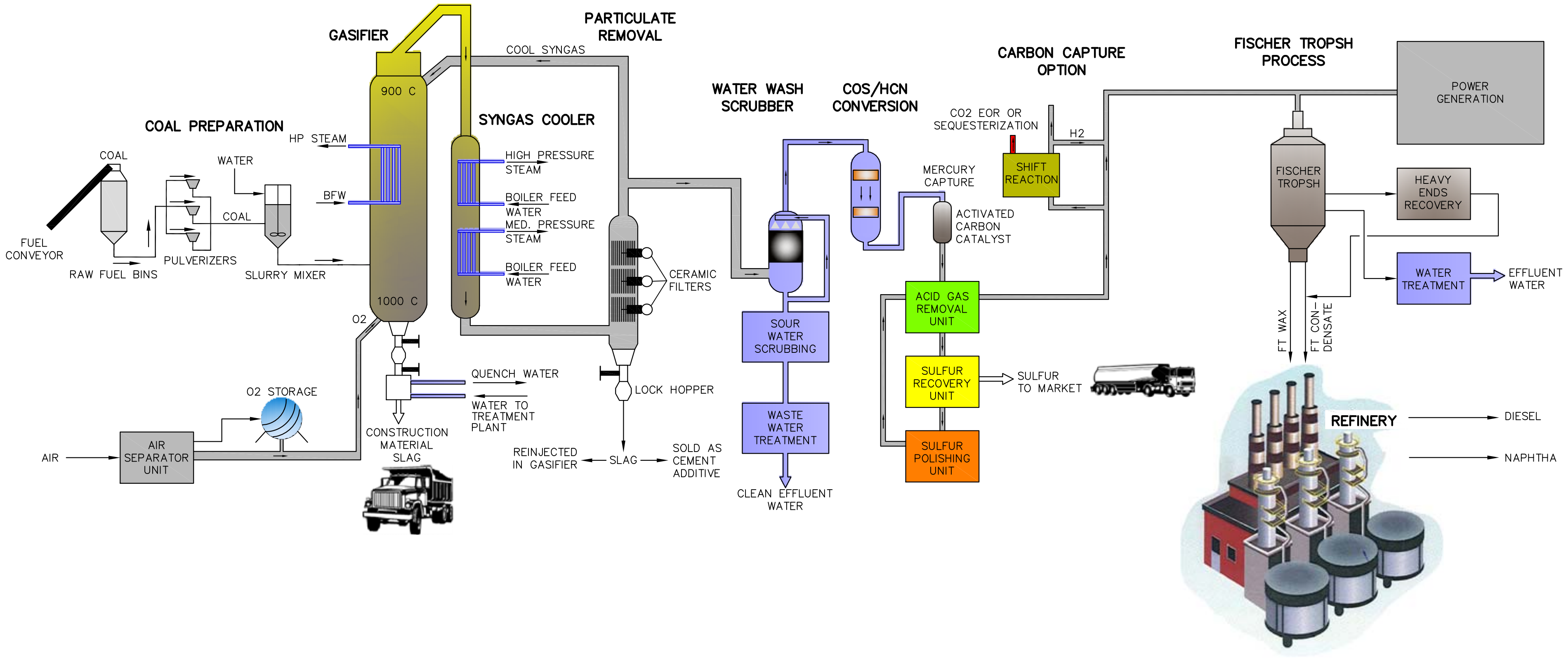
In addition, it appears that much of the information developed should be accessible electronically and through web access. For example, the Permit Map is designed to be accessed electronically with links to appropriate publically available information and guidance. As regulatory requirements change, those references should be updated.

The listing of contacts within each state appears to be a unique juxtaposition of information. It is suggested that this listing be made available on line with frequent updates and the contacts identified within each state will change with changes in administration and policy. It does appear that this basic entry information would be useful to developers in the early stages of identifying appropriate locations for projects either of CTL facilities, transportation infrastructure or sequestration potential. Certainly, this entry information can be limited to those states where access to coal is likely.

Continuation of Research Efforts

The evaluation of a site for sequestration potential highlights the importance of continued research of the potential for storage capacity. In order to make commercially viable decisions, a developer must have access to accurate information with regard to the potential for sequestration at or near the development site. Currently, much of any determination relies on assumptions and extrapolation of available data. Additional research and data is recommended to enable more accurate predictions of success.

Because capacity limitations are expected with geologic storage, research efforts and commercial demonstration of potential reuse or recycling of GHG is essential. Development of creative methodologies to capture and use carbon dioxide beneficially has the potential to substantially mitigate greenhouse gas emissions and is therefore an essential part of the successful implementation of coals-to-liquids technology in the current political climate.



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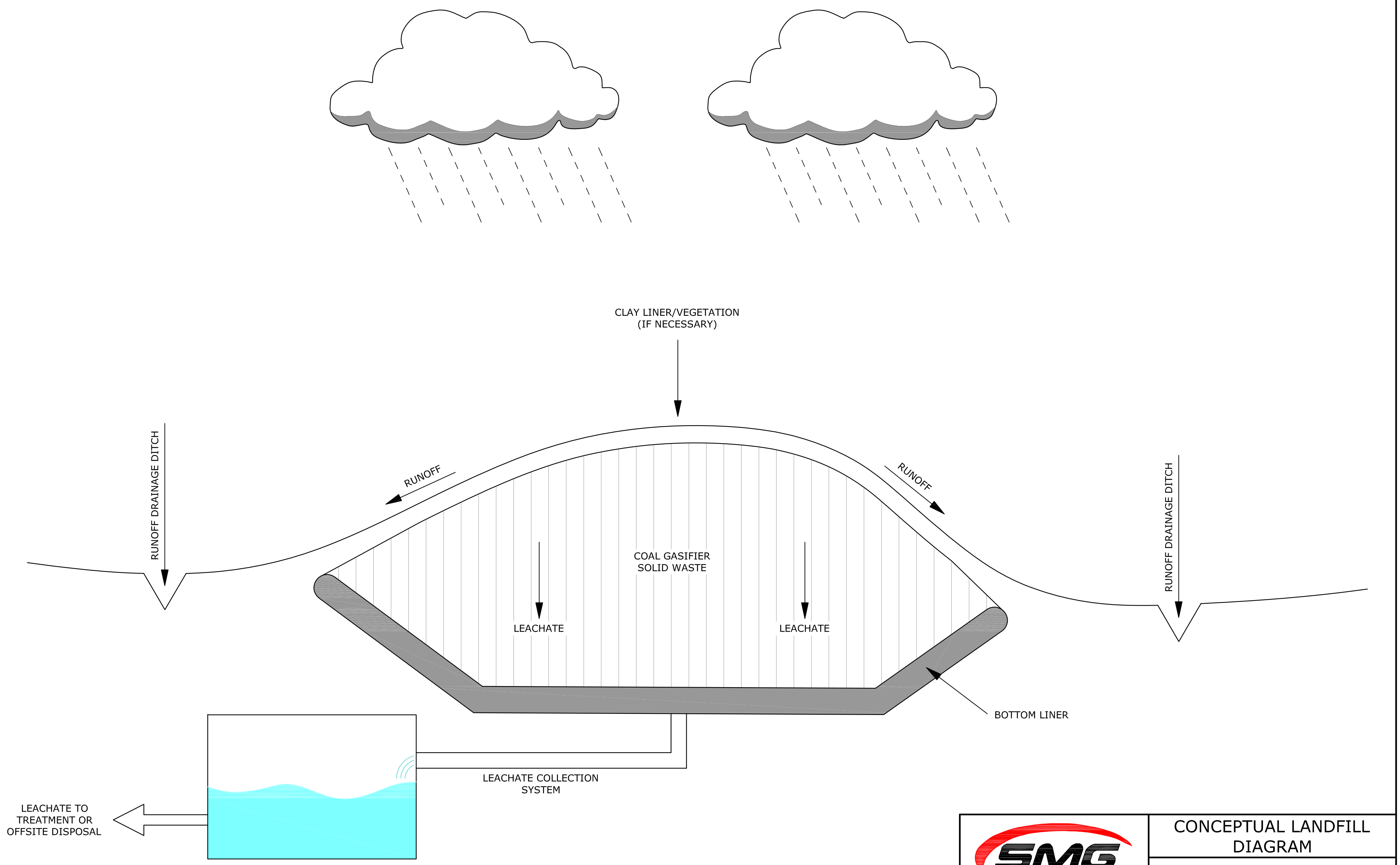
CONCEPTUAL CTL PROCESS

PREPARED FOR
VSE CORPORATION

SCALE: NTS
DATE: 3/8/10
PREPARED BY: KAF
CHECKED BY: CTW

JOB NO.
2009-4626

FIGURE
1



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CONCEPTUAL LANDFILL DIAGRAM

PREPARED FOR
VSE CORPORATION

SCALE: NTS
DATE: 3/16/10
PREPARED BY: KAF
CHECKED BY: CTW

JOB NO.
2009-4626

FIGURE
2

APPENDIX 1
Acronyms, Abbreviations, and Nomenclature

ACRONYMS, ABBREVIATIONS AND NOMENCLATURE

A/E	Architect/engineer
acfm	Actual cubic feet per minute
AACE	Association for the Advancement of Cost Engineering
AFBC	Atmospheric fluidized-bed combustors
AFDC	Allowance for funds used during construction
AGR	Acid gas removal
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ASU	Air Separation Unit
ATS	Advanced turbine system
BACT	Best available control technology
Bbl	barrels
Bbl/day	barrels per day
BTL	Biomass-to-liquids
Btu	British Thermal Unit
CAAA	Clean Air Act Amendments of 1990
CCPI	Clean Coal Power Initiative
CCT	Clean coal technology
CDR	Carbon Dioxide Recovery
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CGE	Cold gas efficiency
CHAT	Cascaded humidified advanced turbine
CF	Capacity factor
CO2	Carbon dioxide
COE	cost of electricity
COS	Carbonyl sulfide
CPFBC	Circulating pressurized fluidized-bed combustors
CRT	Cathode ray tube
CS	Carbon steel
CT	Combustion turbine
CTG	Coal-to-gasoline
CTL	Coal-to-liquids
CWT	Cold water temperature
dB	Decibel
DCS	Distributed control system
DLN	Dry low NOx
DME	Dimethylether
DOD	US Department of Defense
DOE	US Department of Energy
EA	Environmental Assessment
EIS	Environmental Impact Statement
E-GasTM	Global Energy (now ConocoPhillips) gasifier technology
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
ETA	Effective thermal efficiency

ETBE	Ethyl tert butyl ether
FBHE	Fluidized-bed heat exchanger
FD	Forced draft
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FOAK	First of a kind
FRP	Fiberglass-reinforced plastic
F-T	Fischer-Tropsch Process
GJ	Gigajoule
gpm	Gallons per minute
GSP	Gasifier according to Gaskombinat Schwarze Pumpe
GT	Gas turbine
GTL	Gas-to-liquids
h, hr	Hour
H_2	Hydrogen
H_2SO_4	Sulfuric acid
HAP	Hazardous air pollutant
HCl	Hydrochloric acid
HDPE	High density polyethylene
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HTFT	High-temperature Fischer-Tropsch
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
in.	H2O Inches water
in.	Hga Inches mercury (absolute pressure)
in. W.C.	Inches water column
ID	Induced draft
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gasification Combined Cycle Power Plant
IOU	Investor-owned utility
IP	Intermediate pressure
IPP	Independent power producer
IRP	Integrated resource planning
ISO	International Standards Organization
ITM	Ion transfer membrane
kPa	Kilopascal absolute
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
kWt	Kilowatts thermal
LAER	Lowest achievable emission rate
lb	Pound
LCOE	Levelized cost of electricity
LASH	Limestone ash
LEBS	Low emissions boiler systems
LGTI	Louisiana Gasification Technology Inc.

LHV	Lower heating value
LP	Low pressure
LPG	Liquefied Petroleum Gas (mostly commercial propane and commercial butane)
LTFT	Low Temperature Fischer-Tropsch
MC	Mitigation cost
MAF	Moisture and Ash Free
MCR	Maximum coal burning rate
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MHz	Megahertz
MMBtu	Million British thermal units (also shown as 106 Btu)
MMBtuh	Million British thermal units (also shown as 106 Btu) per hour
MOGD	Mobil Olefin to Gasoline/Distillate
MPa	Megapascals absolute
MTBE	Methyl tert-butyl ether
MTG	Methanol-to-gasoline
MTO	Methanol-to-olefins
MTPA	Metric tons per year
MTS	Methanol-to-synfuels
MWe	Megawatts electric
MWh	Megawatts-hour
MWt	Megawatts thermal
NETL	National Energy Technology Laboratory
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NGCC	Natural gas combined cycle
NM3	Normal Cubic meter
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
O&M	Operations and maintenance
OD	Outside diameter
OP/VWO	Over pressure/valve wide open
OTR	Ozone transport region
PA	Primary air
PC	Pulverized coal
pph	Pounds per hour
ppmvd	Parts per million volume, dry
PRENFLO	Pressurized Entrained-flow Gasification Process (Uhde)
PSA	Pressure Swing Adsorption
psia	Pounds per square inch absolute
psid	Pounds per square inch differential
psig	Pounds per square inch gage
QF	Qualifying facility
RDS	Research Development Solutions, LLC
RON	Research Octane Number
RPD	Restricted pipe discharge
rpm	Revolutions per minute
SAS	Sasol Advanced Synthol
SC	Supercritical
SCFD	Standard cubic feet per day

scfm	Standard cubic feet per minute
SCGS	Shell Coal Gasification Process
scmh	Standard cubic meter per hour
SCOT	Shell Claus Off-gas Treating
SCR	Selective catalytic reduction
SGP	Shell Gasification Process
SIP	State implementation plan
SNCR	Selective non-catalytic reduction
SO2	Sulfur dioxide
SOFC	Solid oxide fuel cell
SS	Stainless steel
SSPD	Sasol’s Proprietary Slurry-phase Distillate
stpd	Short tonnes per day
TAG	Technical Assessment Guide
ST	Steam turbine
TCR	Total capital requirement
TGTU	Tail gas treating unit
TIGAS	Topsoe Integrated Gasoline Synthesis
TPC	Total plant capital (cost)
THGD	Transport hot gas desulfurizer
TPC	Total plant cost
tpd	Tons per day
tph	Tons per hour
TPI	Total plant investment
V-L	Vapor Liquid portion of stream (excluding solids)
WB	Wet bulb
wt%	Weight percent

APPENDIX 2
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APPENDIX 3
Permit List

ENVIRONMENTAL PERMIT AND APPROVAL SUMMARY

CATEGORY	AUTHORITY	PERMIT OR APPROVAL	AGENCY	DIVISION	ACTIVITY
Site Planning and Development	Federal	*Determination of No Significant Environmental Impact under the National Environmental Policy Act (NEPA)*	U.S. Environmental Protection Agency (EPA)		Federal funded or approved projects that may impact environmental resources
Site Planning and Development	Federal	*No Adverse Impact to Endangered Species*	U.S. Fish and Wildlife Service		Determination of potential impacts to endangered species and their habitat
Site Planning and Development	Federal	*Stack Height Obstruction Determination*	Federal Aviation Administration		Determination of potential hazard to air navigation by stack structures
Site Planning and Development	State	*Stack Height Obstruction Determination*	Kentucky Airport Zoning Commission		Determination of potential hazard to air navigation by stack structures
Site Planning and Development	State	*Cultural and Historic Preservation*	Kentucky Commerce Cabinet	Kentucky Heritage Council	Site construction or disturbance that may impact cultural and historic resources
Site Planning and Development	State	*Building Permit*	Kentucky Department of Housing, Buildings, and Construction	Division of Building Code Enforcement	Construction plan review and approval
Site Planning and Development	Local	*Construct industrial facility*	Local Planning Commission or Zoning Board		Obtain zoning change and determination that facility meets approved land use
Air	State	*Air Emissions Permit for Major Sources under Title V of the Clean Air Act Amendments*	Kentucky Department of Environmental Protection (KDEP)	Division for Air Quality (DAQ)	Construction and operation of a source of air emissions that exceed Title V major source thresholds
Air	Federal	*Title V Air Emissions Permit*	EPA		Federal review of Kentucky Title V air quality permit
Air	State	*State Origin Air Permit*	KDEP	DAQ	Construction and operation of a source of air emissions that exceed Kentucky thresholds (and are below Title V major source thresholds)
Air	Federal	*GHG Monitoring and Reporting*	EPA		Requirement to monitor and report greenhouse gas emissions
Waste	State	*On Site Special Waste Permit*	KDEP	Division of Waste Management (DWM)	Disposal of gasifier slag on site in a designed landfill
Waste	State	*Hazardous Waste Generator Registration*	KDEP	DWM	Management of hazardous wastes on site
Waste	State	*Hazardous Waste Landfill Permit*	KDEP	DWM	Disposal of hazardous waste onsite
Waste	Local	*Off Site Solid Waste Disposal Approval*	Private solid waste management company or local municipality operating disposal facility		Approval for disposal of industrial solid wastes (not hazardous) off site
Water	Federal	*Section 10 of the Rivers and Harbors Act Construction in Navigable Waters Permit -- Barge Unloading and Water Withdrawal*	U.S. Army Corps of Engineers (USACE)		Construction of dock for barge unloading and structures supporting water withdrawal
Water	Federal	*Section 404 of the Clean Water Act Permit for Dredge and Fill of U.S. Waters*	USACE and EPA		Discharge of dredged or fill material into waters of the U.S.
Water	State	*Floodplain Construction Permit*	KDEP	Division of Water (DoW) -- Floodplain Management Section	Construction within the 100-year floodplain of any Kentucky stream
Water	State	*Section 401 Water Quality Certification*	KDEP	DoW -- Floodplain Management Section	Construction activities affecting Kentucky waters that may impact water quality
Water	State	*General Stormwater Permit for Construction Activities*	KDEP	DoW	Stormwater associated with construction activities that is discharged to waters of Kentucky
Water	State	*Kentucky Pollution Discharge Elimination System (KPDES) Permit*	KDEP	DoW	Point source discharges of wastewater (other than stormwater) to waters of Kentucky
Water	State	*Construction Permit for Sewer Line Extension*	KDEP	DoW	Access to local Publically Owned Treatment Works for wastewater treatment
Water	State	*Water Withdrawal Permit*	KDEP	DoW	Withdrawal of greater than 10,000 gallons per day of Kentucky water resources
Water	State	*Potable Water Supply Permit*	KDEP	DoW, Local Health Department	Operating a drinking water treatment and distribution system
Water	Local	*Sanitary Sewer Connection Approval*	Local Municipality		Access and utilization of local sanitary sewage treatment plant
Water	Local	*Potable Water Access*	Local Municipality		Access and use of public drinking water supply

ENVIRONMENTAL PERMIT AND APPROVAL SUMMARY

CATEGORY	AUTHORITY	PERMIT OR APPROVAL	AGENCY	DIVISION	ACTIVITY
Electric Service, Generation and Transmission	State	*Kentucky Generation and Transmission Electric Siting Board Approval*	Kentucky Public Service Commission	Kentucky Siting Board	Approval for construction of merchant electric generating facilities and electric transmission lines not regulated by the state Public Service Commission
Electric Service, Generation and Transmission	Local	*Electric Utility Approval*	Local Power Company		Access and utilization of local power grid
Electric Service, Generation and Transmission	Local	*Regional Transmission Organization (RTO) Approval*	Regional or Independent Transmission Organization		Approval to use regional electric transmission grid for the sale of electricity
Hazardous and Toxic Material Management	State	*License to Install Product Storage Tanks*	Kentucky Department of Housing, Buildings, and Construction	Hazardous Materials Section	Installation of above ground and underground storage tanks
Hazardous and Toxic Material Management		*TSCA Chemical Manufacturing and Reporting*			

APPENDIX 4
Energy Contacts

STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
Alaska	**Michael Harper, Deputy Director** Alaska Energy Authority Email: mharper@aidea.org Phone: 907-771-3000 813 West Northern Lights Blvd. Anchorage, AK 99503	http://www.akenergyauthority.org/	Alaska Energy Authority (AEA) projects and programs provide for the operation and maintenance of existing Authority-owned projects with maximum utility control; and assists in the development of safe, reliable, and efficient energy systems throughout Alaska reducing the cost of electricity for residential customers and community facilities in rural Alaska	**Michael Harper, Deputy Director** Alaska Energy Authority Email: mharper@aidea.org Phone: 907-771-3000 813 West Northern Lights Blvd. Anchorage, AK 99503	http://www.akenergyauthority.org/	AEA is the vested with assisting construction, acquisition, financial, and operational issues related to power projects and facilities. AEA will not issue the appropriate environmental permits but can provide information and contact information with each state agency.
				James R. Hemsath, Deputy Director - Business Development Alaska Industrial Development and Export Authority Alaska Energy Authority Email: jhemsath@aidea.org Phone: 907-771-3040 813 West Northern Lights Blvd. Anchorage, AK 99503	http://www.akenergyauthority.org/	
Alabama	**Terri Adams, Energy Division Director** Alabama Department of Economic and Community Affairs Phone: 334-242-5292 Email: terri.adams@adeca.alabama.gov	http://www.adeca.alabama.gov/Energy/default.aspx	The Energy Division provides assistance and services to the citizens of our state through the management and development of energy programs, and fosters the advancement of technology to strengthen the Alabama economy.	**Russell Kelly, Chief** Permits and Services Division ADEM 334-271-7715 1400 Coliseum Blvd. Montgomery, AL 36109	http://www.adem.state.al.us/	The Energy Division is the proper authority for financial assistance and initial development of an energy project. The ADEM is responsible to enforce rules and regulations consistent with approved permits.
Arkansas	**Chris Benson, Director** Arkansas Energy Office Email: cbenson@arkansasedc.com Phone: 501-682-1370 One Capitol Mall Little Rock, Arkansas 72201	http://arkansasenergy.org/	The Arkansas Energy Office is a division of the Arkansas Economic Development Commission. The Energy Office promotes energy efficiency and emerging technologies through energy education and information programs as well as managing federal energy funds in the State of Arkansas.			The Arkansas Energy Office is responsible for the management of new energy projects and funneling federal energy funds.
	Clint O'Neal Business Development Arkansas Economic Development Commission Email: COneal@ArkansasEDC.com Phone: 501-682-2563 One Capitol Mall Little Rock, AR 72201	http://arkansasedc.com/	The ADEC mission is to lead statewide economic development, create targeted strategies which produce better paying jobs, promote communities, and support the training and growth of a 21st century skilled workforce.			ADEC is responsible for developing strategies to promote new projects in Arkansas and create a workforce for those projects.
Arizona	**Jim Arwood, Director** Arizona Department of Commerce Email: jima@azcommerce.com Phone: 602-771-1100 1700 W. Washington, Suite 600 Phoenix, Arizona 85007	http://new.azcommerce.com/Energy/	The AZ Department of Commerce's mission is to provide leadership and collaborative partnerships to create vibrant communities and a globally competitive Arizona economy			The AZ Department of Commerce encourages and provides energy information and policy advice for new energy projects. The Department of Commerce will serve as the general contact and provide information and contact information for other state agencies.
California	**Terry O'Brien, Deputy Director** California Energy Commission Siting, Transmission and Env. Protection Email: tobrien@energy.state.ca.us Phone: 916-654-3924 1516 Ninth Street, MS-29 Sacramento, CA 95814	http://www.energy.ca.gov/	The California Energy Commission is the state's primary energy policy and planning agency. The Commission supports public interest energy research that advances energy science and technology through research, development, and demonstration programs.			The CEC is responsible for the funding and planning of any new energy project. The Commission will also serve as the general contact and provide contact for environmental permitting.

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STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
	Eillen Allen, Siting and Compliance Office Siting, Transmission and Env. Protection Email: eallen@energy.state.ca.us Phone: 916-654-4082 1516 Ninth Street, MS-29 Sacramento, CA 95814	http://www.energy.ca.gov/				
Colorado	**Tom Plant, Director** Governor's Energy Office Email: tom.plant@state.co.us Phone: 303-866-2202 1580 Logan Street, Suite 100 Denver, Colorado 80203	www.colorado.gov/energy	The GEO's mission is to lead Colorado to a New Energy Economy by advancing energy efficiency and renewable, clean energy resources.	**Tom Plant, Director** Governor's Energy Office Email: tom.plant@state.co.us Phone: 303-866-2202 1580 Logan Street, Suite 100 Denver, Colorado 80203	www.colorado.gov/energy	The GEO works with private organizations to promote energy efficient technologies. The GEO does not issue permits but can provide information for funding and other contacts within state government.
Connecticut	**Raymond Wilson, Director** Policy Development and Planning Division Email: raymond.wilson@ct.gov Phone: 860-418-6416 450 Capitol Avenue Hartford, CT 06106-1379	http://www.ct.gov/opm/site/default.asp	One critical role of OPM is that of coordinator/leader of interagency problem solving efforts. Most significant policy issues faced by the State involve the overlapping jurisdiction of more than one State agency, and encompass a range of programmatic, budgetary, and policy concerns. OPM is often called upon to lead, convene or facilitate multi-agency efforts to address these problems.			OPM reports directly to the Governor, providing information required to form policy decisions. OPM will serve as the general contact and provide information and contact information for each state agency. Through email and phone correspondence it was determined Connecticut does not have an official energy development contact. All state contacts referred to the listed DOE Energy Efficiency and Renewable Energy website contact.
Delaware	**Charlie T. Smisson, Jr., State Energy Coordinator** Delaware Energy Office Email: charlie.smisson@state.de.us Phone: 302-735-3480 1203 College Park Drive, Suite 101 Dover, DE 19904	http://www.dnrec.delaware.gov/energy	The Governor's Energy Advisory Council is charged with spearheading a Delaware Energy Plan, which is updated every five years. The new plan is to be completed by the spring of 2009.			The DNREC administers the state energy program and serves as the contact for private organizations and state agency energy issues. DMTEC will serve as the general contact and provide information and contact information for each state agency.
Florida	**Jeremy Susac, Director** Florida Energy Office Email: jeremy.susac@eog.myflorida.com Phone: 850-487-3800 3900 Commonwealth Boulevard M.S. 49 Tallahassee, Florida 32399	http://www.dep.state.fl.us/energy/	Through the Florida Energy Office, the State of Florida shapes “Florida’s Energy Future,” focusing on advanced clean energy sources, energy conservation and efficiency. Florida is actively leading the nation in projects that promote hydrogen power, solar energy, bioenergy, biofuels, clean vehicles and energy conservation.			The Florida DEP will provide the appropriate environmental permits for a CTL facility. The DEP also provides policy advice for new energy projects and will serve as the general contact for the development of a CTL facility.
	Mike Halpin, Siting Administrator Site Coordination Office Mike.Halpin@dep.state.fl.us 850-245-8002 2600 Blair Stone Rd, MS 48 Tallahassee, FL 32399	http://www.dep.state.fl.us/siting/				
Georgia	**Jill P. Stuckey, Director** GEFA-Center of Innovation for Energy Email: jill@gefa.ga.gov Phone: 404-584-1041 233 Peachtree Street NE Harris Tower, Ste 900 Atlanta, GA 30303	http://energy.georgiainnovation.org	The Center provides strong leadership and guidance for energy industry. With a business-oriented focus, the Center of Innovation for Energy supports the expansion, production and use of renewable energy and bio-fuels.			The Center provides leadership and guidance for energy projects that draw on the state's resources. The Center will serve as the general contact and direct a developer to the proper contacts within each state agency.
	J. David Dunagan, Renewable Energy Program Manager GEFA-Center of Innovation for Energy Email: jdavid@gefa.ga.gov Phone: 404-584-1105 233 Peachtree Street NE Harris Towner, Ste 900 Atlanta, GA 30303	http://energy.georgiainnovation.org				

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STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
Hawaii	**Joshua B.Y. Strickler** Facilitator of Renewable Energy Projects Email: Joshua.B.Strickler@dbedt.hawaii.gov Phone: 808-587-3837 235 S. Beretania St. 5th Floor Honolulu, HI 96813	http://www.hawaii.gov/dbedt/info/energy	The Department of Business, Economic Development & Tourism is Hawaii's resource center for economic and statistical data, business development opportunities, energy and conservation information, and foreign trade advantages.			The Department of Business, Economic Development & Tourism reports directly to the Governor providing information required to form policy decisions. The Department will serve as the general contact and provide information and contact information for the development of a new energy project.
Idaho	**Lane Packwood, Administrator** Economic Development Idaho Department of Commerce Phone: 208-334-2650 x2134 700 West State St. Boise, ID 83702	www.commerce.idaho.gov	The Commercial Innovation Division of the Idaho Department of Commerce is the state's only state office focusing solely on the development of Idaho's innovation industry and the application of technology to all Idaho businesses. The Commercial Innovation staff sets goals for innovation industry development in the state and supports the establishment, expansion, and attraction of technology companies, builds partnerships and programs, fosters infrastructure and research, and develops the state's technology image nationally and internationally.			The Department of Commerce works with private organizations to promote energy innovations. The Department of Commerce does not issue permits but can provide information for funding and other contacts within state government.
	Lisa La Bolle, Director of Energy Policy Idaho Office of Energy Resources Phone: (208) 287-4993 Email: Lisa.LaBolle@oer.idaho.gov 322 East Front Street Boise, Idaho 83720-0098	www.energy.idaho.gov	The Office of Energy Resources has the responsibility for energy planning, policy and coordination in the State of Idaho.			The Office of Energy Resource reports to the Governor providing information required to form policy decisions. This Office will not provide required permits but can direct a developer to contacts within each proper state agency.
Iowa	**Sherry Timmins, Regulatory Assistance Coord.** Iowa Department of Economic Development Email: sherry.timmins@iowalifechanging.com Phone: 515-242-4901 200 East Grand Avenue Des Moines, IA 50309	www.iowalifechanging.com	The Iowa Department of Economic Development mission is to engender and promote economic development policies and practices which stimulate and sustain Iowa's economic growth and climate and that integrate efforts across public and private sectors.			The Iowa Department of Economic Development provides a one-stop shop for business contacts to develop ideas and will work with the developer to develop the business.
	Tommi Makila, Senior Energy Policy Analyst Iowa Department of Natural Resources/Energy Independence Email: tommi.makila@dnr.iowa.gov Phone: 515-281-3142 502 E. 9th Street Des Moines, IA 50319	www.iowadnr.com/	The Iowa Department of Natural Resources is the government agency that leads Iowans in caring for their natural resources. It is responsible for maintaining state parks and forests, protecting the environment, and managing energy, fish, wildlife, and land and water resources in Iowa.			The Iowa DNR will provide the proper environmental review and permits for an energy project.
Illinois	**Jonathan Feipel, Energy Division Manager** Illinois Department of Commerce and Economic Opportunity Email: Jonathan.Feipel@illinois.gov Phone: 217-785-3416 620 East Adams Street Springfield, Illinois 62701	http://www.commerce.state.il.us	The Department of Commerce & Economic Opportunity (DCEO) is the lead state agency responsible for improving Illinois' competitiveness in the global economy. Guided by an innovative regional approach, DCEO administers a wide range of economic and workforce development programs, services and initiatives designed to create and retain high quality jobs and build strong communities.	**Bill Hoback** Bureau Chief Department of Commerce and Eco. Opportunity Coal Development & Marketing Email: bill.hoback@illinois.gov Phone: 217-782-6370 620 East Adams Street Springfield, IL 62701	http://www.commerce.state.il.us/dceo/	The Illinois Department of Commerce can provide a one-stop shop for business contacts to develop energy ideas and will work with the developer to develop the energy facility.

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STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
Indiana	**Brandon Seitz, Manager** Office of Energy Development Email: bseitz@oed.in.gov Phone: 317-232-8939 101 W. Ohio Street, Ste 1250 Indianapolis, IN 46204	http://www.in.gov/oed/	The Indiana Office of Energy & Defense Development (OED) was established to shepherd the state's energy plan. Realizing that sound energy policy has a significant impact on economic development, OED guides efforts to find homegrown energy solutions for our nation's armed forces, as well as assisting and promoting economic development in Indiana in the defense and energy industries.	**Marty Irwin, Director** Center for Coal Technology Research Email: mwirwin@purdue.edu Phone: 765-494-7414 Potter Engineering Building 500 Central Dr Purdue University West Lafayette IN 47907	http://www.purdue.edu/	The Center for Coal Technology Research (CCTR) is an Indiana state agency located at Purdue University's Energy Center at Discovery Park. The legislated objective of the CCTR is to promote the use of Indiana's coal reserves in an economically and environmentally sound manner.
Kansas	**Ray Hammarlund, Director Kansas Energy Office** Kansas Corporation Commission Email: r.hammarlund@kcc.ks.gov Phone: 785-271-3170 1300 SW Arrowhead Road, Suite 100 Topeka, KS 66604	http://www.kcc.ks.gov/energy/index.htm	The mission of the state corporation commission is to protect the public interest through impartial, and efficient resolution of all jurisdictional issues. The agency shall regulate rates, service and safety of public utilities, common carriers, motor carriers, and regulate oil and gas production by protecting correlative rights and environmental resources.			The Kansas Corporation Commission was established to provide easy-access information to the citizens of Kansas. This agency will act as a on-stop shop for a developer to develop an energy project.
Kentucky	**Dr. Leonard Peters, Secretary** Department for Energy Development & Independence len.peters@ky.gov Phone: 502-564-7192 500 Mero St., 12th Floor Capital Plaza Tower Frankfort, KY 40601	http://www.energy.ky.gov/	The Department for Energy Development and Independence is to develop clean, reliable, affordable energy sources that help us improve our energy security, reduce our carbon dioxide emissions and provide economic prosperity.	**Don Newell** Department for Energy Development & Independence Division of Transportation Energy Supply and Distribution Email: Donald.Newell@ky.gov Phone: 502-564-7192 500 Mero Street, 12th Floor, Capital Plaza Tower Frankfort, KY 40601	http://www.energy.ky.gov/	The Kentucky DEDI was established within the Energy and Environment Cabinet to help develop KY energy resources. This agency can act as a general contact and provide specific contact within each appropriate state agency.
				Rodney Andrews, Director Center for Applied Energy Research Email: andrews@caer.uky.edu Phone: 859-257-0200 2540 Research Park Drive Lexington, KY 40511	http://www.caer.uky.edu/	The University of Kentucky Center for Applied Energy (CAER) investigates energy technologies to improve the environment. CAER's mission is to excel as an applied research and development center with an international reputation, focusing on the optimal use of Kentucky's and the nation's energy resources for the benefit of its people
Louisiana	**Dane Revette, Director** Energy Industries Development Email: revette@la.gov Phone: 225-342-5368 P.O. Box 94185 Baton Rouge, LA 70804-9185	http://www.lded.state.la.us/	The Louisiana Economic Development provides successful economic and community development programs, provides resources, training and tools to build your community's capacity to attract, retain and grow business.			The Economic Development agency encourages and provides energy information and policy advice for new energy projects. This agency can provide business development support as well as policy and planning support
Massachusetts	**Ann Berwick, Under Secretary of Energy** Executive Office of Energy and Environmental Affairs Email: ann.berwick@state.ma.us Phone: 617-626-7300 100 Cambridge Street, Suite 900 Boston, MA 02114	http://www.mass.gov	The Executive Office of Energy and Environmental Affairs is the only state Cabinet-level office in the country that oversees both environmental and energy agencies. In putting energy and environment under one roof, Governor Patrick set a course toward a clean energy future, and the six agencies under EEA are following that direction with vigor, in close collaboration with the Legislature and many outside partners.	**Ann Berwick, Under Secretary of Energy** Email: ann.berwick@state.ma.us Phone: 617-626-7300 100 Cambridge Street, Suite 900 Boston, MA 02114	http://www.mass.gov/?pageID=eoeeahomepage&L=1&L0=Home&sid=Eoeea	The Executive Office of Energy and Environmental Affairs oversees the Dept. of Ag Resources, Dept. of Conservation and Recreation, Dept. of Energy Resources, Dept. of Env. Protection, Dept. of Fish and Games, Dept. of public Utilities. The Executive Office will serve as the general contact and provide information and contact information for each state agency.
Maryland	Spoke with Chris Rice. Mr. Rice is believed to be the proper contact but still waiting for confirmation					

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STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
Maine	**James F. Nimon, Director** Office of Business Development Department of Economic and Community Development Email: james.nimon@maine.gov Phone: 207-624-9804 59 State House Station Augusta ME 04333	www.businessinmaine.com	DECD serves as the umbrella organization to the offices of Tourism, Business Development, the International Trade Center, Community Development, Film and Innovation and Science			The DECD encourages and provides energy information and policy advice for new energy projects. The DECD will serve as the general contact and provide information and contact information for each state agency.
Michigan	**Jan Patrick** DELEG/Energy Bureau Email: patrickj@michigan.gov Phone: (517) 241-6153	http://www.michiganadvantage.org	From site location assistance to job training grants, from help with permits to tax abatements, we're the state's official economic development corporation -- a one-stop resource for businesses seeking to grow in Michigan.			MEDC will act as the general contact and provide help with issues from permits to tax abatements - a one-stop resource for business.
Minnesota	**Janet Streff, Manager** State Energy Office Email: janet.streff@state.mn.us Phone: 651-296-5120 85 7th Place East St. Paul, MN 55101	http://www.state.mn.us/	The MN Department of Commerce's mission is to ensure equitable commercial and financial transactions and reliable utility services by: regulating and licensing business activity in more than 20 industries; investigating and resolving consumer complaints; advocating the public's interest before the Public Utilities Commission; and, administering various state programs.			The MN Department of Commerce provides energy information and policy advice for new energy projects. It can provide funding to support and promote the beneficial adoption of new renewable energy technologies.
	Phil Smith, Energy Specialist Minnesota Office of Energy Security Email: phil.smith@state.mn.us Email2: energy.info@state.mn.us Phone: 651-296-5175 Phone2: 800-657-3710 85 7th Place East St. Paul, MN 55101	http://www.state.mn.us				
Missouri	**Roger Korenberg** Missouri Department of Natural Resources Energy Center Phone: 573-751-3443 P.O. Box 176 Jefferson City, MO 65102	http://www.dnr.mo.gov/energy/	The Missouri Department of Natural Resources' Energy Center is a nonregulatory state agency that works to protect the environment and stimulate the economy through energy efficiency and renewable energy resources and technologies.			The Missouri DNR can provide environmental permit forms and give technical and financial assistance for energy efficiency and renewable energy projects.
Mississippi	**Motice Bruce, Executive Director** Mississippi Development Authority Email: mbruce@mississippi.org Phone: 601-359-6601 501 North West Street Jackson, Mississippi 39201	http://www.mississippi.org/	The Mississippi Development Authority (MDA) is the State of Mississippi's lead economic and community development agency. More than 250 employees are engaged in providing services to businesses, communities and workers in the state.			MDA will act as a general contact and provide additional information and contacts through local elected officials, main street programs and the chamber of commerce.
Montana	**Mike Volesky, Natural Resource Policy Advisor** Governor's Office Email: mvolesky@mt.gov Phone: 406-444-7857 PO Box 200801 Helena, MT 59620-0801	http://governor.mt.gov/cabinet/contactus.asp	The Governor's Office of Economic Development serves to advise the Governor on policy issues related to economic development; lead the state's business recruitment, retention, expansion, and start-up efforts; and serves as the state's primary economic development liaison between federal, state, and local agencies, Montana tribal governments, private nonprofit economic development organizations and the private sector			The Governor's Office of Economic Development reports to the Governor providing information required to form policy decisions. This Office will not provide required permits but can direct a developer to contacts within each proper state agency.

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STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
	Tom Kaiserski, Program Manager Energy Promotion and Development Division Email: tkaiserski@mt.gov Phone: 406-841-2034 PO Box 200501 Helena MT 59620-0501	http://commerce.mt.gov/energy/about.asp	The Energy Promotion and Development Division was created in 2007 to help implement Governor Schweitzer's commitment to 'clean and green' energy development in Montana.			The Energy Promotion & Development Division works directly with the Governor's Office and other state agencies to help facilitate the permitting, siting, and financial issues.
	Tom Ring, Environmental Specialist (Montana Major Facility Siting Act) Department of Environmental Quality Email: tring@mt.gov Phone: 406-444-6785 1520 East 6th Avenue Helena, MT 59620	www.deq.state.mt.us/				
North Carolina	**Star Brown, Chief** Energy Efficiency N.C. State Energy Office Phone: 919-733-1897 1830-A Tillery Place Raleigh, NC 27604	http://www.energync.net/	The State Energy Office is North Carolina's lead agency for energy programs and services and serves as the official source for energy information and assistance for consumers, businesses, government agencies, community colleges and schools and the residential, commercial and industrial sectors.			The state energy office encourages and provides energy information and policy advice for new energy projects. This agency can provide business development support as well as policy and planning support
	Bob Leker, Program Manager Renewable Energy N.C. State Energy Office Phone: 919-733-1907 1830-A Tillery Place Raleigh, NC 27604	http://www.energync.net/				
	Cythia Mosseley, Program Manager Alternative Fuels N.C. State Energy Office Phone: 919-733-1896 1830-A Tillery Place Raleigh, NC 27604	http://www.energync.net/				
	Bill Gilmore, Deputy Director Fossil Fuel Projects N.C. Utilities Commission Email: gilmore@ncuc.net Phone: 919-733-9563 430 North Salisbury Street Dobbs Building Raleigh, NC 27603	http://www.ncuc.commerce.state.nc.us/index.htm	To a limited degree, the Commission regulates electric membership corporations, small power producers, and electric merchant plants. The Commission is also responsible for administering programs in North Carolina to ensure the safety of natural gas pipelines.			The Utilities Commission will serve as another general energy contact and provide information for fossil fuel development.
North Dakota	**Paul T. Govig, Division Director** North Dakota Division of Community Services Email: pgovig@state.nd.us Phone: 701-328-5300 1600 East Century Avenue, Suite 2 PO Box 2057 Bismarck, ND 58502	http://www.communityservices.nd.gov/about/	To provide the people of North Dakota with effective, efficient and customer oriented administration of federal and state programs for Community Development, Energy Efficiency and Renewable Energy, Housing; and Self Sufficiency.	**Ron Rauschenberger, Chief of Staff** Office of the Governor Email: rrausche@nd.gov Phone: 701-328-2222	www.governor.nd.gov	The Office of the Governor encourages and provides energy information for 4,000 existing megawatts of electricity and provides policy advice for new energy projects. This agency already provides advice for a potential coal to liquids facility and a new coal gasification plant.
Nebraska	**Neil Moseman, Energy Office Director** Nebraska Energy Office Email: Neil.Moseman@nebraska.gov Phone: 402-471-2867 1111 "O" Street, Ste. 223 Lincoln, NE 68508	http://www.neo.ne.gov/	Promotes the efficient, economic and environmentally responsible use of energy.			The Nebraska Energy Office encourages and provides energy information and policy advice for new energy projects. This agency will not provide the appropriate permits for an energy project but can provide contacts in each pertinent state agency.
	Jerry Loos Nebraska Energy Office Email: jerry.loos@nebraska.gov Phone: 402.471.3356 1111 "O" Street, Ste. 223 Lincoln, NE 68508	http://www.neo.ne.gov/				

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STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
New Hampshire	**Amy Ignatius, Director** New Hampshire Office of Energy and Planning Email: amy.ignatius@nh.gov Phone: 603-271-2155 NH Office of Energy and Planning 4 Chenell Drive Concord, NH 03301	http://www.nh.gov/oep/index.htm	Responsible for exploring opportunities to expand the use of renewable, domestic energy resources such as biomass, wind and solar energy;			The New Hampshire Office of Energy and Planning provides energy information and policy advice for new energy projects. This agency will not provide the appropriate permits for an energy project but can provide contacts in each pertinent state agency.
	Roy Duddy, Director Business Resource Center NH Department of Recreation and Economic Development Email: royduddy@dred.state.nh.us Phone: 603-271-2591 x103 172 Pembroke Road P.O. Box 1856 Concord, NH 03302	http://www.nheconomy.com/	The New Hampshire Business Resource Center and the International Trade Resource Center offer resources to enhance the economic activities of the state through business attraction outreach, in-state business expansion efforts, and facilitation of government and international sales			The NH Division of Economic Development will work with private organizations to promote energy efficient technologies. The Division does not issue permits but can provide information for funding and other contacts within state government.
	Tom Frantz Public Utilities Commission Email: tom.frantz@puc.nh.gov Phone: 603-271-2431 21 S Fruit St # 10 Concord, NH 03301	www.puc.nh.gov/	The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, water and sewer utilities for issues such as rates, quality of service, finance, accounting, and safety.			The NH Public Utilities Commission is vested with jurisdiction over issues such as finance and accounting of energy projects. The PUC will also serve as a general contact and provide information and contact information for other state agencies.
New Jersey	**Joe Carpenter** Department of Environmental Protection Phone: 606-984-3438 DEP Main Building 401 East State Street Trenton, NJ	http://www.state.nj.us/dep/	The NJDEP is involved with issues such as global warming and sea-level rise, renewable energy development, flood control, storm water management, natural resource protection, storm preparedness and ecological sustainability.			The NJDEP will serve as a general contact and provide the appropriate environmental permits for a CTL facility.
	Benjamin Scott Hunter, Renewable Energy Program Administrator, Office of Clean Energy New Jersey Board of Public Utilities Email: benjamin.hunter@bpu.state.nj.us Phone: (609) 777-3300 44 South Clinton Avenue P.O. Box 350 Trenton, NJ 08625	http://www.bpu.state.nj.us	The Board of Public Utilities is a regulatory authority with a statutory mandate to ensure safe, adequate, and proper utility services at reasonable rates for customers in New Jersey.			The NJ Board of Public Utilities is responsible for addressing energy reform and encouraging energy projects. The NJPU will serve as a general contact and provide policy advice for a CTL facility.
New Mexico	**Craig O'Hare, Special Assistant for Renewable Energy** Energy Conservation and Management Division Email: craig.ohare@state.nm.us Phone: 505-476-3207 1220 South St. Francis Dr. Santa Fe, NM 87505	http://www.emnrd.state.nm.us/ECMD/index.htm	The Energy Conservation and Management Division develops and implements effective clean energy programs – renewable energy, energy efficiency and conservation, clean fuels and efficient transportation – to promote environmental and economic sustainability for New Mexico and its citizens			The Energy Conservation and Management Division will serve as a general contact and provide information and contacts for each state agency. The Division will also identify energy incentives for the development of a CTL facility.
	Fernando Martinez, Division Director Energy Conservation and Management Division Email: fernando.r.martinez@state.nm.us Phone: 505-476-3312 1220 South St. Francis Dr. Santa Fe, NM 87505	http://www.emnrd.state.nm.us/ECMD/index.htm				
Nevada	Contacted Dr. Gecol, Director NV State Office of Energy and Nick Vander Poel, Deputy Director. Waiting for confirmation	http://energy.state.nv.us/default.htm	The NV State Office of Energy is responsible for implementing the Governor's plan, which includes components that encourage energy conservation, facilitate electric generation and transmission permitting, facilitate natural gas transmission permitting, and encourage renewable energy development.			The State Office of Energy will provide energy information and policy advice for new energy projects. This agency will not provide the appropriate permits for an energy project but can provide contacts in each pertinent state agency.

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STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
New York	**Dana Levy, Program Manager (Co-Generation)** NY State Energy Research and Development Authority Email: dll@nyserda.org Phone: 518-862-1090 x3377 17 Columbia Circle Albany, NY 12203	http://www.nyserda.org/default.asp	NYSERDA is a public benefit corporation created in 1975. Earliest efforts focused solely on research and development with the goal of reducing the State's petroleum consumption. Subsequent research and development projects focused on topics including environmental effects of energy consumption, development of renewable resources, and advancement of innovative technologies			The NYSERDA will provide technical and financial assistance for energy efficiency and renewable energy projects. NYSERDA cannot provide the appropriate permits for a CTL facility but can provide the appropriate contacts within each agency.
	John Saint Cross, Program Manager (Renewable) NY State Energy Research and Development Authority Email: js1@nyserda.org Phone: 518-862-1090 x3384 17 Columbia Circle Albany, NY 12203	http://www.nyserda.org/default.asp				
Ohio	**Brad Biggs** Ohio Department of Development Phone: 614-644-8201 77 S. High St., PO Box 1001 Columbus, OH 43216	http://www.odod.state.oh.us/	Working with our partners across business, state and local governments, academia, and the non-profit sector, the Ohio Department of Development works to attract, create, grow, and retain businesses through competitive incentives and targeted investments.	**Brad Biggs** Ohio Department of Development Phone: 614-644-8201 77 S. High St., PO Box 1001 Columbus, OH 43216	http://www.odod.state.oh.us/	The Department of Development will provide financial assistance information for energy efficiency and renewable energy projects, including CTL projects. The Department of Development cannot provide the appropriate permits for a CTL facility but can provide the appropriate contacts within each agency.
	Todd Nein Ohio Air Quality Development Authority Email: todd.nein@aqda.state.oh.us Phone: 614-224-3383 50 W Broad St # 1718 Columbus, OH 43215	www.ohioairquality.org	The Ohio Air Quality Development Authority's primary mission is to provide for the conservation of air as a natural resource of the state by preventing or abating air pollution. Through its Ohio Coal Development Office, OAQDA also co-funds the research, development, and deployment of technologies that promote the use of Ohio's vast reserves of high-sulfur coal in an economical, environmentally sound manner.	**Todd Nein** Ohio Air Quality Development Authority Email: todd.nein@aqda.state.oh.us Phone: 614-224-3383 50 W Broad St # 1718 Columbus, OH 43215	www.ohioairquality.org	OCDO supports projects ranging from applied research through commercial demonstration through cost sharing. OCDO will not provide the appropriate environmental permits but will assist in business development.
Oklahoma	**Rena Steeds, Economic Development Specialist** Business Development Division Email: rena_steeds@okcommerce.gov Phone: 405-815-5143 900 N. Stiles P.O. Box 26980 Oklahoma City, OK 73126	http://www.okcommerce.gov/	The Oklahoma Department of Commerce is the primary economic development arm of the state government. Our mission is to increase the quantity and quality of jobs available in Oklahoma by supporting communities; supporting the growth of existing businesses and entrepreneurs; attracting new businesses; and promoting the development and availability of a skilled workforce.			The Department of Commerce is responsible for assisting the planning and indentifying incentives of any new energy project. The Department will also serve as the general contact and provide contact for environmental permitting.
	Vaughn Clark, Director Oklahoma State Energy Office Phone: 800-879-6552 Email: vaughn_clark@odoc.state.ok.us 900 North Stiles Ave. Oklahoma City, OK 73104	http://www.okcommerce.gov				
Oregon	**Thomas Stoops, Siting manager** Department of Energy Email: Tom.Stoops@state.or.us Phone: 503-378-8328 625 Marion Street NE Salem, OR 97301	www.oregon.gov/energy	The mission of the Oregon Department of Energy is to ensure Oregon has an adequate supply of reliable and affordable energy and is safe from nuclear contamination, by helping Oregonians save energy, develop clean energy resources, promote renewable energy, and clean up nuclear waste.			The Department of Energy offers loans, tax credits, information, and technical expertise for energy projects. The Department of Energy will not issue environmental permits but will act as the general contact and provide information and contact information within each state agency.
	Mike W. Grainey, Director Department of Energy Email: michael.w.grainey@state.or.us Phone: 503-378-4040 625 Marion Street NE Salem, OR 97301	www.oregon.gov/energy				
Pennsylvania	Spoke with Dan Griffiths, Director of PA. Office of Energy and Tech. Deployment. He recommended Malcom Furman, still waiting for confirmation					

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STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
Rhode Island	**Andrew Dzykewicz, Commissioner RI Office of Energy Resources** RI Office of Energy Resources Email: Adzykewicz@energy.ri.gov Phone: 401-574-9119 One Capitol Hill Providence, RI 02908	http://www.energy.ri.gov/index.php	The Office of Energy Resources is working with community agencies, the University of Rhode Island, local businesses, and utility providers to develop assistance and energy efficiency programs			The Office of Energy Resources cannot provide the required environmental permits but can act as a general contact and provide information for other pertinent state agencies. This agency will also be paramount on any future energy policies.
	Janet Keller, Deputy Director State Energy Programs RI Office of Energy Resources Email: jkeller@energy.ri.gov Phone: 401-574-9126 One Capitol Hill Providence, RI 02908	http://www.energy.ri.gov/index.php				
South Carolina	**Bill Cronin, Director** Global Business Development South Carolina Department of Commerce Email: bcronim@sccommerce.com Phone: 803-737-0421 1201 Main Street, Suite 1600 Columbia, SC 29201	http://www.sccommerce.com/	The South Carolina Department of Commerce works to promote economic opportunity for individuals and businesses. As South Carolina's leading economic development agency, the Department of Commerce works to recruit new businesses and help existing businesses grow.			South Carolina Commerce is responsible for assisting, planning and indentifying incentives of any new energy project. The Department will also serve as the general contact and provide contacts for environmental permitting.
South Dakota	**Hunter Roberts, Energy Policy Director** Department of Tourism and State Development Email: hunter.roberts@state.sd.us Phone: 605-773-3301 771 East Wells Ave. Pierre, SD 57501	http://www.sdeia.com/index.asp	The Infrastructure Authority brings together public and private entities in an effort to identify and address South Dakota's needs in the area of renewable electrical energy development. The Authority helps develop energy production facilities in South Dakota and provide financing for new and expanding facilities.			The Infrastructure Authority is vested with developing energy production facilities in South Dakota and providing financing for new and expanding facilities. The Infrastructure Authority will also serve as the general contact and provide information and contact information for environmental permitting.
Tennessee	**Ryan Gooch, Director Energy Policy** TN Energy Division Email: ryan.gooch@state.tn.us Phone: 615-741-2373 312 Rosa L. Parks Avenue, Tenth Floor Nashville, TN 37243-1102	http://tennessee.gov/ecd/energy.htm	The mission of the Energy Division is to promote sound economic development policies and programs both to retain existing business and industry and foster new investment and job creation throughout the state. Through grants from the US Department of Energy, the Energy Division provides a broad range of energy efficiency programs to business and industry, state and local governments, schools, and residential consumers. All programs focus on energy efficiency measures and promote energy cost and dollar savings.	**Ryan Gooch, Director Energy Policy** TN Energy Division Email: ryan.gooch@state.tn.us Phone: 615-741-2373 312 Rosa L. Parks Avenue, Tenth Floor Nashville, TN 37243-1102	http://tennessee.gov/ecd/energy.htm	The TN Energy Division cannot provide the required environmental permits for a CTL facility but can act as a general contact and provide information for other pertinent state agencies. This agency will also be paramount on any future energy policies.
Texas	**Dub Taylor, Director** State Energy Conservation Office Phone: 512-463-1931 Email: dub.taylor@cpa.state.tx.us 111 East 17th Street, #1114 Austin, Texas 78701	http://www.seco.cpa.state.tx.us/	The mission of the State Energy Conservation Office (SECO) is to maximize energy efficiency while protecting the environment.	**Alan Batcheller, Director of Remediation Services** Texas Commission on Environmental Quality Email: abatchel@tceq.state.tx.us Phone: 512-239-5800 P.O. Box 13087 Austin, TX 78711-3087	http://www.tceq.state.tx.us/	The Texas Commission on Environmental Quality (TCEQ) is the environmental agency for the state. TCEQ will act as the general contact and will be the state regulatory authority for CTL.
Utah	**Jason Berry, Energy Office Manager** Utah Geological Survey Email: jasonberry@utah.gov 1594 W. North Temple, PO 146100 Salt Lake City, UT 84114	http://geology.utah.gov/sep/	The Utah Geological Survey administers the DOE State Energy Program in Utah and advises the state's executive and elected leaders on energy policy.	**Ronald W. Daniels, Energy Policy Coordinator** Office of Governor's Energy Advisor Phone: 801-538-8817 324 South State Street Salt Lake City, UT 84111	http://www.energy.utah.gov/energy/energy_advisor.html	The Utah Governor's Energy Policy Advisor will not provide the required permits for a CTL facility, but can act as a general contact and provide information for other state agencies. This agency will also be paramount on any future energy policies.
Virginia	**John W. Warren, Director** Virginia Division of Energy Email: john.warren@dmme.virginia.gov Phone: 804-692-3200 Ninth Street Office Building, 8th Floor 202 North Ninth Street Richmond, VA 23219	http://www.dmme.virginia.gov/divisionenergy.shtml	The primary goal of the Division of Energy is to advance sustainable energy practices and behaviors. The Division of Energy works to foster growth of emerging and sustainable energy industries and infrastructures.	**Twyla Powell, Business Development Manger** Business Development Group Virginia Economic Development Partnership Email: Tpowell@YesVirginia.org Phone: 804-545-5723 901 East Byrd Street Richmond, VA 23218	www.yesvirginia.org/	The Virginia Business Development Group provides energy information and policy advice for new energy projects. This agency will not provide the appropriate permits for an energy project but can provide contacts in each pertinent state agency.

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STATE	GENERAL ENERGY CONTACT	STATE ENERGY DEPARTMENT LINK	DESCRIPTION OF AGENCY	CTL CONTACT	CTL AGENCY WEBLINK	GENERAL INFORMATION
Vermont	**Dave Lamont, Director of Regulated Utility Planning** Public Service Board Email: dave.lamont@state.vt.us Phone: 802-828-4082 112 State St # 4 Montpelier, VT 05620	www.state.vt.us/psb/	The Board's mission is to ensure the provision of high quality public utility services in Vermont at minimum reasonable costs.			The Board will serve as a general contact and provide information and contact for each pertinent state agency. The Board does provide permits for net metering.
	Anne Margolis, Clean Energy Development Fund Manager Public Service Board Email: anne.margolis@state.vt.us Phone: 802-828-4017 112 State St # 4 Montpelier, VT 05620	www.state.vt.us/psb/	The Board's mission is to ensure the provision of high quality public utility services in Vermont at minimum reasonable costs.			
Washington	**Tony Usibelli, Assistant Director for Energy Policy** Department of Community, Trade & Economic Development Phone: 360-725-3110 Email: tonyu@cted.wa.gov	http://www.cted.wa.gov/	The Washington State Department of Community, Trade and Economic Development (CTED) is the lead agency charged with enhancing and promoting sustainable communities and economic vitality in our state.			The CTED encourages and provides energy information and policy advice for new energy projects. This agency will not provide the appropriate permits for an energy project but can provide contacts in each pertinent state agency.
	Carolee Sharp, Executive Assistant WA State Dept of CTED Energy Policy Division PO Box 43173 906 Columbia St SW Olympia WA 98504-3173 360.725.3118	http://www.cted.wa.gov/				
Wisconsin	**Judy Ziewacz, Director** Office of Energy Independence Email: judy.ziewacz@wisconsin.gov Phone: 608-261-6609 17 W. Main St., Suite 429 Madison, WI 53703	http://power.wisconsin.gov/	The WI Office of Energy Independence energy strategy relies on its ability to become a leader in groundbreaking research and developing technologies to make alternative energies more affordable and available to all Wisconsin citizens.			The WI Office of Energy cannot provide the required permits but can act as a general contact and provide information for other pertinent state agencies. This agency will also be paramount on any future energy policies in the state of WI.
West Virginia	**Jeff Herholdt, Director** WV Division of Energy Email: jherholdt@energywv.org Phone: 304-957-2027 State Capitol Complex Building 6, Room 645 Charleston, WV 25305	http://www.energywv.org/community/eep.html	The West Virginia Division of Energy is responsible for the formulation and implementation of fossil, renewable and energy efficiency initiatives designed to advance energy resource development opportunities and provide energy services to businesses, communities and homeowners in West Virginia.	**Jeff Herholdt, Director** WV Division of Energy Email: jherholdt@energywv.org Phone: 304-957-2027 State Capitol Complex Building 6, Room 645 Charleston, WV 25305	http://www.energywv.org/community/eep.html	The West Virginia Division of Energy is responsible for the formulation and implementation of fossil, renewable and energy efficiency initiatives designed to advance energy resource development. This agency cannot provide the required permits but can act as a general contact and provide information for other pertinent state agencies.
Wyoming	**Tom Fuller, Manager** State Energy Programs Email: tom.fuller@wybusiness.org Phone: 307-777-2800 214 West 15th St. Cheyenne, WY 82002	http://www.wyomingbusiness.org/business/energy.aspx	The Wyoming Business Council administers the State Energy Program, funded by the U.S. Department of Energy. The program works to expand opportunities for alternative or renewable energy use in Wyoming using domestic fuels or resources	**Rob Hurless, Energy and Telecom Advisor** Office of the Governor Email: rhurle@state.wy.us Phone: 307-777-8521 State Capitol, 200 West 24th Street Cheyenne, WY 82002	http://governor.wy.gov/	The Energy and Telecom Advisor reports to the Governor, providing information required to form policy decisions. This Office will not provide required permits but can direct a developer to contacts within each proper state agency.

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APPENDIX 5
Permit Map

Table of Contents

Acknowledgement

This material is based upon work supported by the Department of Energy, National Energy Technology Laboratory in furtherance of Cooperative Agreement Number DE-FC26-06NT42449 for Production of High-Hydrogen Content Coal Derived Liquids.

1.0 INTRODUCTION

Successful coal gasification project development relies on receipt of required permits in a timely and predictable manner. This document outlines the basic environmental permits (and permit approval timeframes) required for the operation of a gasification project.

Interaction with numerous local, state and federal governmental entities, as well as private entities, will be required when requesting permits and approvals for a coal gasification facility. These agencies include:

- Kentucky Energy and Environment Cabinet
- Division of Waste Management (DWM)
- Division of Water (DOW)
- Division for Air Quality (DAQ)
- Kentucky Siting Board of the Public Service Commission
- Kentucky Public Protection Cabinet (KPPC)
- Kentucky State Fire Marshall
- Kentucky Office of Housing, Buildings and Construction
- US Environmental Protection Agency (EPA)
- Federal Energy Regulatory Commission (FERC)
- U.S. Army Corp of Engineers (Corps)
- local electric utility
- Regional Transmission Organization (RTO)

This report also contains Gantt charts for each major permit action which graphically depict the process and times needed for typical state and federal permits and approvals that may be required. Timeframes were developed through interpretation of state and federal regulations and previous industry permitting experiences.

Permit applications, guidance documents and forms are provided through hyperlinks within each section that provide electronic access to the respective permit applications, guidance documents and forms. Activities such as plans required to be prepared, implemented and maintained on site but not submitted to the regulatory agency are not reflected in the Gantt charts.

2.0 ENVIRONMENTAL PERMITS ISSUED BY THE STATE OF KENTUCKY

Permits issued by Kentucky regulatory agencies will include those impacting air emissions, waste generation and disposal, and impact on water resources.

2.1 Kentucky Hazardous Waste Generator Registration

Division of Waste Management, Hazardous Waste Branch

If hazardous waste will be generated (i.e. mercury), the facility must register for a U.S. Environmental Protection Agency (EPA) ID number issued by the Kentucky Division of Waste Management, Hazardous Waste Branch (401 KAR 32:010$_{(2005)}$). Because the permitting process to dispose of waste on-site is very extensive and requires complex design work, it is recommended that a facility plan for off-site disposal of hazardous waste at a permitted disposal facility.

A developer will submit a completed Notification of Hazardous Waste Activity Form DEP-7037. The Handbook for Hazardous Waste Generators helps work through the application process. The facility must also submit a $300 application fee for Small and Large Quantity Generators with Form DEP-7037 to the DWM. There is no public notice or hearing required. The issuance of the EPA ID number will be made within 90 days of the submitted completed application.

The volume of hazardous waste a gasification facility will generate is unknown. However, based on the mercury content of coal, the facility will likely be classified as a small quantity generator. A facility is classified based on the volume of waste it generates as described in the following table.

Hazardous Waste Generators

Conditionally Exempt, Small Quantity	Small Quantity	Large Quantity
<220 lbs/month – not acutely hazardous waste	220-2200 lbs/month – not acutely hazardous waste	> 2200 lbs/month – may include acutely hazardous
Registration not required, but advisable and free	Registration required	Registration required
Manifest not required	Waste manifest required	Waste manifest required
		Closure of accumulation area required
May accumulate up to 2200 lbs	Ship within 180 days	Ship within 90 days
	Annual Report, Hazardous Waste Assessment and fee	Annual Report, Hazardous Waste Assessment and fee

An annual renewal for both small quantity and large quantity generators must be submitted to the Cabinet on the Notification of Hazardous Waste Activity Form at least 45 days before the expiration date shown on the generator's registration.

All transporters and treatment, storage and disposal (TSD) facilities involved in disposing hazardous waste must also have EPA identification numbers. Kentucky follows the federal rules for shipping hazardous wastes to a Treatment Storage Disposal (TSD) facility. The generating facility should confirm that the shipper and disposal facility are properly registered.

Hazardous Waste Generator
Registration Process Timeline

2.2 Kentucky Special Waste Landfill Permit

Division of Waste Management,
Solid Waste Branch

If a facility establishes, constructs, operates, maintains or permits the use of a waste site or facility, it must first obtain a permit (KRS §224.40-305 (2006)) from the Kentucky Division of Waste Management, Solid Waste Branch. Coal gasification waste is classified as special waste. Therefore, a special waste landfill permit will be required to dispose of the coal combustion by-product, unless it qualifies as a “beneficial reuse”.

Special Waste Regulations are found in 401 KAR Chapter 45. The special waste landfill application is a single-phased submittal of the fee and form. Upon receipt, the Solid Waste Branch reviewer has 45 days to determine if the application is complete. If the application is found to be incomplete, the applicant is given an opportunity (30 days) to remedy any deficiencies, following which the reviewer will assess the new submittal (another 30 days). Once the application is complete, DWM has 180 days to approve or deny the application. Tolling of the mandatory approval or denial time will occur when an application is returned to the applicant to remedy any deficiencies. The Solid Waste Branch has time to consider comments received during the public comment period or a public hearing, in addition to its review schedule.

As of May 2009, the application fee for a special waste permit is $5,000 and the developer can expect to pay approximately $200,000 - $400,000 in engineering and consulting fees for preparation of the application. The application fee accompanies the facility's DEP 7094A form and attachments, which together make up the special waste landfill permit application. The information required in the application is comprehensive including both landfill design and engineering as well as detailed information about the impact of the proposed landfill on the property and surrounding community. Engineering drawings, specifications and studies must be certified by a professional engineer registered in Kentucky. The preparation of the application will include substantial geotechnical exploration and design and can be expected to consume three to six months prior to submittal.

After the Solid Waste Branch determines that the application is complete, public notice is published in a daily or weekly major local newspaper of general circulation where the proposed site or facility is located. Verification of publication is submitted after the publication date and a public comment period begins. The Solid Waste Branch may hold a public hearing if one is requested or when a significant degree of public interest exists concerning a special waste site or facility permit decision.

When the final permit is issued, the Solid Waste Branch will include a response to comments which specifies which provisions of the draft permit have been changed in the final permit decision and the reasons for the change; and briefly responds to all significant comments on the draft permit raised during the public comment period, or during the public hearing.

A landfill permit has a five year life and must be renewed by submitting Form 7095 at least 180 days prior to the expiration of the issued permit. In addition to having a permitted special waste landfill, the facility must also have a certified landfill operator (401 KAR 47:070, Section 2). Training classes are provided by the DWM with an examination on the last day of the training to test the applicant's knowledge.

Special Waste Process Timeline

2.3 General Storm Water Permit and KPDES Permit

Division of Water

A General Storm Water construction permit covers all new and existing storm water discharges associated with construction activity. The construction of a coal gasification facility at any site will require a General Storm Water construction permit (401 KAR 5:055, Section 5). General Storm Water construction permits are issued by the Kentucky Division of Water. If the permit is issued to the private contractor who will perform the construction activities of the gasification facility, the contractor will be responsible for implementing the storm water and runoff control during construction (Figures 1, 3A, 3B).

The Kentucky Pollutant Discharge Elimination System (KPDES) regulations require a permit for the discharge of pollutants from any point source into waters of the Commonwealth. The developer may chose to incorporate the storm water construction permit into the KPDES permit.

Notice of Intent for Storm Water Construction Activities

Before beginning construction activities the operator (defined as the party who has operational control on the site: owner, operator or both) has to submit a signed Notice of Intent for Storm Water Construction Activities (NOI-SWCA) to the Division of Water, KPDES-Branch. The applicant can chose to use the Division of Water's electronic portal which could result in notification of coverage in 7 days. A paper application must be submitted to the DOW a minimum of 30 days prior to the commencement of construction activities. The authorization to discharge under the General Permit starts upon the issuance of a written notification of coverage unless delayed by a notice of deficiency to the applicant by the DOW. There is no automatic coverage. No fee is required for a general storm water construction permit (401 KAR 5:310).

The NOI-SWCA must contain the following general information:

- Facility operator information
- Facility/site location information
- Site activity information
- Other required environmental approvals, permits or certification
- NOI preparer information
- Topographic site map

Additional Requirement under a General Permit

In addition to obtaining authorization, the general permit holder is required to prepare and implement a storm water pollution prevention plan (SWPPP) prior to start of construction. The SWPPP must include erosion prevention measures, sediment controls measures and other site management practices necessary to prevent the discharge of sediments and other pollutants into waters of the state. The SWPPP must be maintained up-to-date and available for review by the Division of Water upon site inspection, however it does not have to be submitted or approved prior to permitting.

Permitees are required to minimize the area of disturbance and the period of time the disturbed area is exposed without implementing temporary or final stabilization practices. Permitees are also required to maintain a buffer zone of at least 25 feet between any disturbance and waters categorized as High Quality Waters or Impaired Waters (non-construction related impairment). The buffer zone must be doubled to 50 feet if discharge is to waters categorized as Impaired Waters due to sediment load.

Once construction is completed and cover is established, the permittee is required to file a notice of termination. The general permit is automatically revoked once the individual KPDES permit for the discharge of other wastewaters, which requires the development and implementation of a Best Management Practices (BMP) plan, is issued. Storm water discharge is then covered under Form F of that permit.

KPDES Permit

The KPDES permit application for a gasification facility includes three forms. General instructions are found at KPDES General Instructions. All KPDES applications must include KPDES Form 1 (401 KAR 5:060 (2002)). This is a general form that requests information regarding facility location, owner/operator addresses, existing environmental permits, and other similar information.

In addition to Form 1, the facility must complete a form that relates directly to the type of operation. A coal gasification facility will use Form C – Process Water Associated with Manufacturing Establishments and Mining Operations (401 KAR 5:060 (2002)). (KPDES Form C) and Form F – Stormwater Associated With Industrial Activity (401 KAR 5:060 (2002)) (See Form F).

The DOW will determine if the application is administratively complete before it begins the technical review process. If the application is incomplete, the applicant will be requested to supply the missing information. The review process is scheduled to be completed within 180 days following a determination the application is administratively complete, but deficiencies can extend that period up to an additional 180 days. A public notice and comment period is required after the permit has been drafted and a public hearing may be held.

General Permit Process Timeline for Stormwater from Construction

KPDES Permit Process Timeline

2.4 Floodplain Construction Permit and Water Quality Certification

Division of Water,
Water Resources Branch
Floodplain Management Section/
Water Quality Certification

The DOW Floodplain Management Section of the Water Resources Branch manages approvals for proposed construction and other activities within the 100-year floodplain of all streams in the Commonwealth (KRS §151.230 (2000) and 401 KAR 4:010 - 060). In addition, activities which disturb wetlands or streams may also require a Water Quality Certification Permit. The same application is used for a Floodplain Construction Permit and a Water Quality Certification. Instructions are also available to help in completing the application.

If there is existing flood data on the proposed site (i.e., National Flood Insurance Program flood maps, Corps of Engineers flood studies or previous permit data), the permit review will begin. If there is no existing data, survey information must be submitted in order to perform an in-house flood study of the area.

All plans submitted must include:

- name of the project,
- date,
- scale of maps,
- name of stream,
- direction of flow,
- purpose and intended use,
- scheduling of activities, and
- location.

For docks or water intakes, a properly completed Stream Construction Permit Application Data Sheet, a location map (preferably USGS), the elevation of docks, top of structure, extreme high water, and normal pool, and the distance that the structure will project into stream will need to be provided.

Floodplain Construction

Once the Floodplain Management Section decides to issue the permit, public notice is sent to individuals who may be directly impacted by the project and is published if the impact may extend beyond the immediate area.

Following public notice and comment, if the project meets regulatory requirements, a permit is issued for one year during which the construction must begin. If construction begins within that one-year period, the permit is valid until project completion. The developer may request an extension if work will not begin within one year of the permit date. After the completion of the construction, the developer must notify the Cabinet and terminate the permit.

Water Quality Certification
If construction work involves bank stabilization, dredging or relocation, or the potential for wetlands disturbance, a 401 Water Quality Certification will be required. Although the DOW uses the same application for both Water Quality Certifications and Floodplain Construction Permits, Water Quality Certification Applications have a separate public notice and comment period from the floodplain construction notice.

Floodplain Construction and Water Quality Certification Process Timeline

2.5 Water Withdrawal Permit

Division of Water.
Water Withdrawal Permitting

The water withdrawal program governs all withdrawals of water greater than 10,000 gallons per day from any surface, spring or groundwater source (KRS §151.140-150 and 401 KAR 4:010).
An application for a water withdrawal permit should be made three to six months prior to the desired start-up date. Permits require monthly reporting of actual daily withdrawals amounts. The application form is found at Water Withdrawal Application).

The withdrawal permit will specify an effective date within three years after the date of issue. The water required by the applicant is then reserved for its later use provided the amount of water continues to be available, additional water is available for other uses and the applicant provides quarterly status reports of the progress of the project. Withdrawals must begin within six months following the effective date. An extension or reissuance can be requested if needed.

Water Withdrawal Permit Process Timeline

2.6 Groundwater Protection Plan

Division of Water

If a facility is storing, treating, disposing, or handling hazardous waste, solid waste, or special waste in landfills, incinerators, surface impoundments, tanks, drums or other containers, or in piles, it must prepare and implement a Groundwater Protection Plan (GPP) (401 KAR 5:037, Section 2). If the gasifier waste is to be stored in a permitted landfill on site, the landfill permit will satisfy the regulatory groundwater protection requirements for the landfill area.

If the waste is not being land filled on site, a site specific groundwater protection plan must be utilized. The plan must be available for review upon request by providing a copy to be viewed at the facility, the DOW or a regional office or at a local public library. The GPP is not submitted to the Cabinet for review unless requested. If the DOW reviews the GPP and finds deficiencies, it will require corrections.

The GPP must follow a strict format and include required information. The DOW has prepared a guidance manual that explains the requirements, Groundwater Protection Plan Guidance (Revised February 2010).

- All activities conducted at the facility that require a groundwater protection plan must be described.
- Regular inspections must be conducted to confirm effective implementation of the GPP practices and the plan must describe inspection frequency and the inspection checklist.
- A description of how the Best Management Plan or practices will protect groundwater should be included.
- A description of secondary containment for ASTs, including the type of material (metal, concrete, asphalt, compacted clay or dirt) used to construct the floor and berms (sides) will be included.

2.7 Spill Prevention Control and Countermeasures Plan

Division of Waste Management

A Spill Prevention, Control and Countermeasures (SPCC) Plan will be required if the facility stores in excess of 42,000 gallons of petroleum product in underground tanks, or 1,320 gallons of petroleum product in containers of 55 gallons or larger (40 C.F.R. §112). The SPCC Plan must be certified by a registered professional engineer.

SPCC Plans must be updated every five years or within 6-months of a change in design, construction, operation or maintenance, and are kept on file at the facility. An SPCC Plan must have at least the following elements:

- A written description of any spills and corrective actions within the previous 12 months, and plans for prevention of future spills;
- Predictions of direction, flow rate, and quantity of discharge for each major type of failure where reasonable potential for equipment failure exists;
- Details of appropriate containment or diversionary structures used to prevent oil from reaching navigable waters;
- If installation of containment or diversionary structures is not practicable, a strong contingency plan and a written commitment to the expeditious control of oil discharges is required;
- Documentation that the facility design, construction, operation, and maintenance conforms with the requirements of 40 CFR 112.7 (e); and
- Certification by a PE and appropriate management approvals.

2.8 Permits Issued by Kentucky Division for Air Quality

Division for Air Quality

The Division for Air Quality (DAQ) is charged with regulating the emissions from industrial facilities through their permitting program.

All stationary sources emitting air pollutants above a minimum threshold found in 401 KAR 52 are required to obtain a construction/operating permit. The definition of "air contaminant or air pollutant" includes a broad range of substances. Consult Kentucky's air quality regulations (401 KAR Chapter 52- Permits, Registrations, and Prohibitory Rules) to determine which "family" of air pollutants may apply to your facility.

The emission determination for a facility is made based on calculating potential emissions over a 24-hour, 7-day, 52-week period. The total amount of emissions will determine the applicable regulatory category.

Construction can not begin until the air permit is issued from the DAQ and certain design decisions can impact the type of air permit and the length of time necessary for approval. The air permitting process will need to track the design process and begin as soon as practically applicable.

A coal gasification facility will require a state origin air permit or a Title V air permit, although the state has provided several options within those permitting avenues. The amount of emissions from the start-up boiler process and from material handling areas will likely determine which category of air permit is required.

The Cabinet has provided a Fact Sheet which helps the applicant analyze the type of permit that best meets its needs. See "Kentucky's Permitting/Registration Thresholds".

2.8.1 State Origin Air Permit

A state origin air permit (401 KAR 52:040) will be required if the potential to emit is:

- less than ten tons per year of a single hazardous air pollutant,
- less than 25 tons per year of combined hazardous air pollutants; and
- greater than or equal to 25 tons per year but less than 100 tons per year of a non-hazardous regulated air pollutants.

The DAQ guidance and permit forms may be accessed through the DAQ website. (See State Origin Air Permit Guidance and Forms Library and Related Documents).

Regulation 401 KAR 52:040 describes the application contents, which are to be submitted in triplicate. The Cabinet will determine administrative completeness within 60 days or the application is automatically deemed to be complete. Once the application is declared complete, the Cabinet then has a 60 day review period during which the permit must be issued or denied. As with all permit actions, the mandatory review clock is stopped by a reviewer's request for additional information, clarification or by a notice of deficiency.

Once issued, the permit is valid for ten years and a renewal application MUST be submitted at least 180 days prior to the expiration of the existing permit. The project must begin within 18 months of the issuance of the permit and the permit can be revoked if the project does not begin, is discontinued for a period of 18 months or is not completed in a reasonable amount of time. The developer can ask for an extension of this requirement.

A state origin air permit does not require public notice for issuance. The EPA can request to review a state origin air permit but this seldom occurs.

State Origin Air Permit Process Timeline

2.8.2 Conditional Major

The facility could accept limitations on their emissions to avoid major source status (Conditional Major - 401 KAR 52:030). For DAQ Procedures see Federally-Enforceable Permits for Non-Major Sources.

The reviewer again has 60 days to declare the application complete or request additional information. The regulations require that a draft permit be issued within 60 days after the application is deemed complete. Public notice of the draft permit is issued at that time and the comment period will last for 30 days. EPA has a 45 day period to review the draft permit. If public comments can be addressed without substantial changes to the draft permit and no public hearing is needed, the Cabinet will issue the final permit within 60 days after the EPA review period. If there are substantial changes following the public comment period, the cabinet will make the appropriate revisions and submit the application to the EPA for another 45 days review.

A new source that is conditional major will be allowed to construct and operate in compliance with the draft permit until the final permit is issued or denied.

Conditional Major (Air) Permit Process Timeline

2.8.3 Synthetic Minor

A developer can avoid PSD major source permitting by establishing an enforceable emission limit to keep the source's emissions below the Title I PSD major source threshold. To achieve this "synthetic minor" source status, the facility must:

- Compare their actual emissions to major source thresholds;
- Determine which sources need to have their operations limited and by what amount;

- Obtain any appropriate forms from the permitting authority; and

- Perform follow-up recordkeeping to assure compliance with the federally-enforceable limit.

The permit will create a set of terms and conditions by which the installation must abide. (See the guidance titled Federally-Enforceable Permits for Non-Major Sources.)

The synthetic minor source strategy has benefits and limitations. While this strategy reduces regulatory scrutiny and is less onerous than PSD permitting, it limits future expansion by requiring that emissions remain below the major source ceiling. This will require good, up-front planning to determine the potential for future expansion and the resulting consequences.

The permit review process for a synthetic minor is similar to a conditional major. The EPA will receive a copy of the public notice from the Cabinet and, if needed, copies of the draft permit. If no substantial changes are made in the permit as a result of comments, either from the public or the EPA, the Cabinet will issue a final permit within 60 days after the EPA review period. If there are substantial changes following the public comment period, the cabinet will make the appropriate revisions and submit the application to the EPA for another 45 days review.

If the facility files a synthetic minor application, construction can only begin after the final permit is issued.

Synthetic Minor (Air) Permit Process Timeline

2.8.4 Title V Air Permit

A Title V air permit will be required if the facility has the potential to emit ten tons or more per year of a single hazardous air pollutant, 25 tons or more per year of combined hazardous air pollutants; and 100 tons or more per year of a non-hazardous regulated air pollutant (401 KAR 52:020). (See Procedures for Issuing Title V Air Permits.)

While a Title V permit consolidates all requirements in one permit and allows more flexibility in future expansion, it also requires substantial recordkeeping and reporting, as well as potentially expensive monitoring requirements. The permit will undergo rigorous agency and public review of the application and draft permit.

The developer must use the appropriate sections of Form DEP 7007 to complete the application and include all the information needed to determine the applicable requirements and emission fees. (Review 7007 forms on the DEP website, Forms Library and Related Documents.) The Cabinet will compute the emissions fee under 401 KAR 50:038.

The reviewer will determine if the application is administratively complete within 60 days or request additional information. Once complete, the draft permit will be issued within 60 days. A public notice will be published with the draft permit, followed by a 30 day comment period. The facility should request that a public hearing be called with the public notice to stay on schedule. If there are no public comments, the Cabinet will issue a proposed permit which will be submitted to the EPA which has a 45 day review period. If no substantial changes are made in the permit as a result of comments, either from the public or the EPA, the Cabinet has up to 60 days to issue the permit following EPA review.

The permit can be revoked if the permitted action is not commenced within 18 months after the permit is issued, or is discontinued for a period of 18 months or more or is not completed within 18 months of the scheduled completion date.

The DAQ recognizes that complex construction projects like a gasification project may be phased and provides the following rules:

- each construction phase must begin within 18 months of the projected and approved commencement dates,
- the time between construction of approved phases will not count in determining that construction has been discontinued for 18 months or longer, and

- the cabinet may extend the time periods if the source shows good cause.

Important aspects of the application include the following:

- Emissions modeling and a Best Available Control Technology (BACT) assessment are required.

- Each emissions unit and points are described in sufficient detail to establish the basis for applicable requirements and emission fees.

- Air pollution control equipment and compliance monitoring devices or activities are described with emission rates and operating procedures adequate to determine or limit emissions are included. Stack height limitations, calculations, citations and descriptions of all applicable requirements, and the applicable test method for determining compliance with each are also included.

- Adequate information about proposed exemptions, permit conditions, alternate operating scenarios and emissions trading are included.

- A compliance schedule is included with remedial measures, checkpoints and scheduled completion dates, together with descriptions of monitoring, recordkeeping and reporting requirements, and test methods.

For a Title V air permit construction may not begin until the Cabinet issues a proposed permit.

Title V (Air) Permit Process Timeline

2.8.5 EPA Review for Air Permits

U.S. Environmental Protection Agency

Region 4

EPA has the option to review State Origin, Conditional Major and Synthetic Minor permits and is given copies of the Title V permits and allotted a 45 day review period prior to issuance of a final permit. To initiate EPA review, the Cabinet submits a statement describing the legal and factual basis for the draft permit conditions, including references to applicable statutory or regulatory provisions, together with copies of the permit, permit application and any other related information such as public comments.

The draft permit will become final at the end of the EPA's 45 day review in the case of a Title V permit, unless a substantial change is made in the permit following the public comment period or the EPA files an objection to the permit, in which case the appropriate revisions will be made and resubmitted for an additional 45 day review.

If the EPA objects to the issuance of a permit, they will file a statement of objection and supporting information within its 45 day review period. The cabinet will make the appropriate revisions and submit a new proposed permit or permit revision to the EPA within 90 days after the objection is filed or the EPA may issue or deny the permit.

3.0 FEDERAL PERMITS AND APPROVALS

A gasification facility may require approval by the Federal Energy Regulatory Commission (FERC) and the US Army Corps of Engineers (Corps), thereby requiring the National Environmental Policy Act (NEPA) process. NEPA requires federal agencies to assess, as part of their decision making process, the potential environmental impacts of their actions prior to the action. The NEPA process must be considered a part of federal permitting and its requirements are in addition to the actual permit requirements.

The NEPA process consists of an evaluation of the environmental effects of the federal undertaking, including any alternatives. There are three levels of analysis depending on whether or not an undertaking could significantly affect the environment. These three levels are categorical exclusion determination preparation of an environmental assessment/finding of no significant impact (EA/FONSI), and preparation of an environmental impact statement (EIS).

The EA evaluates the geographic, social, and environmental aspects of the project, and its impact on historical, cultural, parks, wetlands, and ecological areas. An EA explains the need for the proposed project, the alternatives considered, and the environmental impacts of each alternative and identifies agencies and persons consulted.

If the effects are not significant, then a Finding of No Significant Impact (FONSI) is issued and the project proceeds with no further NEPA review. The FONSI is made available to the public, but may not be put out for formal public review.
If a significant effect is identified, an Environmental Impact Statement (EIS) is needed unless the project can be revised to avoid significant impact. The recommended format for an EIS is found in Section 1502.10.

Public involvement is required if an EIS is prepared, including publication of a "notice of intent" (NOI) in the Federal Register, and notice to potentially concerned parties by letter, or newspaper article, etc. The agency then carries out "scoping", which determines the extent of the analytic work that will create the EIS and identifies substantive issues for further study.

The draft EIS is used to solicit comments on the proposed project from the public and other interested Federal agencies. Responses to comments received are included in the final EIS.

A public hearing may be requested by the public or called by the federal agency. The public is also informed of the decision maker's record of decision. Thus, a permit application requiring preparation of an EIS can involve five or more notices to the public during the review process.

Following completion of the process a final EIS is prepared and issued by the federal agency.

3.1 Federal Energy Regulatory Commission

Federal Energy Regulatory Commission (FERC)

The FERC regulates the interstate transmission of electricity, natural gas, and oil and reviews proposals to build interstate natural gas pipelines under section 7 of the Natural Gas Act. If the coal gasification facility will produce Synthetic Natural Gas (SNG) and transport the gas through a major interstate pipeline or a pipeline that will have an impact on the interstate transportation of gas, a FERC certification for the construction of the pipeline will be needed. If the coal gasification facility will produce electricity which will require interstate transmission, the FERC will be involved. Electric transmission lines are generally addressed within the section of this document that deals with local electrical utilities and the Regional Transmission Organization.

The FERC has issued a guidance manual for stakeholder involvement in the FERC gas pipeline permitting process: FERC Guidance Document.

FERC approval for an interstate gas pipeline may have the longest timeframe of any permit or approval for a gasification facility, due to their approach to NEPA requirements and the breadth of the review for the gas pipeline right-of-way.

The developer of the gas pipeline should use the NEPA pre-filing process, which identifies environmental issues before an EIS is prepared. To begin, the developer submits a written request seven to eight months prior to filing an application to FERC. The written request explains the project, lists the agencies involved and other the interested parties, and describes the plan for meeting NEPA requirements.

After the final EIS is received, FERC will approve or deny the FERC Order and implementation plan. Once a FERC order is entered for the construction of a gas pipeline the developer will submit the order in the local Circuit Court of the development site. Condemnation, if necessary, and construction, can then begin.

FERC Approval Process Timeline

3.2 U.S. Army Corps of Engineers

The U.S. Army Corps of Engineers (Corps) is responsible for regulating construction within navigable waters of the United States and discharges from dredge or fill activities within waters that drain into or are otherwise connected to navigable waters ("jurisdictional") of the United States, including special aquatic sites such as wetlands. A gasification project will likely include several activities that may impact jurisdictional waters. These activities include constructing a water intake, constructing a water discharge structure, constructing a barge loading facility, or impacting wetlands. Therefore, the developer will be required to obtain a permit from the Corps (33 U.S.C. § 1344) to conduct each of these activities.

There are two types of Corps permits, the individual permit and the nationwide permit. The Nationwide Permit is a general permit issued for similar activities that typically have temporary and relatively minor impact upon jurisdictional waters and the environment. It is not likely that a gasification facility will qualify for a NWP.

A gasification facility in Kentucky will be located within one of four Corps districts: Louisville, Huntington, Nashville, and Memphis (See Corps Districts in Kentucky).

3.2.1 Individual Corps Permit

The basic form of authorization used by Corps districts is the individual permit. Processing individual permits involves the evaluation of individual, project specific applications in three steps: pre-application consultation (for major projects), formal project review, and decision making. Information about the permitting process, including instructions for completing an application and a sample application can be accessed from the Corps web document "Applicant Information". An explanation of the permits and process required for discharges of dredged or fill material is found in a Corps guidance document.

The pre-application consultation provides for informal discussions about the project before the applicant begins preparing the application and can include meetings between the applicant, Corps district staff, interested resource agencies (Federal, state, or local), and sometimes the interested public. The purpose is to assess the viability of alternatives available to accomplish the project purpose, discuss measures for reducing the impacts of the project, and to inform the applicant of the factors the Corps must consider in its decision making process.

The Corps district will use a project manager system, where one individual is responsible for handling an application from receipt to final decision. The project manager prepares the public notices, evaluates the impacts of the project and all comments received, negotiates necessary modifications of the project if required, and drafts or oversees drafting of appropriate documentation to support a recommended permit decision. The permit decision document includes a discussion of the environmental impacts of the project, the findings of the public interest review process.

Within 15 days of receipt of an Application, the district engineer must determine that the application is complete, or determine that it is incomplete and notify the applicant of any deficiencies. A public notice will typically be issued within 15 calendar days of receipt of all required information following the completeness review. The comment period following the public notice will be a minimum of 15 calendar days and may be up to 30 calendar days.

Based upon comments received, citizen concern or potential impacts, the district engineer will also evaluate the application to determine the need for a public hearing or extend the comment period. The Corps may require the developer to provide additional information to address or clarify public concerns.

No permit is granted if the proposal is found to be contrary to the public interest. Public involvement is important in the Corps' administration of its regulatory program, primarily through the public notice and public hearing. Public hearings are called if a commenter requests one or if comments raise substantial issues which cannot be resolved informally and the Corps decision maker determines that information from such a hearing is needed to make a decision.

There are a series of external impacts which may affect the Corps permitting process. One is EPA's Section 404 or "veto" authority. EPA may prohibit or withdraw any disposal site if the EPA Administrator determines that discharges into the site will have unacceptable adverse effects on municipal water supplies, shellfish beds and fishery areas, wildlife, or recreational areas. This authority also carries with it the requirement for notice and opportunity for public hearing. EPA may invoke this authority at any time.

Individual state permitting and water quality certification requirements provide an additional form of external impact to the Corps regulatory program. Section 401 of the Clean Water Act requires state certification (See water certification section) or waiver of certification prior to issuance of a Section 404 permit.

In addition to these requirements, the Corps' implementing regulations require that the district engineers conduct additional evaluations on applications with potential for having an effect on a variety of special interests such as Indian reservation lands, historic properties, endangered species, and wild and scenic rivers.

Time frames discussed in this section reflect the Corps position on its permitting efforts. Although the Corps states that, on average, individual permit decisions should be made within two to three months from receipt of a complete application, staffing issues and permit application backlogs may significantly increase the time for a permit review. Applications requiring an EIS average approximately three years to process.

Corps Individual Permit Process Timeline

3.2.2 Corps Nationwide Permits

Nationwide permits are general permits issued by the Corps to authorize certain activities that have minimal adverse effects on the aquatic environment and generally comply with the related laws cited in 33 C.F.R. 320.3. Nationwide permits do not require public notice, since public comment was solicited prior to authorization of the nationwide permits. To qualify for coverage, the applicant must meet all general conditions and any conditions specific to the nationwide permit sought. Authorization of an activity under a Nationwide permit may be publicly challenged and delayed and may result in the applicant having to pursue an individual permit. The district engineer has the discretionary authority to require an individual permit if it is believed the project may significantly affect environmental and/or navigable resources. An explanation of the nationwide permits, general conditions and the specific conditions applicable to each is provided in 2007 Nationwide Permits.

It is unlikely that a gasification facility will have such a minimal impact that it will be able to qualify for a nationwide permit. The most likely nationwide permits applicable to a gasification facility are:

- NWP 7 – Outfall Structures and Associated Intake Structures
- NWP 13 – Bank Stabilization
- NWP 25 – Structural Discharges

Impacts from all activities for a project are aggregated and the facility cannot complete a separate specific nationwide permit for each construction activity of a gasification facility. **If the total disturbed area exceeds**

more than ½ acre, then an individual permit will be necessary.

If the project is eligible to use a nationwide permit, the developer must submit a pre-construction notification to the district engineer prior to commencing the activity (NWP General Condition 27). The pre-construction notice must be in writing and include:

- A description of the direct and indirect adverse environmental effects the project would cause; and
- A delineation of special aquatic sites and other waters of the United States on the project site.

The delineation can be made by the Corps or the applicant; however, utilizing the Corps will likely cause a delay. The pre-construction notice can be submitted using a letter or the standard application.

The district engineer must determine pre-construction notice completeness within 30 calendar days of receipt and can request additional information. The application will not be reviewed until complete. The engineer may request modifications or impose special conditions to mitigate any anticipated environmental impacts and avoid the need for an individual permit.

If the facility is required to submit a mitigation plan, it must be reviewed and approved by the Corps as part of the pre-construction notice completeness review. There is no specified review and approval time, but this can take an additional 90 to 180 calendar days and the notice is not deemed complete until the mitigation plan is approved.

The facility can not initiate construction until notified in writing by the district engineer that the activity may proceed under the nationwide permit (with any special conditions imposed); or 45 calendar days have passed since the pre-construction notice has been deemed complete and the Corps has not issued any written notice requiring an individual permit.

3.3 FAA Stack Height Obstructions

Any construction that will exceed 200 feet in height or potentially fall in the potential flight path or restricted airspace for a landing strip will be required to provide a notice of construction to the Federal Aviation Administration, describing the construction , its markings and lighting and requesting a determination that it will not interfere with aviation (14 C.F.R. §77).

To obtain a determination by the FAA, the developer must file a request for Obstruction Evaluation/Airport Airspace Analysis. This can be done electronically or by submitting a written application. Following submittal, the applicant will be notified if application must be made to the state as well. Guidance on marking and lighting is provided in Advisory Circular 70/7460-1K.

In Kentucky, the Kentucky Airport Zoning Commission must also approve construction. The Commission meets six times per year so timing of the application is crucial. Applications must be submitted at least a month before the scheduled meeting. Instructions and the appropriate forms can be found on the Commission's website.

FAA Obstruction Evaluation and KY Airport Zoning Approval Process Timeline

4.0 ADDITIONAL FEDERAL & STATE REQUIREMENTS

4.1 Emergency Planning and Community Right-to-Know Act (EPCRA)

The Emergency Planning and Community Right-to-Know Act (EPCRA) established requirements for Federal, state and local governments, Indian Tribes, and industry regarding emergency planning and "Community Right-to-Know" reporting on hazardous and toxic chemicals (42 C.F.R. §116).

According to EPCRA reporting requirements, the CTL/CTG facility will be required to report the storage, use and release of hazardous chemicals. The following link provides information relating to each potential requirement applicable to the facility. EPCRA information.

A gasification facility may maintain Extremely Hazardous Substances on-site in quantities greater than corresponding Threshold Planning Quantities and must cooperate in emergency plan preparation.

The local emergency planning committee facility must evaluate the need for resources necessary to develop, implement, and exercise the emergency plan, and make recommendations with respect to additional resources that may be required and the means for providing such additional resources.

Although compliance with EPCRA is not a permitting action, it will be required and will impact operational procedures, community interaction and compliance status.

4.2 Building Permits, Tank Installations and Safety Inspections

Kentucky Office of Housing, Buildings and Construction

4.2.1 Building Permit - Office of Housing, Buildings and Construction

Prior to construction, the developer of a gasification project must obtain approval of construction plans from the Division of Building Code Enforcement of the Kentucky Department of Housing, Buildings and Construction (HBC). The developer may also need to apply for local permits. Construction may not begin until plan review and approval has been completed. Frequently asked questions about the permitting and plan review process are at Building Code Enforcement FAQs.

Plan review is initiated by the use of the Submittal Forms which can be found on the DHBC website at Plan Submittal Forms. All building permits must conform to the Kentucky Building Code.

The initial filing with the Kentucky Division of Housing, Buildings and Construction includes the Plan Application Form and all applicable plans, drawings, surveys described in the Building Plan Application Guide.

The Kentucky Building Plan Review Fee Worksheet is used to determine the proper review fee (Fee Worksheet) and is based on the number and size of the buildings associated with the gasification facility. The fee sheet must be filed with the application and fees paid before construction can begin.

The review process of the submitted application is simple. The application and associated plans and information are examined for compliance with the Kentucky Building Code within a “reasonable time” after filing. If the building official is satisfied that the proposed work conforms to the requirements of this code and laws and ordinances, a permit will be issued. If there is a local building permitting agency, the letter from the Division will not suffice as a building permit. Rather, the local agency will issue a permit after receipt of the approval letter from Division of Housing, Buildings and Construction.

An application must be approved within 180 days or actively addressed by the applicant in that time or it will be considered abandoned. If questions or deficiencies are being addressed, the Division may grant extensions of time to avoid a finding of abandonment. Work must begin within 180 days of the permit issuance or it will expire.

4.2.2 License to Install Tanks - Hazardous Materials Section

The Hazardous Materials Section of the Division of Fire Prevention within the Kentucky Division of Housing, Buildings and Construction issues permits for the installation of both above ground storage tanks and underground storage tanks. The developer of a CTL/CTG facility will likely construct and operate large tank systems. Permit application forms to install above or underground tanks are found at Hazardous Materials Forms.

4.2.3 Safety Inspections - State Fire Marshall

The Division of Fire Prevention, Office of State Fire Marshall, enforces various codes to ensure that all public structures, facilities, and regulated vehicles are maintained in such a manner that all occupants and users of these facilities will be protected from fire, explosion, or other similar hazards.

The Office of the State Fire Marshall will review the plans and conduct a safety evaluation of all the gasification facility structures during and after construction to help identify problems and possible solutions to prevent any incidents. The application to the Department of Housing, Buildings, and Construction will provide the coordination with the State Fire Marshall’s office

5.0 ELECTRIC SERVICE REQUIREMENTS

The developer must work with the electric utility that serves the site to establish the feasibility and engineering studies necessary to initiate the level of service required for the facility. In Kentucky there are

- three electric utility companies that provide generation, transmission, and distribution services [American Electric Power (AEP)/Kentucky Power (KP), Duke Energy (Duke), and E.ON U.S. (locally Louisville Gas and Electric (LGE)/Kentucky Utilities (KU))],
- three electric utilities that provide generation and transmission services only [Big Rivers Electric Corporation (BREC), East Kentucky Power Cooperative (EKPC), and Tennessee Valley Authority (TVA)], and
- 24 electric utility companies that provide distribution services only (see attached map for companies and service territory boundaries).

A developer using AEP or EKPC electrical lines will work with PJM Interconnection to address the transmission of excess power from the facility. PJM Interconnection is a Regional Transmission Organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

If E.ON U.S. electrical lines will be used, the facility will work with South West Power Pool (SWPP) to address the transmission of start-up power and excess generated power. SWPP is an Independent Transmission Organization (ITO) under private contract with KU that administers and coordinates the sale of electricity on KU's behalf.

The TVA is a federal quasi-corporation that acts like a public power company. TVA supplies power in regions of southern Kentucky but they do not rely on a RTO to monitor the movement of their electricity. If a gasification facility will be in TVA's territory, then TVA will conduct the required RTO studies in-house.

If a project will use Jackson Purchase Energy Corporation, Kenergy Corporation, or Meade County RECC electrical lines, it must work with the applicable distribution company and BREC, the generation and transmission electric company, to address the transmission of start-up power and excess generation power.

5.1 Electric Utility Approval

A gasification facility will need a substantial power supply in order to begin operations. After initial startup, the facility may generate excess power beyond its own needs. Coordination with the local electric utility is required to initiate studies and planning to upgrade or place new electric lines, ensure adequate power is available for start up, and determine an adequate pathway to upload excess power.

The local electric utility will require an engineering feasibility study to be conducted for the gasification project. The facility and the local electric utility will enter into an agreement that outlines the scope of the study and describes objectives, project scope, budget, roles, systems, and timing.

A typical engineering study may cost $10,000 and take 60 days to complete. The utility bases its cost estimate on the engineering hours estimated to complete the study. The cost of the engineering study may be applied to the project as long as the customer completes the proposed project.

The study will develop a work plan which describes whether and how the electric utility can provide appropriate levels of electrical service and will identify whether additional right-of-way must be obtained, and whether transmission lines and substations must be developed to complete the project. Due to the fluctuating price and availability of steel, the electric utility may need an extended time to construct any necessary infrastructure for the project. The developer will be able to request temporary service during construction, using a form like that made available by AEP.

Temporary Service Form.
Electric Utility Approval Process Timeline

5.2 Regional Transmission Organization (RTO) Approval

If a facility generates excess electricity beyond its own needs, it will need to sell that power and upload it to the transmission grid. To do so, there must be capacity in the transmission system. The facility will have to work with the RTO or ITO when locating in the service territory of AEP/KP, Duke, and LGE/KU. If the facility is located in the service territory of any of the remaining 24 distribution companies, the facility will have to work with the distribution company and the associated generation/ transmission company BREC, EKPC, or TVA. Contact information for the primary RTO/ITOs in Kentucky is below.

PJM Interconnection
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497
Phone: 610-666-8980

Southwest Power Pool
415 North McKinley, #140 Plaza West
Little Rock, AR 72205
Phone: 810-614-3200

One of the core functions of PJM and SWPP is planning for interconnection to ensure electric supply adequacy. If a facility intends to place excess power into the grid, a PJM or SWPP study will be required.

An RTO interconnection study is made up of a feasibility phase, system impact phase, and facility phase. The scope of the study will be driven by the projected level of power expected to be available. If less than 20 megawatts (MW) will be sold on the open market, only certain sections of the RTO interconnection study must be performed.

To initiate the interconnection planning process, the developer contacts the appropriate RTO. The RTO will assign a Project Manager for each phase of the interconnection process who will work with the developer to complete the necessary steps for that project phase. Typically, a scoping meeting will be held to review the interconnection request and relevant existing studies. The parties will determine if the study will include a feasibility study or proceed directly to a system impact study, facility study, or an interconnection agreement.

The gasification facility must submit a completed Interconnection Request and an executed Feasibility Study Agreement and agree that the developer is responsible for the cost of the study. The submittal of all required data must be accompanied by a $10,000 study fee. The $10,000 study fee can be waived for generator requests under 20 MW in size. Overlap can be expected in the feasibility and system impact studies.

Unless otherwise agreed, simultaneously with the delivery of the Interconnection Feasibility Study to the developer, the utility will provide an Interconnection System Impact Study Agreement. The Interconnection System Impact Study Agreement, also commits the developer for the costs of the Interconnection System Impact Study, and requires a $50,000 deposit.

Once completed, the Interconnection System Impact Study is provided to the developer with an Interconnection Facilities Study Agreement, again committing the developer to bear the cost of this study. The required deposit will be $100,000.

If the planned facility will be located in AEP or EKPC territory, PJM is the coordinating RTO. Importantly, PJM accepts applications only twice a year, making timing of the submittal critically important. PJM membership is not required for the initial planning and construction phases of a generation or transmission interconnection project, but membership will be required prior to commercial operation. Membership may also be required in order to integrate operational and market infrastructure with PJM. PJM membership entails certain data requirements, operational and market coordination, committee support and financial obligations. Membership requires an initial $1,500 fee and an annual $5,000 fee.

If the developer plans a gasification project within KU service territory, the developer will coordinate with SWPP, as the RTO for this area. Unlike PJM, SWPP does not charge a membership fee for interconnection to the power system. Similarly, KU contracts with SWPP to oversee all their transmission services whereas AEP only interacts with PJM when co-generation is involved. And perhaps most importantly, SWPP accepts application requests on an on-going basis, rather than only twice a year.

If the developer plans a gasification project in one of the non-RTO areas the applicable member utilities and generation/transmission company will need to be contacted. Non-RTO member utilities will require similar feasibility, system input, and facility studies at the same approximate costs as the RTOs.

The following web link provides access to a series of guidance manuals from PJM for the RTO process.

PJM Manuals
RTO Approval Process Timeline

5.3 Kentucky State Board on Electric Generation and Transmission Siting Approval

A coal gasification facility may generate excess power which it will sell to the market, and may need to construct transmission lines to connect to the transmission grid. Merchant power plants and certain transmission lines (less than 1 mile in length and between 69kV and 138kV) are subject to approval by the Kentucky State Board on Electric Generation and Transmission Siting. If the line falls under the Kentucky Public Service Commission (PSC) jurisdiction, the developer will need to coordinate and support the local electric utility in the request for approval of the extension of transmission lines. Statutes governing the Kentucky PSC state that construction of a transmission line less than 1 mile in length and carrying less than 138kV is considered an ordinary extension of existing services and therefore not subject to PSC jurisdiction (807 KAR 5).

If the line capacity is at least 69kV but less than 138kV and is less than a mile in length, or if the gasification facility will be a merchant power plant capable of generating ten megawatts or more, the seven-member Siting Board will be convened to approve the construction of the project.

A guidance manual for Siting Board application procedures is helpful in determining what is required (Siting Board Procedures). The Siting Board is composed of the three PSC Commissioners, the Secretary of the Energy and Environment Cabinet, the Secretary of the Cabinet for Economic Development, and two ad hoc members, usually the Chair of the local planning commission or the County Judge and a resident of the county where the project is planned. The Siting Board considers environmental matters not covered by other permits, economic impacts and the impact of the proposed project on Kentucky's electric transmission grid.

The applicant starts the process by submitting a Notice of Intent at least 30 days prior to submitting the application. The notice is made public and must include the identity of the applicant, a brief description of the proposed facility and its location, the address of the local planning and zoning commission, if any, and a description of set backs. The 30 day period is used by the Siting Board to appoint ad hoc members and hire any consultants it may need for the application review.

The full application is filed at least 30 days after filing the NOI. The application must contain information about the project such as evidence that public notice has been made, a report on public involvement activities conducted by the applicant, a site assessment report containing a detailed description of the project and thorough analysis of the impacts to be considered by the Siting Board (visual impacts, traffic, property values, etc), a statement of compliance with any local zoning regulations and noise control ordinances, an analysis of the effects of the proposed facility on the electric transmission grid and an analysis of the economic impacts of the proposed facility on the community. The applicant must also disclose any previous history of environmental violations.

Within 30 days of the application filing, the Board can set an evidentiary hearing at which expert witness may be asked to testify. The Board usually convenes a local public hearing also. The applicant is required to provide proof of notice given to each party and the general public at least five days prior to each hearing.

807 KAR 5:100 establishes the application fees which are a function of the length of the line and the amount of capacity it will carry or the amount of nameplate generating capacity. The fee may be as much as $200,000.

Electric Transmission Siting Board Approval Process Timeline

Ideas for Better Stakeholder Involvement In the Interstate Natural Gas Pipeline Planning Pre-Filing Process

Industry, Agencies, Citizens, and FERC Staff

Prepared by:
FERC Staff
OEP Gas Outreach Team
December 2001

Table of Contents

Introduction

This document was developed by the Office of Energy Projects (OEP) Gas Outreach Team using the feedback and ideas collected from stakeholders at our pre-filing outreach seminars. It will be updated from time to time as needed, to incorporate new knowledge, techniques, or options that can help achieve consensus and a better application to the Federal Energy Regulatory Commission.

If you are viewing this document on the web site, click on the words that appear in blue to link to the glossary or to an appropriate web site. A full glossary also follows the document for further reference.

The concepts presented in this document are for discussion only, and do not necessarily represent the views of the Commission or its individual members.

Action Options Overview For Interstate Natural Gas Pipeline Siting

Early Involvement by All Stakeholders Can Develop Better Solutions

As a result of the comments and discussions at six Interstate Natural Gas Pipeline Facility Planning Seminars, the OEP Gas Outreach Team developed a set of Outreach Action Options for pipeline companies, agencies, citizens, and the FERC staff. The Action Options identify concepts, actions, and activities that will help each stakeholder group achieve more effective participation in the process of planning a natural gas pipeline.

For more information on how to be involved in a project from a landowner's perspective, see "An Interstate Natural Gas Pipeline on My Land? What Do I Need to Know?"

The U.S. Department of Transportation (DOT) is responsible for setting federal safety standards for natural gas pipelines and related facilities. The Office of Pipeline Safety at DOT is at www.dot.gov.

The objective is to provide the best possible guidance on different pre-filing techniques that can be used to address issues that are raised. Every pipeline project is different - its size, its location, the company's approach to working with stakeholders, the community's interest in participating, the agencies' experience with similar projects, etc. The goal of the Action Options is to offer some ideas that all stakeholders can customize for their needs.

Pipeline companies are encouraged to seek out greater involvement from the various groups early in the planning so those who are interested can participate in the decision-making process. Agencies and citizens are encouraged to get involved early and make their views known to the companies as soon as they learn about a potential project. The goal is to achieve consensus and settlements among the groups and the company about an acceptable project design. FERC staff has been asked to offer assistance early in the process to support all stakeholders. Earlier and more productive involvement will lead to better project designs and less contentious applications to FERC and other agencies.

Working together will pay off by helping to achieve agreements. Spending time up front will save time later. Consensus will be more easily achieved through implementing these ideas.

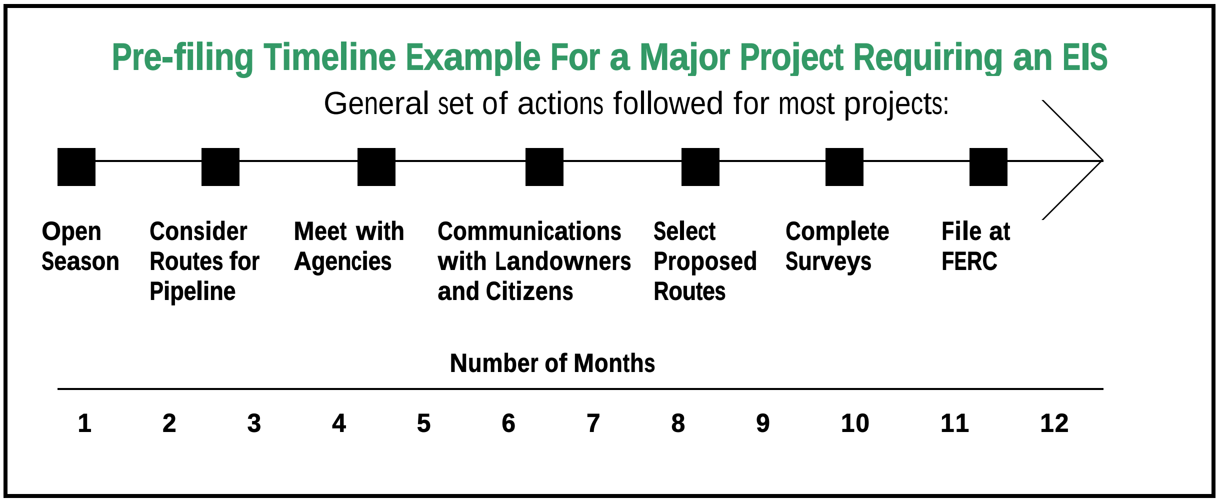
What All Stakeholders Need to Know

The Players

There are many different participants in the pipeline planning process.

- FERC - is charged by Congress with determining whether interstate natural gas transmission projects are in the public convenience and necessity.
- Pipeline Companies - These are the companies that build and operate interstate natural gas pipelines. They must justify the need, plan the route, and obtain numerous local, state and federal permits and clearances prior to construction.
- Federal, State and Local Agencies - The best way to find out who is involved from your local and state government is to call a local town official or a pipeline company representative and ask. Some typical agencies involved in the planning process include:
    - ⇒ **Local:** Town and County Councils, planning boards, zoning boards, and others
    - ⇒ **State:** Environmental agencies, historic preservation offices, fish and wildlife agencies, and others
    - ⇒ **Federal:** U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, U.S. Environmental Protection Agency, Bureau of Land Management and Forest Service

- Local citizens and landowners - have interests in whether the proposed natural gas line will impact their land or their community. Local citizens and landowners are encouraged to make their views known at any time in the process.



Pre-filing Timeline Example For a Major Project Requiring an EIS

General set of actions followed for most projects:

The Process

Generally, the formal process for evaluating a pipeline company's proposal to build an interstate natural gas pipeline begins when the company files an application with the FERC. The application includes maps showing the preferred route, the proposed facilities, the status of permit applications with local, state and federal agencies, affected landowners, and information on how the pipeline will affect the environment.

The FERC's review of the application and determination of need involves the balancing of the project's adverse impact against its benefits. The FERC's environmental analysis of the application under the National Environmental Policy Act of 1969 (NEPA) is part of that balancing. Public participation is a key element in FERC's environmental analysis.

The goal of the Action Options is to encourage participation in a process where all stakeholders have the opportunity to have input **before the development of the application**, so that issues are raised and addressed and solutions crafted and presented as part of the company's proposal.

Some Tips For All Stakeholders

- Ask other stakeholders how they want to be communicated with throughout this process.
- Agree up front on how stakeholders will be involved to set expectations at the start.
- Be patient—working together on a complex project requires understanding from all participants.
- Develop summary transcripts from meetings and share information with all stakeholders to keep the lines of communication open.
- Set up a process for what can be done if any stakeholder feels their needs are not being met. If everyone agrees on the process up front, there will be a way to address concerns.
- Remember that each stakeholder has control over their own actions and decisions. This is a voluntary process for all stakeholders.
- Formalize agreements in writing so everyone can be sure they understand and agree to what is decided.

NEPA IS...

- The National Environmental Policy Act of 1969 is legislation that requires federal agencies to consider the environmental impacts of their actions.
- It outlines a process for public input into the agencies' decision-making process.
- It requires that for major projects, a detailed environmental study be prepared, including the analysis of appropriate alternatives to the proposal.

Industry Action Options

Start Early, Be Pro-active, Involve Key Stakeholders

Natural gas pipeline companies and their consultants, contractors, and industry groups are the centerpiece of the pipeline siting process because they are the project planners and proponents. This group carries a large part of the responsibility to implement and coordinate the project activities that occur during the pre-filing time frame. There are a number of separate components to the actions that the company will need to take, including developing a company philosophy of commitment, ensuring agency participation, training company representatives and land agents, developing a public participation plan, collecting data, and having a plan for potential mitigation and compensation.

As part of its pre-filing groundwork the company should address internal and external planning and coordination issues. Pre-filing actions should be part of a coordinated plan, since they involve so many facets of a company and its consultants. Decisions on how to involve others should be made internally before they are implemented. It will also be important to train the project development team on the company philosophy and policy.

Dealing with agencies and citizens in a participatory decision-making process can help build consensus and resolve issues prior to filing. There will likely be some initial costs of time and money, but these up-front actions should result in quicker processing of an application and presentation of the record to the Commission for a decision.

Demonstrate Your Commitment to Public Involvement

- Companies should create a project team to interact with stakeholders. For large projects, the team should include environmental, engineering, and public relations professionals, in addition to other valuable experts. At least one company has formed a separate team specifically created for stakeholder outreach.
  - ⇒ Make sure the team is trained to perform the public involvement plan.
  - ⇒ Build the concept of public participation into training for all facets of the project development team.
- The company should decide early that it will be pro-active in getting agencies and land-

HAVE YOU:

- ✓ Asked the community how they'd like to receive information?
- ✓ Described the project in great detail to landowners?
- ✓ Explained to stakeholders how you will work with them in the pre-filing process?
- ✓ Told landowners about your company?
- ✓ Shared safety information?

owners involved in the process and the resolution of issues. Commit to being honest and open and following through in relationships with other stakeholders.

- As part of determining potential stakeholders for a project, identify and establish key contacts with:
  - ⇒ Governor(s) and federal, state, and local politicians
  - ⇒ Environmental agencies and groups
  - ⇒ Energy agencies/ PUCs
  - ⇒ FERC staff
  - ⇒ Non-governmental organizations
  - ⇒ Federal and state land managers
  - ⇒ Local distribution companies
  - ⇒ Landowner and community representatives
- Develop a positive attitude and company philosophy that includes a historical company mission perspective. Make sure employees at every level and in every division of the company understand the concept of public participation.
- When developing a public participation plan, consider how project announcements and first contacts will be made, and to whom meetings will be open. Be inclusive, get others involved early.
- Consider involving stakeholders in early efforts to develop the route.
- Be prepared to explain the need for the project to agencies and landowners. Explain the support the company has for the project at opportunities such as meetings and open houses, etc. Explain supply/demand and get help and/or information from public utility commissions (PUCs), the Energy Information Administration (EIA), independent system operators (ISOs) and local entities on regional issues important to landowners.
- In addition to sharing information about the benefits of a pipeline, commit to being open about the down sides too. The public will respect honesty and it may prevent future misunderstandings.

Maintain Strong, Open Channels of Communication with Agencies

- Develop a multifaceted, grass-roots strategy for announcing the project to federal, state, and local agencies (and to landowners), which maximizes their opportunity for input into identifying potential issues and their resolution.

Involve stakeholders early and share information.

- Describe the time table for the project and try to get agency contacts to commit to have their staffs work at the requested pace.

- Be clear about when and how landowners and agencies can best contribute to the planning process.

- Set up big picture meetings/briefings with agency policy staffs, but be sure to also hold detailed working sessions with technical staff.

  - ⇒ Conduct field visits to help get a better understanding of an issue.
  - ⇒ Consider the source of the information and whether it is really representative of the agency's assessment.

- Explore the potential for team permitting options among agencies. The value of early coordination and notification of problems is high.

- Tell federal agencies, local and regional officials, and state agencies about the project as early as possible, with as much detailed information as is available, so that they may tell citizens when they call. Ensure that the information is updated when events or schedules change. Consider developing materials that agencies can provide to interested stakeholders and develop a website with the latest information.

> The value of early coordination and notification of problems is high.

- When and if limited resources prevent agencies from timely responses or actions, consider funding third-party contractors to work for them.

- Provide the FERC staff with accurate, advanced project information in as much detail as possible so that they can help coordinate outreach to other agencies.

Train Company Representatives and Land Agents

- Develop specific training for company representatives and land agents on the importance of company philosophy and their role in establishing good communication with landowners and continuing it. Landowners want to deal with someone who is personable, honest, and respectful.

  - ⇒ Land agents are either building or hurting the reputation of the company with all affected parties they meet.
  - ⇒ Landowner trust will be based in part on experience with the industry as a whole.
  - ⇒ Consider using local land agents or hiring local assistance to familiarize out-of-town land agents with local culture and geography.

- Train land agents in dealing with people and on the company's public participation plan.

    - ⇒ When people are upset, find out what people are upset about.
    - ⇒ Land agents should be willing to put commitments in writing or not make them.

Land agents are your representatives to the community.

Plan for Public Stakeholder Input Throughout the Process

- Make a commitment to involve affected landowners and other interested citizens in the project planning process. Inform them, listen to, and record landowner's ideas and knowledge of the area and environment. Make sure communication is clear and easily understandable, and respond to them constructively and with empathy.

    - ⇒ Ask the community how they would like to be communicated with. What works in one area may not work in another.
    - ⇒ Develop a public participation plan early, share it with landowners, and ask for comments and suggestions.
    - ⇒ Try to have one consistent contact person that landowners can call, and make sure that person is clearly identified to the public. Provide the land agent's name and number and also the supervisor at the company or a company hotline to call.
    - ⇒ Bear in mind first contact issues and their potential sensitivity to landowners - a call, a letter, a visit? Consider issuing a public notice in the local newspaper or on other media (television, radio) before contacting landowners for a survey so that landowners have some awareness of the project before they are first contacted.
    - ⇒ Post information and updates on town bulletin boards and other public places.
    - ⇒ Ask town officials for help contacting local stakeholders so it can be determined whether or not everyone impacted by the project has been contacted.
    - ⇒ Share where the company gets its information and what resources the company relies upon.
    - ⇒ Give people time to react to requests, documents etc. Don't expect overnight feedback.
    - ⇒ During the process, setup a feedback system so citizens know when they will get answers to their questions. Put answers to general questions on a web site or other public place so all citizens can see the information.
    - ⇒ Stay away from industry jargon: use language carefully and be aware of how the public perceives the company at all times. Using words like "marketing" in public settings can give the company a negative image because the word has different meanings to different people.
    - ⇒ Understand stakeholders' knowledge and background.
    - ⇒ Consider establishing an ombudsman for neutrality in information and contacts.
    - ⇒ Consider funding of studies requested by stakeholders.

Project Announcements and Ongoing Information Collection

- When announcing the project, be specific and thorough—carefully spell out the process and timeline for other stakeholders.

- When announcing the project, consider the most effective meeting types. Again, ask stakeholders how they want to be communicated with.

  - ⇒ Do they prefer open houses, or one-on-one meetings, or a letter first? Should the initial contact be formal or informal?
  - ⇒ Consider meeting locations and times. For example, in an agricultural area, don't hold a meeting in the planting/harvest season; or don't hold a meeting on a religious holiday; etc.
  - ⇒ Have qualified engineers and technical staff available to answer safety and design questions, perhaps with a sample piece of pipeline, to describe how it is designed and operated.

- For an open house, notify all stakeholders in the study corridor. Perhaps present a slide show on pipeline construction and other general issues so that people unfamiliar with pipeline siting and construction can get a clear idea of what is proposed.

  - ⇒ Describe the size and types of equipment that would be used.
  - ⇒ Ensure all documents are accurate and consistent. Avoid giving conflicting information to stakeholders.

> When announcing the project, consider the most effective meeting.

- Distribute the following information, whether in pamphlet-form or by other means:

  - ⇒ A general biography of the company,
  - ⇒ General information on environmental and other benefits of natural gas,
  - ⇒ Discussion of today's energy market and the need for expanded infrastructure,
  - ⇒ FERC background information,
  - ⇒ Discussion of pre-filing activities,
  - ⇒ Post-filing review process,
  - ⇒ Construction information,
  - ⇒ Safety information, plans for safety training and the company's past safety record, and
  - ⇒ Intended time frame for completing various activities (a project time line).

- Share the pre-filing process with landowners in detail so that they can better understand the steps and decide how to get involved.

- Suggest unbiased sources (academics, web sites, government statistics) that are not affiliated with the company so that stakeholders can get information that is trustworthy in their eyes. Avoid using the term “proprietary information” because it can raise suspicions and create distrust.

- Make sure that all of the information that is used and shared with the public (including maps, studies, etc) is current and up-to-date.

- Follow up on outstanding questions and let people know how the answers will be communicated.

- Conduct post-project interviews or evaluations with key stakeholders to make future improvements.

Make Route Development and Data Collection Easy and Understandable

Share the pre-filing process with landowners in detail.

The stage of the process where surveys are performed, data collected and routes proposed may be the most confusing and complicated for many stakeholders. When it’s time to do the detailed route planning, make sure the landowner knows what to expect and has given permission to proceed with the survey(s). Survey permission forms should be readable with full disclosure of survey requirements.

- ⇒ What does survey permission mean? Recognize and state clearly that landowner concurrence to allow a survey is not approval of a right-of-way. Know the difference.
- ⇒ Explain the types of surveys (crew size, survey methods).
- ⇒ Describe the work to be done (such as: is tree cutting or clearing required? Will test holes be dug?).
- ⇒ Ensure the survey corridor is wide enough to accommodate route variations.
- ⇒ Describe alternative routes the company considered in addition to the proposed route.

Explain Mitigation, Compensation and Benefits in Layman’s Terms

- Many landowners are unfamiliar with the rules, process, and procedure of how a right-of-way payment is made. So, explain the compensation/payment method to landowners.

  - ⇒ Explain the typical procedures which the landowner can expect will be used.
  - ⇒ Explain procedures and specifics around payments for easements - how are they determined?
  - ⇒ Share information about additional damage payment(s) made after construction
  - ⇒ Provide options of what a landowner could request as compensation.

- Explain the energy benefits which will result from the project, or other benefits which could be locally significant.
  - ⇒ Develop a benefits plan and educate stakeholders about local benefits of the project (i.e. payments to landowners, local tax payments, etc).
  - ⇒ If the landowner requests "side jobs," explain what is or is not allowed and how the job might be performed for the landowner.

- Since practices vary among different pipelines, it is important to be up-front about the company's usual custom and whether or not it involves monetary compensation. If any funding to aid public participation is available, tell stakeholders early.

Conclusion

The proper preparation and stakeholder involvement in the pre-filing process can make the entire process easier, quicker, and ultimately less expensive. The company's reputation with the community and involved agencies will benefit from a well-devised, well-executed participation plan.

Agency Action Options

Coordinate to Address Multiple Oversight Responsibilities

Numerous agencies (federal, state and local) have a role in natural gas facility siting. All serve the public and may have overlapping responsibilities. Agencies' focus on management and regulatory requirements span a very wide spectrum of cultural, natural, economic, educational, political, and other resource interests. As a result, different agencies may have conflicting priorities or responsibilities due to their unique focus and or function. What is ideal for one agency may be detrimental to another. The challenge here is to identify what is needed to avoid or at least minimize obstacles to providing coordination and service, and how to achieve better results early in the facility planning process. There are several steps to coordination, including addressing project issues early, discussing joint participation, defining agency needs early, and addressing mitigation needs as soon as possible.

Address Project Issues/Concerns Early for Better Results

With many agencies and potential overlapping needs, it is important to get your agency's interests into the mix early so your role is clearly defined and understood from the beginning. Some of the things agencies can do upon getting an initial contact from a company include the following.

- Know what project components will involve your agency.
- Get support from agency management to commit resources for early involvement
- Determine the lead federal agency (usually FERC) and lead state agency, if one, and provide a key agency contact to ask and answer questions early.
- Establish coordination and early participation procedures among agencies.
- Consider attending public meetings in order to provide your agency's perspective and explain your role in the process.

HAVE YOU:

- ✓ Identified where your agency should get involved?
- ✓ Gotten support from agency management?
- ✓ Identified key issues and information needs
- ✓ Decided on coordination procedures?
- ✓ Attended public meetings?

Consider Multiple Agency Coordination and Joint Participation

Coordination with other agencies can reduce timing for reviews and approvals.

- Encourage team permitting to improve your agency's internal and external processes. Team permitting could reduce redundant review and provide information concurrently to all interested parties.
- Federal agencies should coordinate regulatory review and approvals at the federal level early.
- State agencies should coordinate regulatory review and approvals at the state and local level early.
- Determine whether your agency has public notification rules and/or needs to hold public meetings. Consider whether another agency's meeting could fulfill the requirements. Agencies that must involve the affected public and stakeholders before making their recommendations and decisions.
- Even if your agency cannot commit to early involvement, know where to get information and stay informed.
- Consider creating a document that shows how agencies work with other agencies so citizens know how to work with the system.
- Consider creating an agency forum for discussion and resolution of common issues.
- If resources prevent agencies from timely responses or actions, consider third-party funding by the project proponent to assist the agency.
- Ensure that decision-makers and required technical staff are involved early in the process so that accurate issues and needs are reflected early and decisions can be made more accurately and quickly.

Define Agency Information Needs and Timing Requirements Early

It is very important to identify information and timing requirements as early in the process as possible. When issues about the project, the process, and likely conflicts or potential outcomes are defined and acted on early, the process can go more smoothly and efficiently.

- Be clear about what information your agency needs and when you need it—have your requirements published clearly. Examples may be specific route surveys, survey results, landowner information (approved or denied survey access, etc.), and timing of when all remaining information must be submitted.

Identify "show-stoppers" as early as possible.

- Identify where and when decisions will be made and who will make them.

- If there are any "show stoppers" identify them as soon as possible. Examples: If state/local agency code/regulations have siting guidelines or requirements that conflict with FERC's routing criteria, or would require use of established "utility corridors" that are not conducive to a proposed project's end points.

- Agencies should give early and honest feedback on route alternatives. Make sure you supply whatever information you have.

- Agencies should identify any known cumulative effects (both beneficial and adverse impacts) and any growth that will occur in the project area. These should include location and timing information about any known development or other projects in the vicinity of the proposed pipeline.

Address Mitigation Needs As Soon As Possible

If resource impacts are unavoidable, but can be mitigated or otherwise compensated for, identify potential options which satisfy your concerns, as early as possible.

- Identify if compensation will be required.

- Explain who is responsible for developing mitigation plans.

Conclusion

Although different agencies can often have conflicting priorities and responsibilities, early and effective coordination can help prevent obstacles. It is important to know how to get information and to decide early on how different federal, state, and local agencies will work together in the most effective manner.

Citizen Action Options

Citizens Have a Unique Role: Take Advantage of Your Opportunity to Participate

Citizens and landowners are unique in the natural gas pipeline siting process for several reasons. While the pipeline company is proposing the action, and the government agencies are actively involved in the permitting process, citizens are often passively swept into the process. While the pipeline companies and the agencies participate in the process in the context of doing their jobs, the citizens not only must take time off from their jobs to participate, but their stake in the outcome may be more personal; the project affects their own property and/or community.

The challenge for citizens is to develop resources that enable active engagement in the process, objective application of the process, easier identification of direct or indirect project benefits, and greater access to information. In order to be involved in the most productive way, citizens should get involved early and make an effort to understand the process.

Get Involved Early and Stay Informed

Every pipeline company and every natural gas pipeline siting project is different. Projects that are large or new take longer to plan than smaller expansions of existing systems. The difference can depend on geography, the company's culture and the type of community that may be impacted by the siting process. Getting involved early and staying informed is a citizen's best strategy for ensuring that their needs are met and their questions answered.

♦ As soon as you can become involved, seek out information pro-actively; don't wait for it to come to you. If you wait, you could lose an opportunity.

  ⇒ Constructive participation will get you more answers and information. Participate from a foundation of knowledge and fact rather than emotion and rumors.

HAVE YOU:

- ✓ Identified Company contacts?
- ✓ Learned about the siting process?
- ✓ Checked the pipeline company's web site?
- ✓ Given feedback on how the company or agencies can improve communication?

- Let the company know if you are interested in participating in the planning stage (where the route is determined) and not just the permitting stage (where the route is reviewed by regulators and agencies).

SOME SOURCES OF INFORMATION INCLUDE:

- FERC Regulations
  18CFR380
- FERC Landowner Notification Rule
  18CFR157.6(D)
- FERC Website
  http://www.ferc.gov
- Interstate Natural Gas Association of America
  www.ingaa.org
- Companies' Websites
  http://www.ferc.gov/industries/gas/gen-info/pipecomp.asp

- Recognize what information the companies are obligated to provide and what information is not available.

  - ⇒ Ask questions and follow through until they are answered to your satisfaction.
  - ⇒ Although you should be prepared to wait for answers, you should also balance that with being assertive when it comes to asking for information you should have.
  - ⇒ Lots of information is on web sites (companies, agencies); make use of it.
  - ⇒ See the Industry Action Options for information about what resources should be made available to citizens; ask about them.
  - ⇒ Make sure you get the project manager's name and contact information so that you have someone to call if you have questions.

- Understand that your active participation in a company's project can add value. Regardless of your opinion, it is in the company's best interest to work with you rather than against you.

  - ⇒ Decide if you want to be involved in decisions regarding routing and/or construction impact mitigation.
  - ⇒ When you send in comments to FERC, also send a copy to the company so they are immediately aware of your opinions.

- Explore whether your local municipality, county, or citizen organization will represent you as a group.

- Know the name and phone number of the company land agent's supervisor or the number of the company/landowner hotline. Don't hesitate to call if you feel you are not getting answers or if you think you are being treated unfairly; the company wants to know.

- Consider asking the company if any aid to public participation such as reimbursement for time and expenses is offered so you can be involved in the process. Every company has a different approach to how to handle this so don't be surprised if the company _you are working with tells you it is against their policy to provide compensation for your time or expenses.

Your participation can add valuable project information to the pipeline company's planning process.

Do Your Homework to Ensure Your Involvement is Productive

The process of siting natural gas pipelines is complicated and involves lots of participants and details. The following can help you be sure you are informed about the process and how you can become a partner in that process.

Know the Participants

- Understand the mission and business plan of the company proposing the project.
    - ⇒ Check their web site and public mailings.
- Understand the role and mission of the FERC and its processes.
    - ⇒ Check the FERC web site at http://www.ferc.gov/for-citizens/my-rights/citizen-guides/citz-guide-gas.pdf
- Understand the role of federal, state, and local agencies.
- Understand how your first tier local government can work for you. Your local government or community may be able to be your advocate.

Know the Process

- Understand the concepts of eminent domain, federal preemption, and public convenience and necessity.
- Understand the process of the National Environmental Policy Act of 1969 (NEPA). It is a statute that requires a federal agency to be aware of the environmental impacts of its decisions.
- Understand that the pipeline company will respect you for your honesty, just as you respect them for theirs.
- Understand that the regulatory review and approval process may not move as quickly as

the agencies involved to ensure a smoother process.

- Find out what survey permission is and what survey companies do (e.g. number of days, extent of work, etc). Be informed.

Becoming a Partner

- Determine whether there are, or could be, direct or indirect benefits of the project to your community and to you personally.
- Your knowledge can help accomplish the goals of the company in a way that meets your needs at the same time.
- Allowing surveys is not the same as granting a construction easement. Consider allowing the company to complete its surveys on your property as they may document environmental or engineering constraints if they exist. You may seek the advice of counsel if you are concerned.
- Improve informational resources. If FERC's or a pipeline company's landowner brochure doesn't meet your needs, tell them and suggest ways to improve them.

TYPICAL TYPES OF SURVEYS INCLUDE:

- Civil surveys,
- Geotechnical surveys,
- Cultural resource surveys,
- Wetland delineation surveys, and
- Threatened and endangered species surveys.

Some types, (especially geotechnical and cultural resource surveys), typically require localized excavations at predetermined intervals.

All surveys require that the surveyor have access to the land. Once access is granted, various surveyors may visit the property intermittently over a period of time.

Conclusion

There are ways for interested citizens to get involved in the pre-filing stages of natural gas pipelines that could affect their community. It is important that all stakeholder groups work together to ensure that citizens are actively engaged in the process, understand direct and indirect project benefits, and have greater access to information. Early involvement and better understanding will increase public participation and allows citizens to make their views known.

FERC Staff Action Options

FERC'S Role as the Lead Agency

There are many questions regarding FERC's role in siting natural gas pipeline facilities and how FERC's process is connected to those at other agencies, particularly state agencies. Landowners clearly look to FERC to provide more information than is currently available. Further, natural gas companies look for additional help from FERC to coordinate the efforts of all the other permitting authorities. There are several action options that can address requests for greater staff participation and other resources to aid the various stakeholders in the planning process. Options include: making an effort to keep information up-to-date, offering training to share information, and committing to get involved in the process early.

Commitment to Providing Up-to-Date Information

- The FERC web site was revised in the spring of 2001 and represents a marked improvement in appearance and the organization of information. Although it is more user friendly and it's easier to find the information you need, no new functionality was built into the latest release. FERC is considering further upgrades. Comments received at the seminars regarding the web site included requests for:
    - ⇒ Summary and status information for major projects. The summaries could also include links to the applicants' project web site.
    - ⇒ Criteria, requirements, and documentation for getting approval for the NEPA pre-filing process.
    - ⇒ A "home" for pre-filing (pre-docket number) project information.
    - ⇒ State-by-state links to relevant agencies so landowners can use the FERC site to get local info.
    - ⇒ A guide on how to contact FERC and ask that they get involved in a project.
    - ⇒ A landowner chat room where subject matter experts could respond to questions.
    - ⇒ Other specific requests to solve problems such as retrieving filed information from the RIMS system.
    - ⇒ Data on future projects.
    - ⇒ A list of contacts if people have further questions.

> The FERC staff can become involved in projects during the pre-filing stage.

- FERC staff and/or other resource agencies (the Energy Information Administration, PUCs) should work to generate information about the big-picture market for natural gas and the need for natural gas on a regional basis that could be presented to various stakeholder groups.

- During the decision-making process, FERC should be sensitive to the difference between survey permission and landowner support of a project.

- FERC should enhance the existing brochure "An Interstate Natural Gas Pipeline on My Land? What Do I Need to Know?" to include information such as:

  - ⇒ The availability of information on the FERC's web site.
  - ⇒ Resources available to landowners (e.g., INGAA web site).
  - ⇒ Materials that companies are required to provide to landowners and others under the Landowner Notification Rule - when it is provided and to whom.
  - ⇒ What types of routing changes and landowner benefits in easement agreements can be negotiated without FERC approval, as FERC will not be involved in easement negotiations.
  - ⇒ Clarification on how a landowner can become an intervenor.

- FERC should conduct exit interviews with landowners after each project that implements pre-filing involvement to better understand where problems were and how those problems were solved. Debriefings on completed projects could be used to determine improvements to future projects.

- FERC should prepare a scoping summary to address issues raised during scoping.

- Consider establishing a single point of contact to answer questions.

Training to Improve the Process

FERC will offer training (mainly for industry and consultants) on Revised Regulations for Environmental Reports (Minimum Environmental Filing Requirements). FERC is currently planning a series of training sessions; please see www.ferc.gov for session dates, locations, and other details. Training will also be offered on Environmental Compliance. FERC can also use these training sessions to provide information to professional participants and to disseminate information on new methods and protocols that improve the NEPA process.

A Commitment to Early Involvement by FERC Staff

- Improve programmatic coordination between the FERC and other permitting agencies to expedite natural gas projects.

  - ⇒ FERC can make staff available to attend agency coordination meetings either before or after the filing of an application (subject to staffing limitations).
  - ⇒ If needed, help develop interagency or project-related Memoranda of Understanding between FERC and interested agencies to establish jurisdiction and responsibilities.

By getting involved early, FERC can help coordinate agency and citizen participation.

- FERC could help achieve consensus in route planning and issue identification and resolution at the earliest possible point (i.e., before the filing of an application). FERC is currently in the process of initiating pre-filing environmental reviews. It is likely that FERC's involvement in each project will be slightly different depending on the case-specific circumstances. Typically the goal would be to issue a draft EIS very shortly after an application is filed. Adequate time should be allotted in the pre-filing phase to conduct scoping meetings, field surveys, and to compile the reports that are required to support the coordinated review by agencies, FERC, and third-party consultants.

- As the lead federal agency, FERC could advise other agencies of their role in the pre-filing application process.

- FERC should consider expanding its process to include giving responses to all levels of government officials. This response policy would help pipelines in addressing issues at the local level.

Conclusion

FERC could provide more information to stakeholders and coordinate efforts among agencies. FERC's early involvement should improve communication between stakeholders and could expedite the process.

Glossary

Construction easement

The area of land, or "footprint" that is disturbed or used for construction of the pipeline. This area is typically larger than the "permanent easement" and includes extra work areas for activities such as equipment staging, topsoil storage, stream and road crossings, and right-of-way access during construction.

Construction impact mitigation

Those measures that are implemented in order to reduce or undo the potential damages incurred during pipeline construction such as soil erosion on slopes that have been cleared and graded. In this example, water bars or slope breakers could be installed across the slope to minimize erosion caused by precipitation and the resultant siltation of nearby streams. State and Federal agencies often attach many construction mitigation requirements to their licenses and permits.

Draft EIS

A draft Environmental Impact Statement issued by the lead federal agency for a 45-day comment period.

Easement agreements

The legal document, signed by both the pipeline company official and the landowner, that specifies the route, work areas, amount and method of payment, if any, and other terms such as restrictions on the use of the land, and possible future expansions of the pipeline.

Easement and damage payments

Payments made by the pipeline company to the landowner or land-managing agency for the easement or damages resulting from pipeline construction. Damage payments, if necessary, would be in addition to standard payments for the right-of-way easement.

Easement negotiations

Those discussions between pipeline-company official and landowner about the specific terms of the easement that may or may not result in a signed agreement. These discussions are usually conducted by land agents representing the pipeline companies.

Eminent domain

The right of a government to seize private property for public use in exchange for payment of fair market value.

Energy Information Administration (EIA)

The Energy Information Administration (EIA), created by Congress in 1977, is a statistical agency of the U.S. Department of Energy. They provide policy-independent data, forecasts, and analyses to promote sound policy making, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment.

Environmental review

From the Federal perspective, implementing the independent review, agency consultations, and scoping out of issues that are part of administering the mandates of the National Environmental Policy Act (NEPA). Depending on the project’s size, complexity and level of controversy, this review may take between three months to over one year.

Federal preemption

With respect to natural gas pipeline systems under the jurisdiction of the FERC, this broad legal concept means that Federal authority supersedes the state or local authority.

Formal certificate review

The formal review of an application under the Natural Gas Act which considers, in addition to environmental issues, rates, markets, financing, and other business issues.

Independent System Operator (ISO)

Organizations that manage the transmission portion (as opposed to the generation portion) of the electric industry.

Intervenor

Someone who wishes to participate in a proceeding and therefore files a petition to intervene with the Commission for a particular case. In their filing, an intervenor may additionally state whether or not they wish to protest the application and whether or not they seek a formal hearing on the application.

Land agents

Those representatives of the pipeline companies who are dispatched to acquire the right-of-way for the proposed pipeline project.

Lead federal agency

When more than one federal agency has permitting authority for a project, the agencies often designate a lead Federal agency to supervise the preparation of the EA or EIS. The FERC is frequently the lead Federal agency for natural gas pipeline projects.

Open season

A process in which a pipeline company solicits market interest for new pipeline transportation services. This is done as part of the pipeline company's planning process to help it determine the economic feasibility for a project.

Pre-filing time frame

The period of time before an application is filed at the FERC.

Public convenience and necessity

Synonymous with "for the good of the general public". Generally, if the Commission determines that there is sufficient need for a project after the consideration of all relevant factors, then it is determined to be in the public convenience and necessity and, it will be processed and issued a "certificate of public convenience and necessity" or license. These "certificates" carry with them the power of eminent domain.

RIMS

The Record Information Management System (RIMS) is the database where case-specific information is stored electronically. It is accessed via the Internet at www.ferc.gov.

Route variation

Relatively small deviations from the proposed route that are meant to avoid some environmentally sensitive area. Route variations usually depart from and then rejoin the proposed route within a short distance.

Scoping

In the context of NEPA, scoping is the process of asking the public and other agencies to identify any environmental issues that should be considered in the environmental analysis of the pipeline project.

Side jobs

Activities which are not related to work required for the pipeline construction but which the pipeline company may be willing to do for a landowner as part of the easement negotiation.

Survey

Typical types of surveys include civil surveys, geotechnical surveys, cultural resource surveys, wetland delineation surveys, and threatened and endangered species surveys. Some types, especially geotechnical and cultural resource surveys, typically involve localized excavation at predetermined intervals in order to collect the desired data. The other types of surveys usually only involve walking the pipeline right-of-way, taking measurements and observations and may involve taking small samples such as soil and plant samples. All surveys require that the surveyor have access to the land being surveyed. Survey permission forms may be used to document landowner agreement to allow access. Once access to the land is granted by the landowner, surveyors may visit the property intermittently over a period of time.

Team permitting

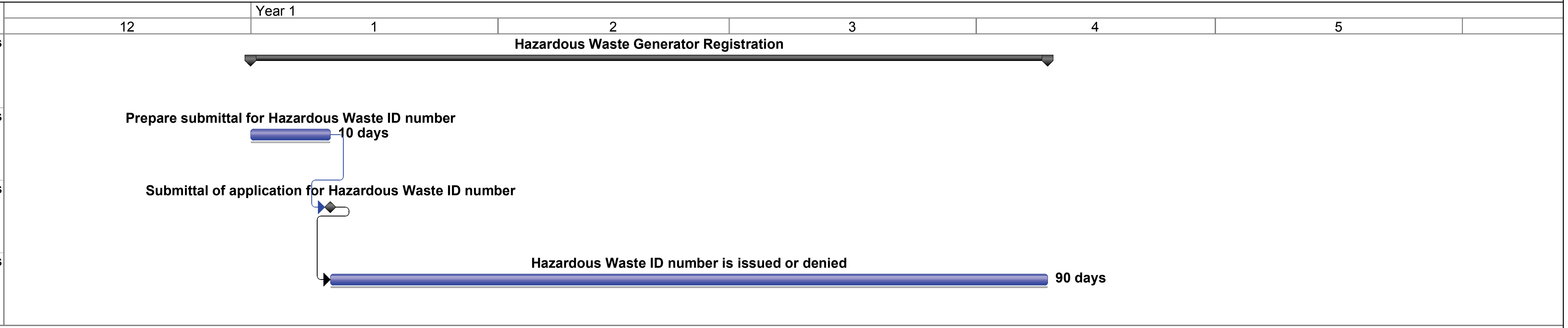
An approach that some states have adopted to issuing the many various environmental permits for a particular project whereby the agencies involved coordinate with each other (and the applicant, public, and cooperating agencies) and issue all their respective permits in one action.

Test holes

Small excavations or borings performed in the process of surveys such as cultural resource surveys or geotechnical surveys.

Figure 2.1 - KENTUCKY HAZARDOUS WASTE GENERATOR REGISTRATION PROCESS

ID	Task Name	Duration
1	**1 Hazardous Waste Generator Registration**	**100 days**
2	1.1 Prepare submittal for Hazardous Waste ID number	10 days
3	1.2 Submittal of application for Hazardous Waste ID number	0 days
4	1.3 Hazardous Waste ID number is issued or denied	90 days



Project: Hazardous Waste
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	┆	Milestone	◆	Project Summary	▬	External Milestone	◆		

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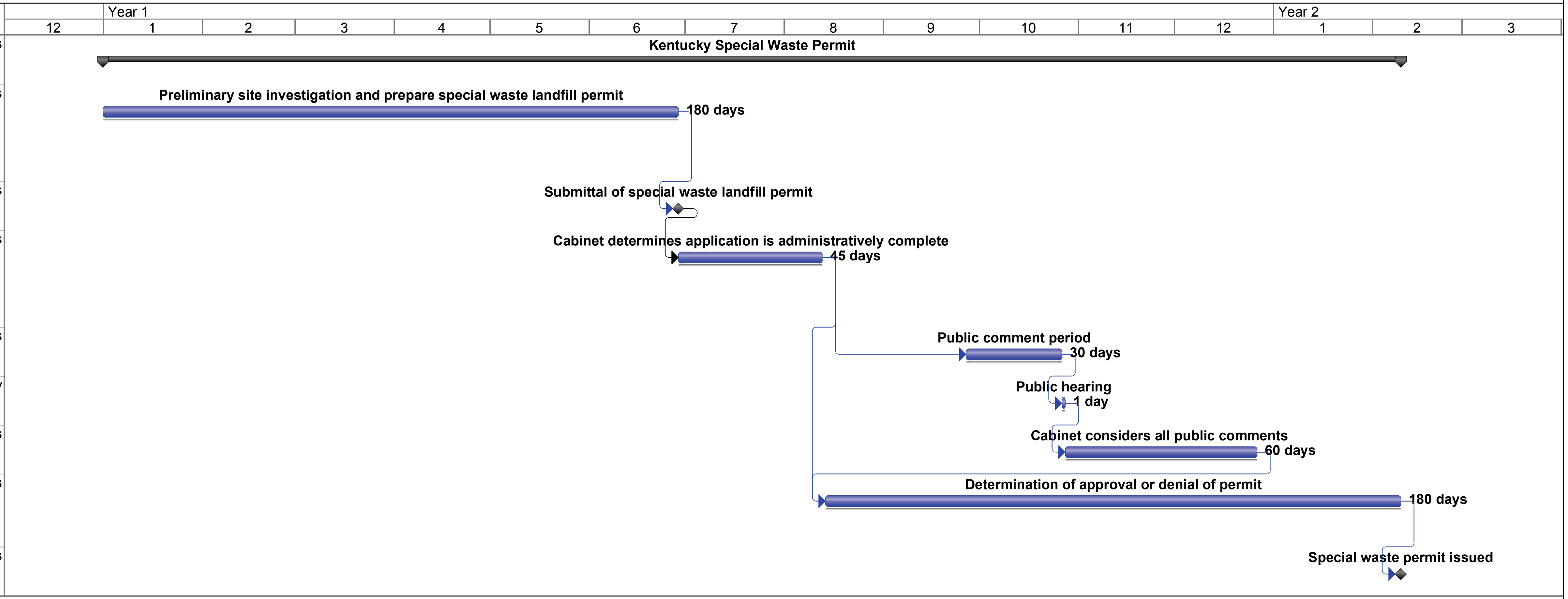
Figure 2.2 - KENTUCKY SPECIAL WASTE PROCESS

ID	Task Name	Duration
1	**1 Kentucky Special Waste Permit**	**406 days**
2	1.1 Preliminary site investigation and prepare special waste landfill permit	180 days
3	1.2 Submittal of special waste landfill permit	0 days
4	1.3 Cabinet determines application is administratively complete	45 days
5	1.4 Public comment period	30 days
6	1.5 Public hearing	1 day
7	1.6 Cabinet considers all public comments	60 days
8	1.7 Determination of approval or denial of permit	180 days
9	1.8 Special waste permit issued	0 days

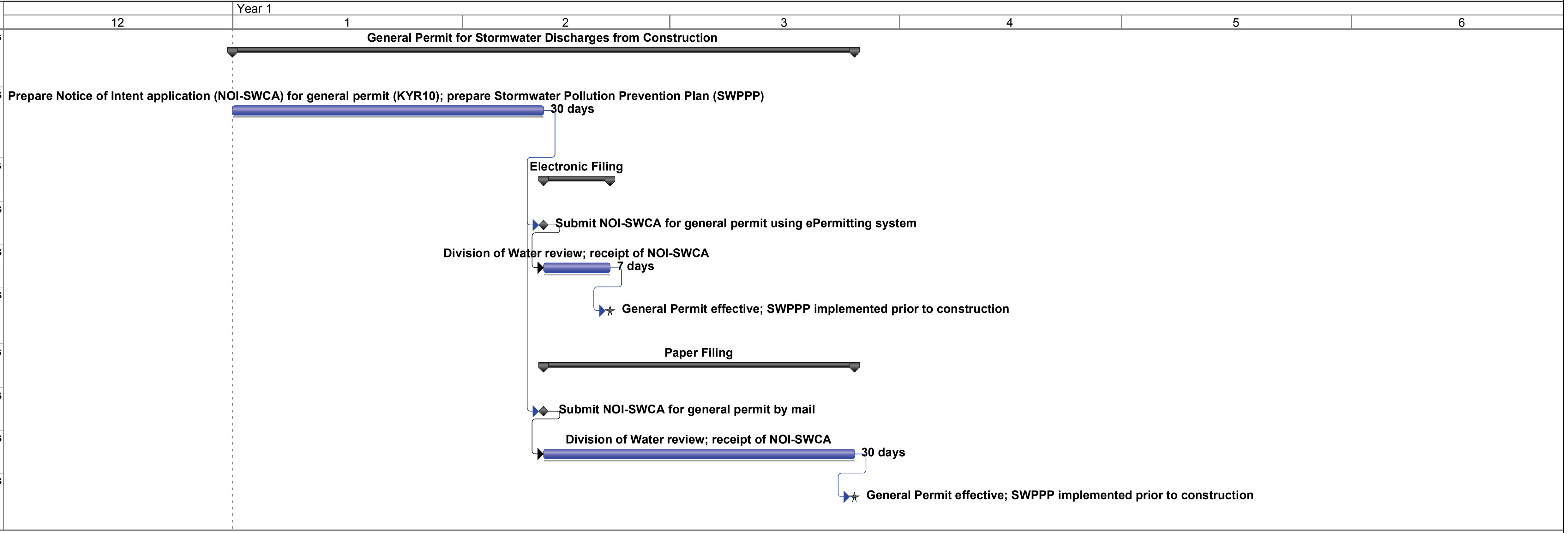


Project: Special Waste Permit Process
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	⋯	Milestone	◆	Project Summary	▬	External Milestone	◆		

Figure 2.3A - CONSTRUCTION GENERAL STORMWATER PERMIT PROCESS

ID	Task Name	Duration
1	**1 General Permit for Stormwater Discharges from Construction**	**60 days**
2	1.1 Prepare Notice of Intent application (NOI-SWCA) for general permit (KYR10); prepare Stormwater Pollution Prevention Plan (SWPPP)	30 days
3	**1.2 Electronic Filing**	**7 days**
4	1.2.1 Submit NOI-SWCA for general permit using ePermitting system	0 days
5	1.2.2 Division of Water review; receipt of NOI-SWCA	7 days
6	1.2.3 General Permit effective; SWPPP implemented prior to construction	0 days
7	**1.3 Paper Filing**	**30 days**
8	1.3.1 Submit NOI-SWCA for general permit by mail	0 days
9	1.3.2 Division of Water review; receipt of NOI-SWCA	30 days
10	1.3.3 General Permit effective; SWPPP implemented prior to construction	0 days

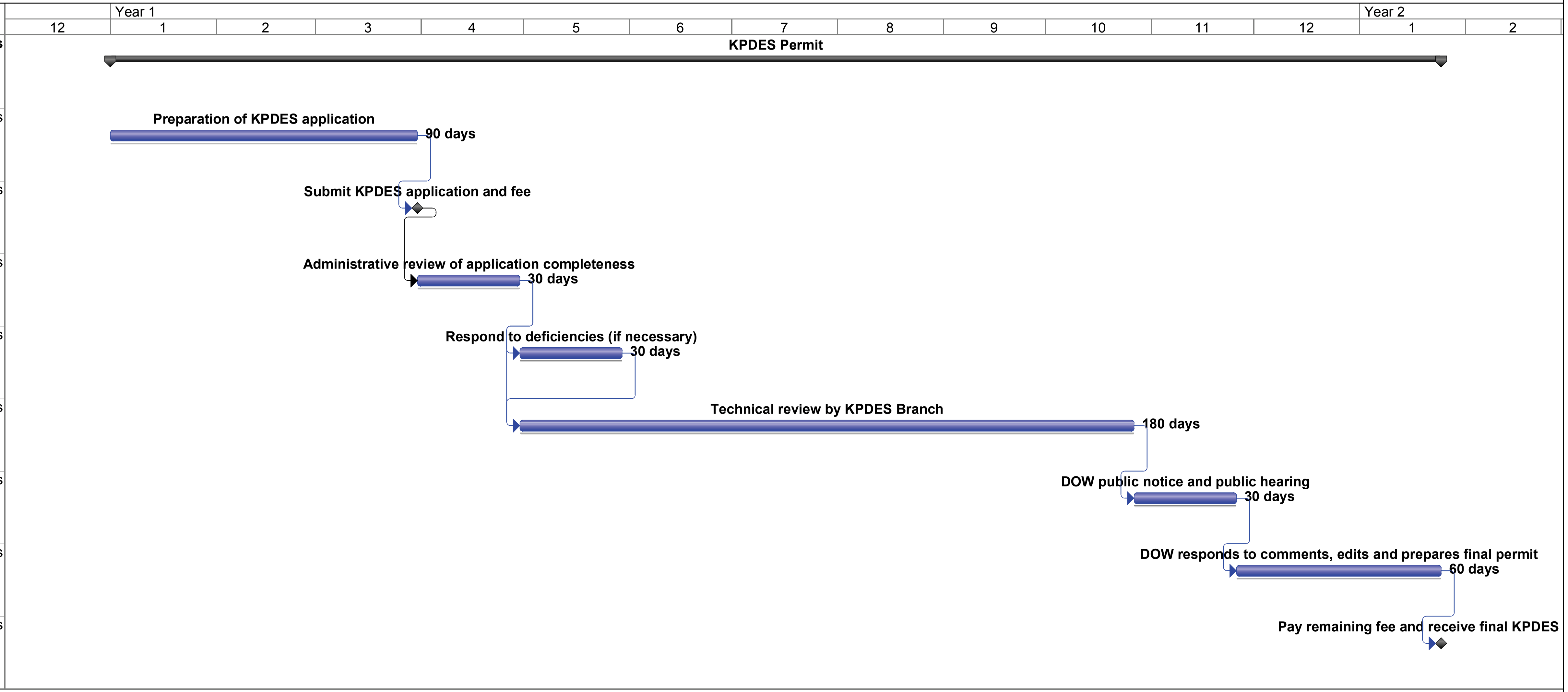


Project: General Permit for Stormwater from Construction
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline ⇩
Split	⋯	Milestone	◆	Project Summary	▬	External Milestone ◆		

Figure 2.3B - KPDES PERMIT PROCESS

ID	Task Name	Duration
1	**1 KPDES Permit**	**390 days**
2	1.1 Preparation of KPDES application	90 days
3	1.2 Submit KPDES application and fee	0 days
4	1.3 Administrative review of application completeness	30 days
5	1.4 Respond to deficiencies (if necessary)	30 days
6	1.5 Technical review by KPDES Branch	180 days
7	1.6 DOW public notice and public hearing	30 days
8	1.7 DOW responds to comments, edits and prepares final permit	60 days
9	1.8 Pay remaining fee and receive final KPDES permit	0 days

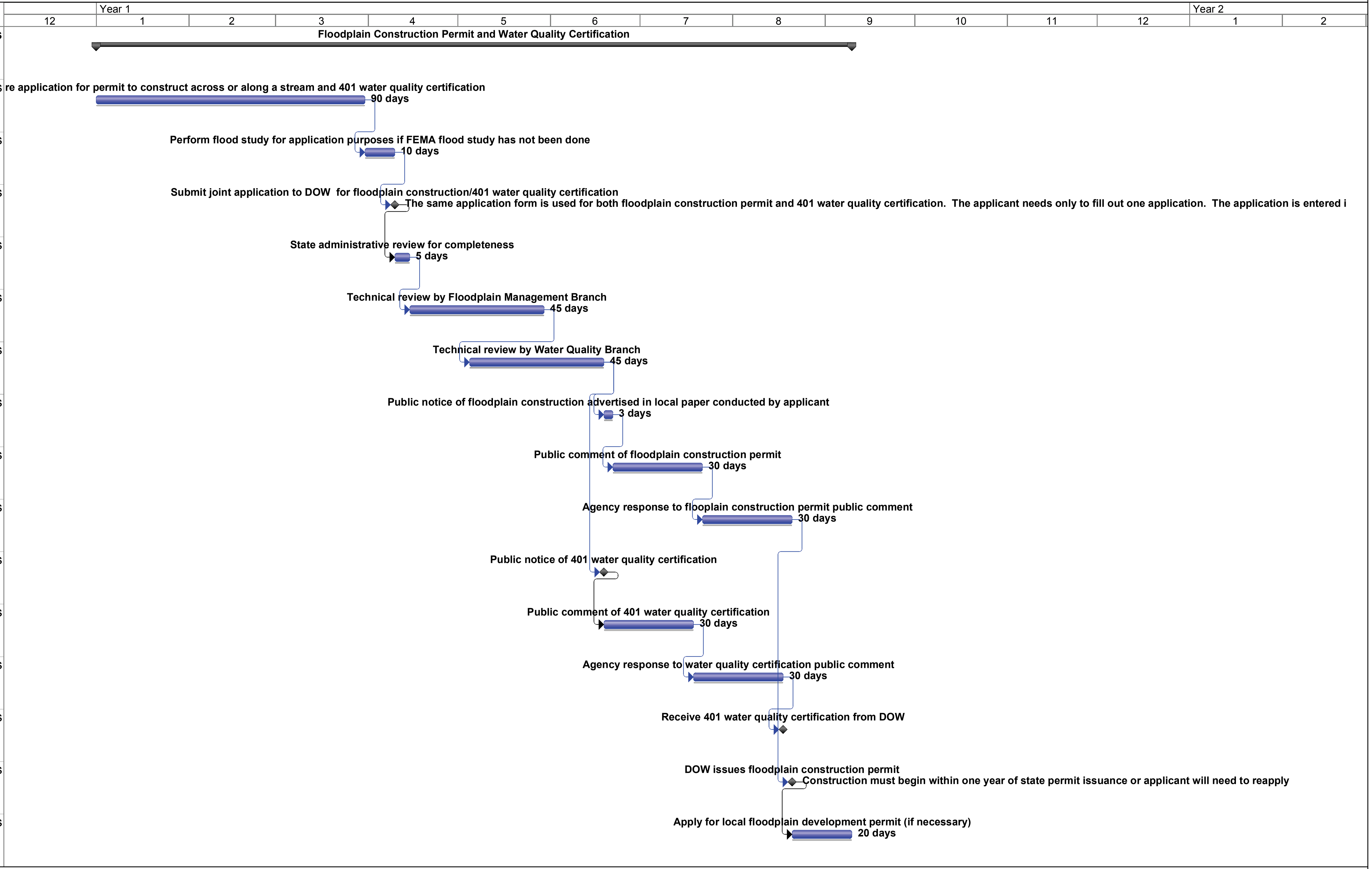


Project: KPDES Permit Process
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	┄	Milestone	◆	Project Summary	▬	External Milestone	◆		

Figure 2.4 - FLOODPLAIN CONSTRUCTION AND WATER QUALITY CERTIFICATION PROCESS

ID	Task Name	Duration
1	**1 Floodplain Construction Permit and Water Quality Certification**	**253 days**
2	1.1 Prepare application for permit to construct across or along a stream and 401 water quality certification	90 days
3	1.2 Perform flood study for application purposes if FEMA flood study has not been done	10 days
4	1.3 Submit joint application to DOW for floodplain construction/401 water quality certification	0 days
5	1.4 State administrative review for completeness	5 days
6	1.5 Technical review by Floodplain Management Branch	45 days
7	1.6 Technical review by Water Quality Branch	45 days
8	1.7 Public notice of floodplain construction advertised in local paper conducted by applicant	3 days
9	1.8 Public comment of floodplain construction permit	30 days
10	1.9 Agency response to flooplain construction permit public comment	30 days
11	1.10 Public notice of 401 water quality certification	0 days
12	1.11 Public comment of 401 water quality certification	30 days
13	1.12 Agency response to water quality certification public comment	30 days
14	1.13 Receive 401 water quality certification from DOW	0 days
15	1.14 DOW issues floodplain construction permit	0 days
16	1.15 Apply for local floodplain development permit (if necessary)	20 days

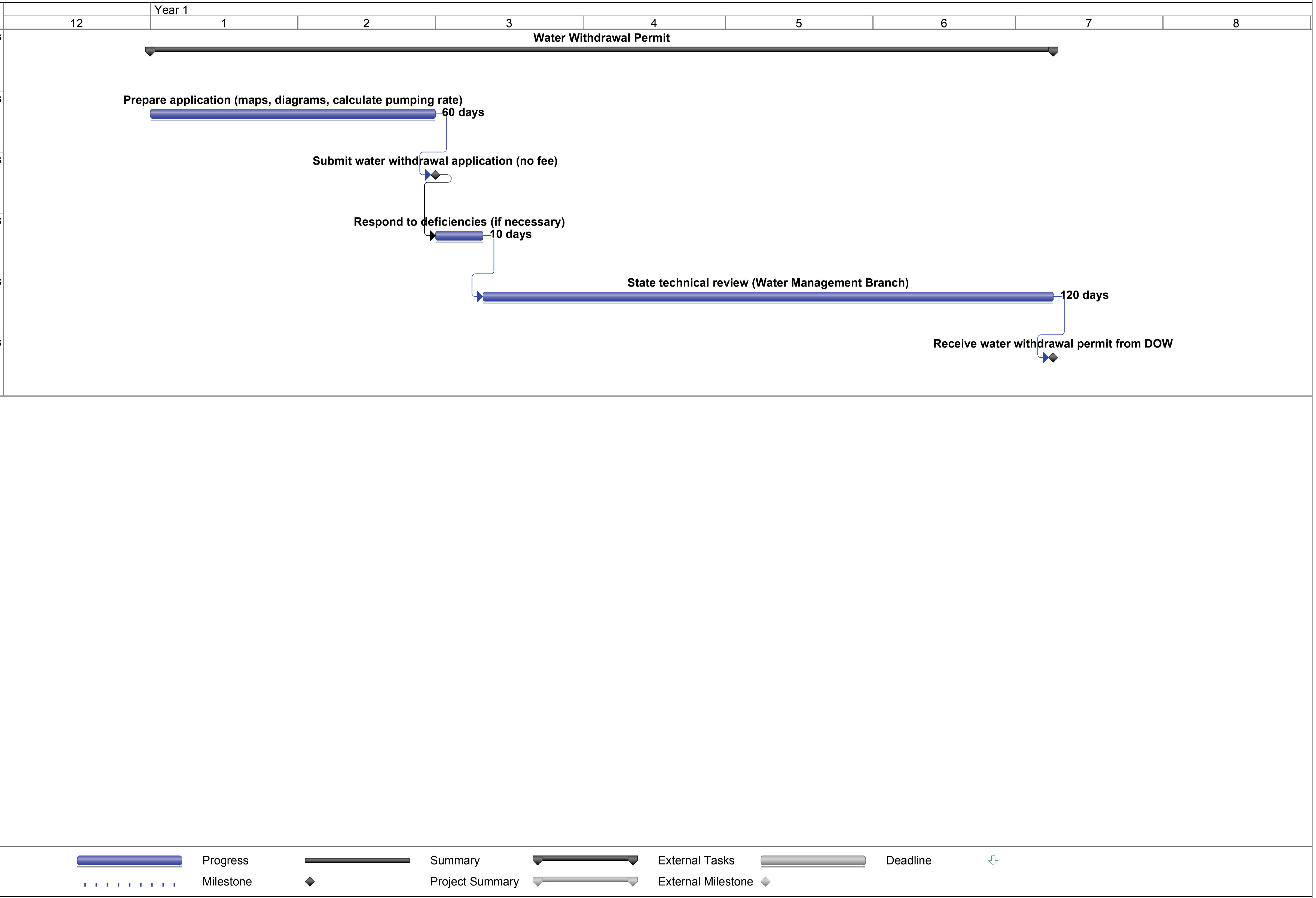


Project: Floodplain and Water Quality Certification
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	⋯	Milestone	◆	Project Summary	▬	External Milestone	◆		

Figure 2.5 - WATER WITHDRAWAL PERMIT PROCESS

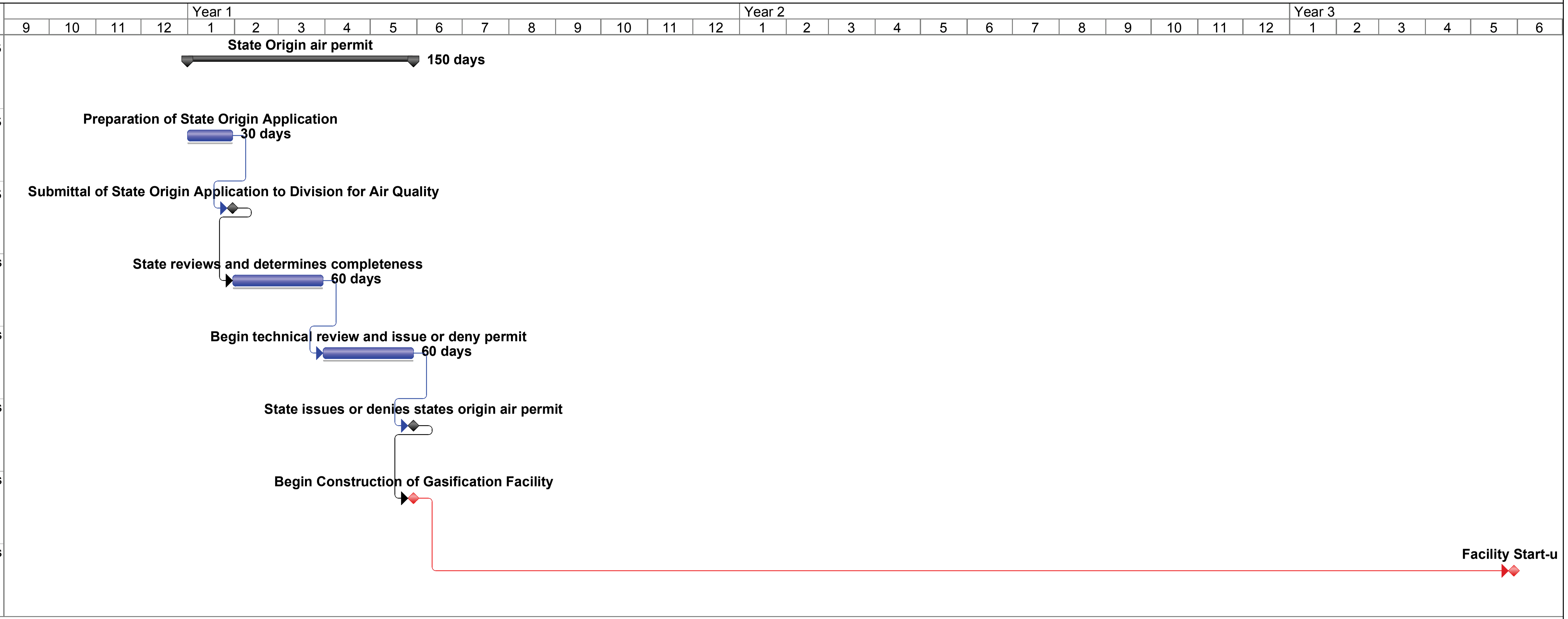
ID	Task Name	Duration
1	**1 Water Withdrawal Permit**	**190 days**
2	1.1 Prepare application (maps, diagrams, calculate pumping rate)	60 days
3	1.2 Submit water withdrawal application (no fee)	0 days
4	1.3 Respond to deficiencies (if necessary)	10 days
5	1.4 State technical review (Water Management Branch)	120 days
6	1.5 Receive water withdrawal permit from DOW	0 days



Project: Water Withdrawl Permit Process
Date: 10/7/2009

Figure 2.8.1 - STATE ORIGIN AIR PERMIT PROCESS

ID	Task Name	Duration
1	**1 State Origin air permit**	**150 days**
2	1.1 Preparation of State Origin Application	30 days
3	1.2 Submittal of State Origin Application to Division for Air Quality	0 days
4	1.3 State reviews and determines completeness	60 days
5	1.4 Begin technical review and issue or deny permit	60 days
6	1.5 State issues or denies states origin air permit	0 days
7	2 Begin Construction of Gasification Facility	0 days
8	3 Facility Start-up	0 days



Project: State Origin Air Permit
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	┆	Milestone	◆	Project Summary	▬	External Milestone	◆		

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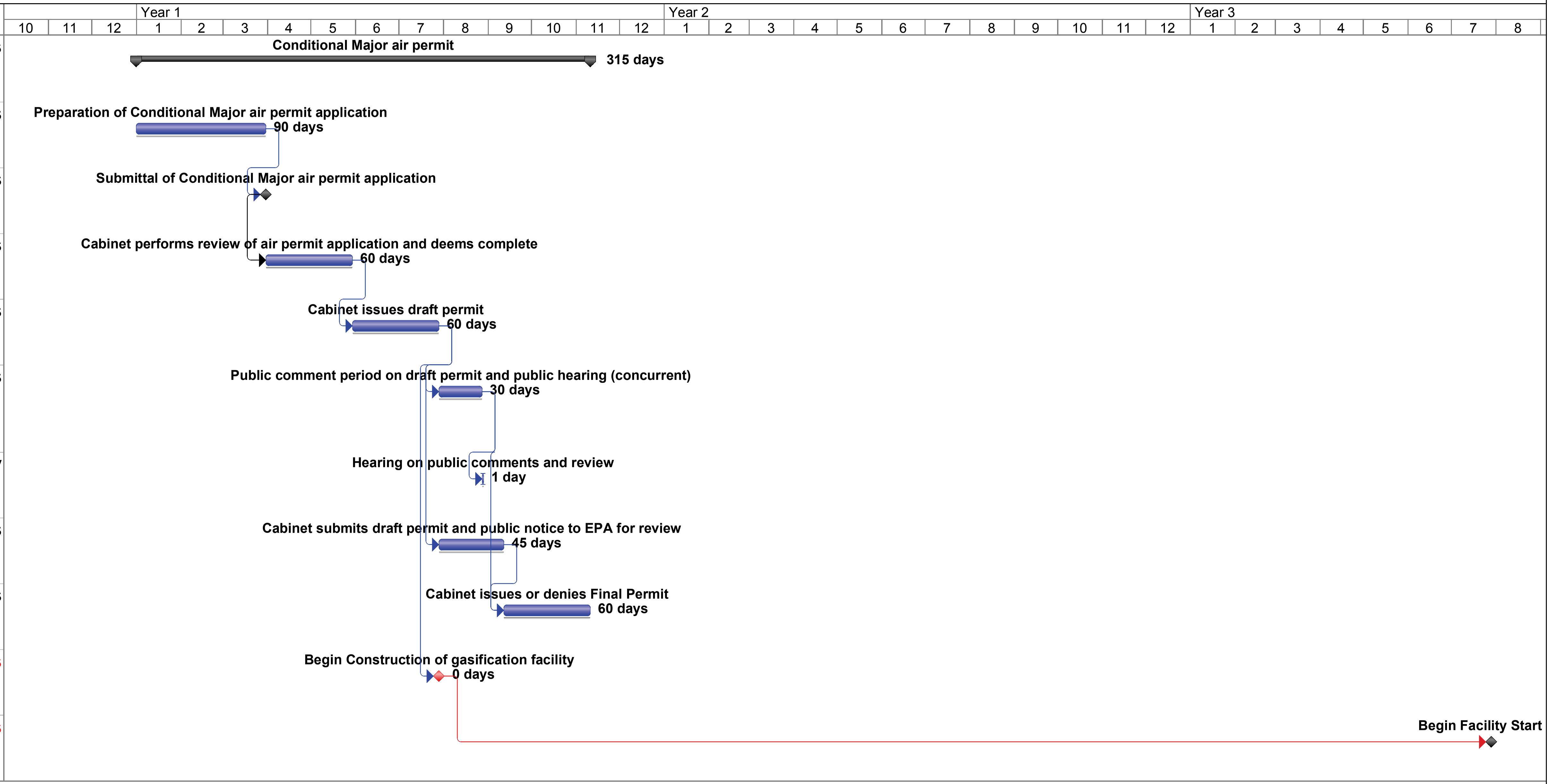
Figure 2.8.2 - CONDITIONAL MAJOR AIR PERMIT PROCESS

ID	Task Name	Duration
1	**1 Conditional Major air permit**	**315 days**
2	1.1 Preparation of Conditional Major air permit application	90 days
3	1.2 Submittal of Conditional Major air permit application	0 days
4	1.3 Cabinet performs review of air permit application and deems complete	60 days
5	1.4 Cabinet issues draft permit	60 days
6	1.5 Public comment period on draft permit and public hearing (concurrent)	30 days
7	1.6 Hearing on public comments and review	1 day
8	1.7 Cabinet submits draft permit and public notice to EPA for review	45 days
9	1.8 Cabinet issues or denies Final Permit	60 days
10	**2 Begin Construction of gasification facility**	**0 days**
11	**3 Begin Facility Start-Up**	**0 days**



Project: Conditional Major Air Permit Process
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline ⇩
Split	⋯	Milestone	◆	Project Summary	▬	External Milestone	◆	

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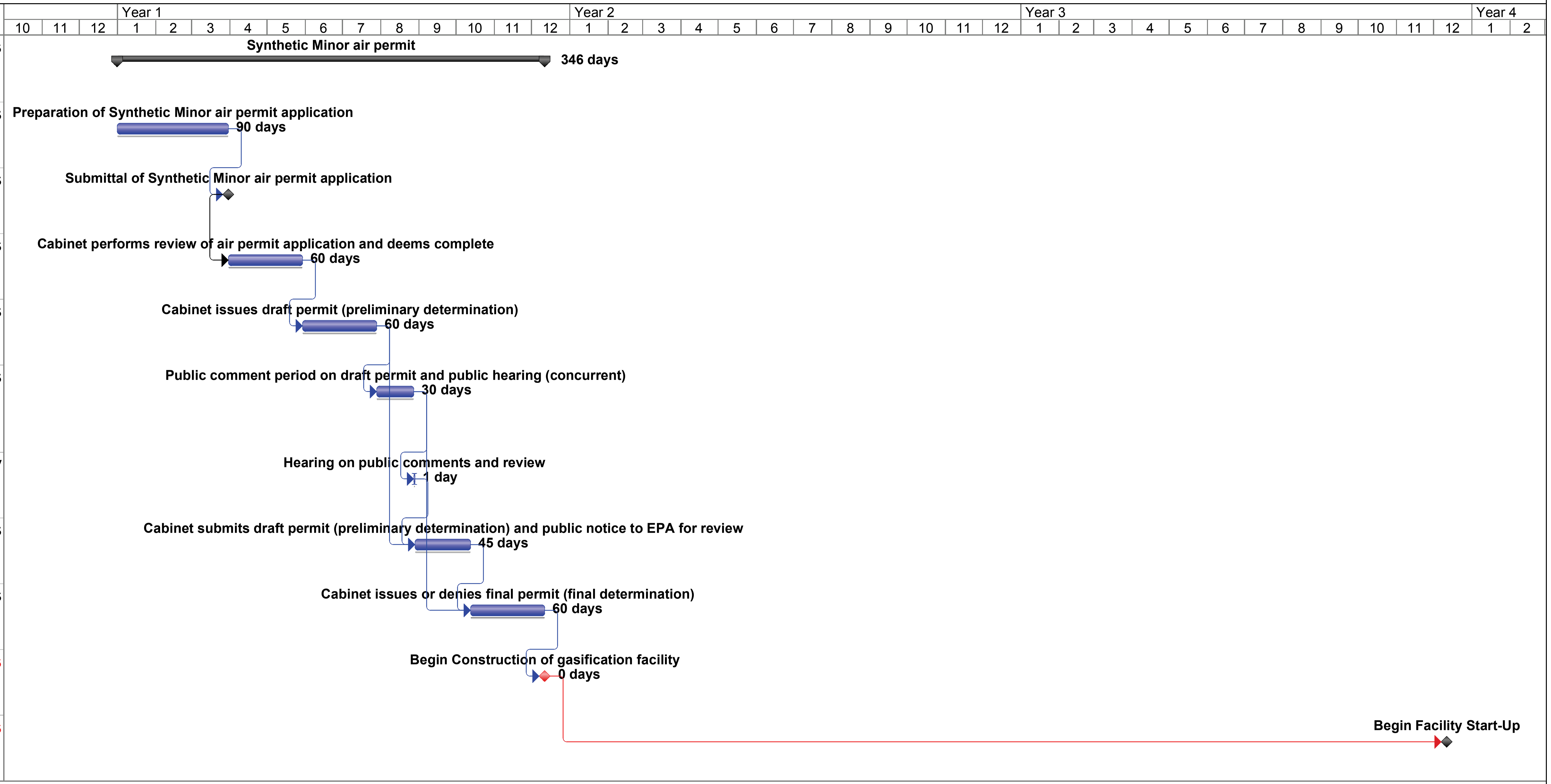
Figure 2.8.3 - SYNTHETIC MINOR AIR PERMIT PROCESS

ID	Task Name	Duration
1	**1 Synthetic Minor air permit**	**346 days**
2	1.1 Preparation of Synthetic Minor air permit application	90 days
3	1.2 Submittal of Synthetic Minor air permit application	0 days
4	1.3 Cabinet performs review of air permit application and deems complete	60 days
5	1.4 Cabinet issues draft permit (preliminary determination)	60 days
6	1.5 Public comment period on draft permit and public hearing (concurrent)	30 days
7	1.6 Hearing on public comments and review	1 day
8	1.7 Cabinet submits draft permit (preliminary determination) and public	45 days
9	1.8 Cabinet issues or denies final permit (final determination)	60 days
10	**2 Begin Construction of gasification facility**	**0 days**
11	**3 Begin Facility Start-Up**	**0 days**

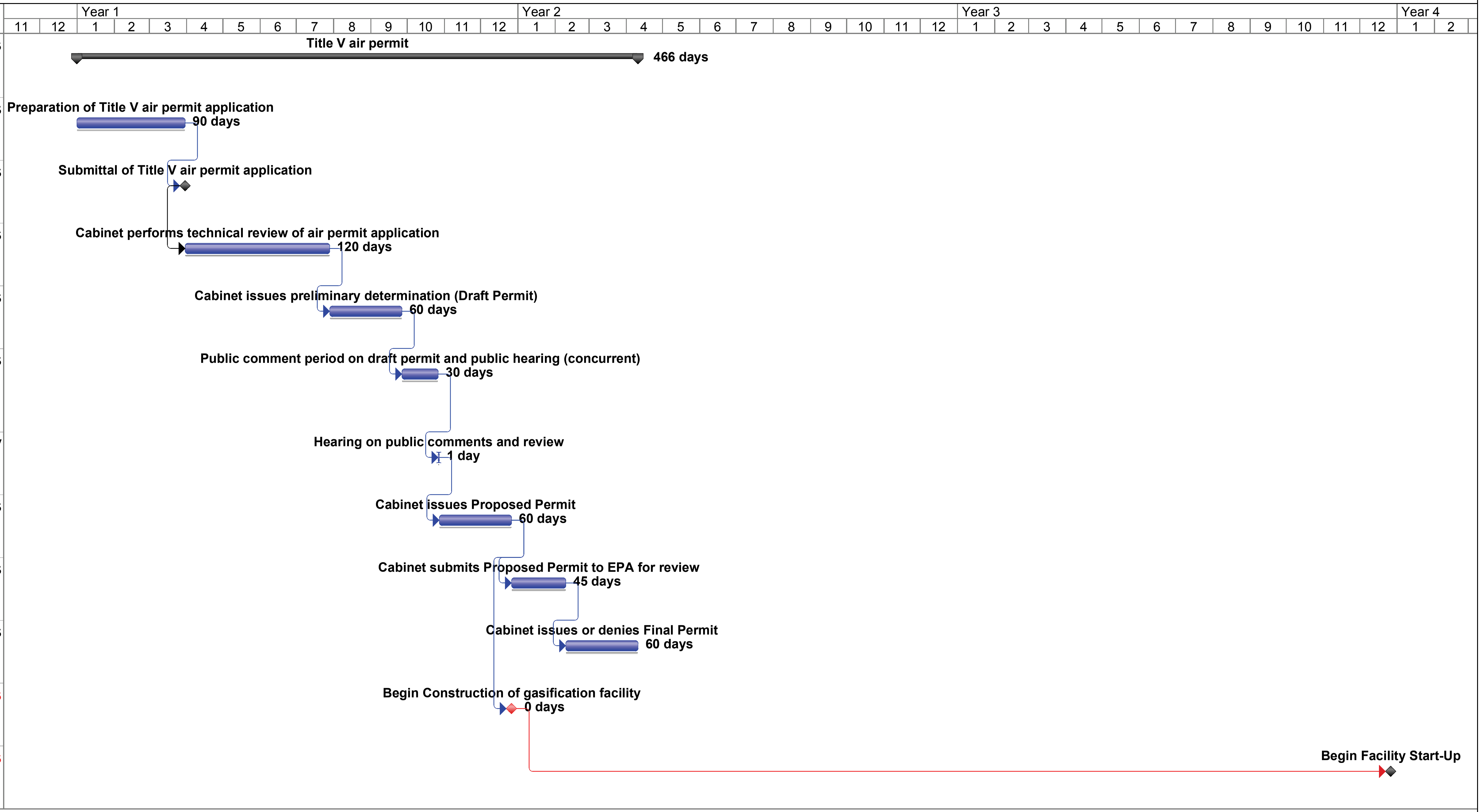


Project: Synthetic Minor Air Permit Process
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	┄	Milestone	◆	Project Summary	▬	External Milestone	◆		

Figure 2.8.4 - TITLE V AIR PERMIT PROCESS

ID	Task Name	Duration
1	**1 Title V air permit**	**466 days**
2	1.1 Preparation of Title V air permit application	90 days
3	1.2 Submittal of Title V air permit application	0 days
4	1.3 Cabinet performs technical review of air permit application	120 days
5	1.4 Cabinet issues preliminary determination (Draft Permit)	60 days
6	1.5 Public comment period on draft permit and public hearing (concurrent)	30 days
7	1.6 Hearing on public comments and review	1 day
8	1.7 Cabinet issues Proposed Permit	60 days
9	1.8 Cabinet submits Proposed Permit to EPA for review	45 days
10	1.9 Cabinet issues or denies Final Permit	60 days
11	**2 Begin Construction of gasification facility**	**0 days**
12	**3 Begin Facility Start-Up**	**0 days**

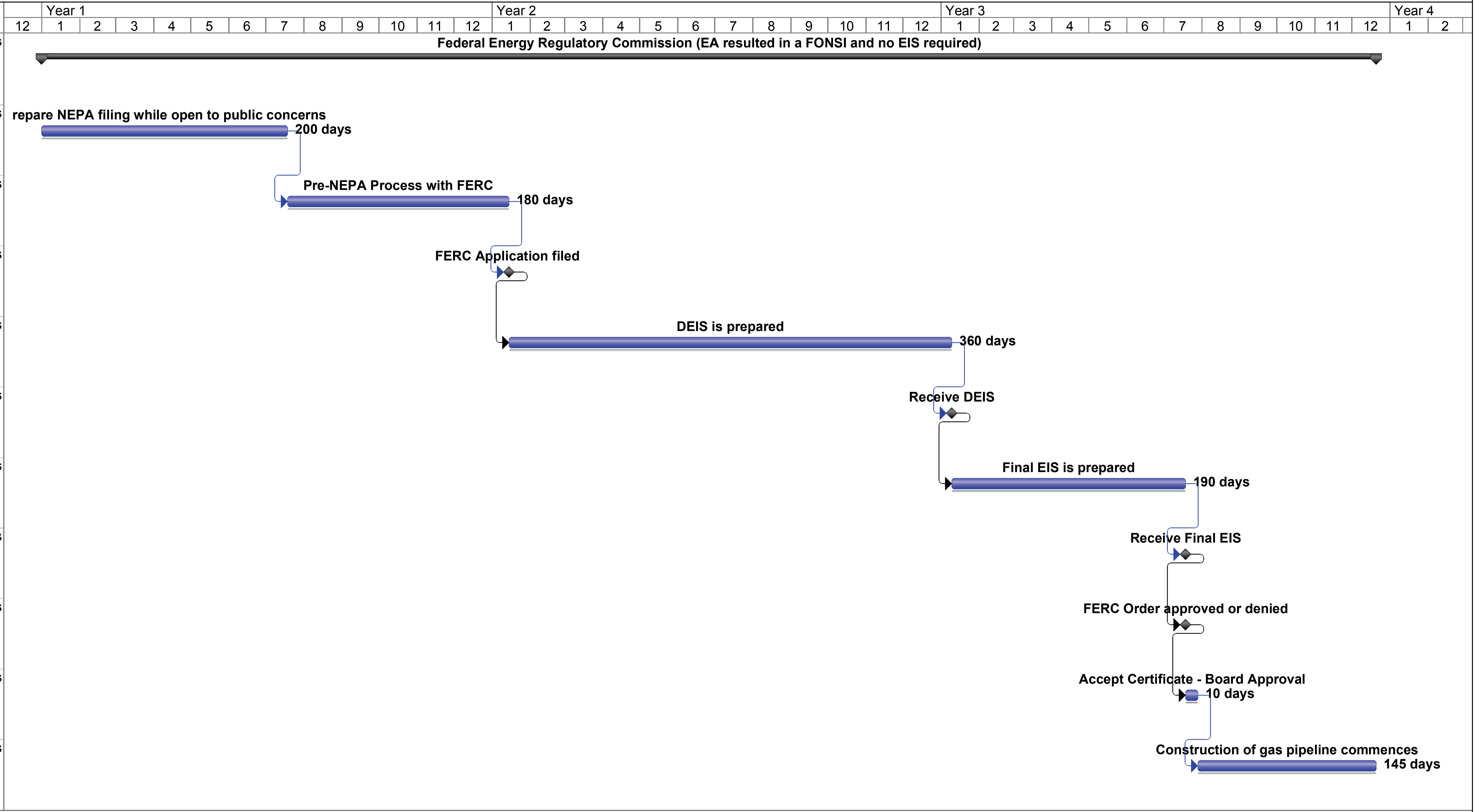


Project: Title V Air Permit Process
Date: 10/7/2009

Task	Progress		Summary		External Tasks		Deadline	⇩
Split	Milestone	◆	Project Summary		External Milestone	◇		

Figure 3.1 - FEDERAL ENERGY REGULATORY COMMISSION APPROVAL PROCESS

ID	Task Name	Duration
1	**1 Federal Energy Regulatory Commission (EA resulted in a FONSI and no EIS required)**	**1085 days**
2	1.1 Prepare NEPA filing while open to public concerns	200 days
3	1.2 Pre-NEPA Process with FERC	180 days
4	1.3 FERC Application filed	0 days
5	1.4 DEIS is prepared	360 days
6	1.5 Receive DEIS	0 days
7	1.6 Final EIS is prepared	190 days
8	1.7 Receive Final EIS	0 days
9	1.8 FERC Order approved or denied	0 days
10	1.9 Accept Certificate - Board Approval	10 days
11	1.10 Construction of gas pipeline commences	145 days

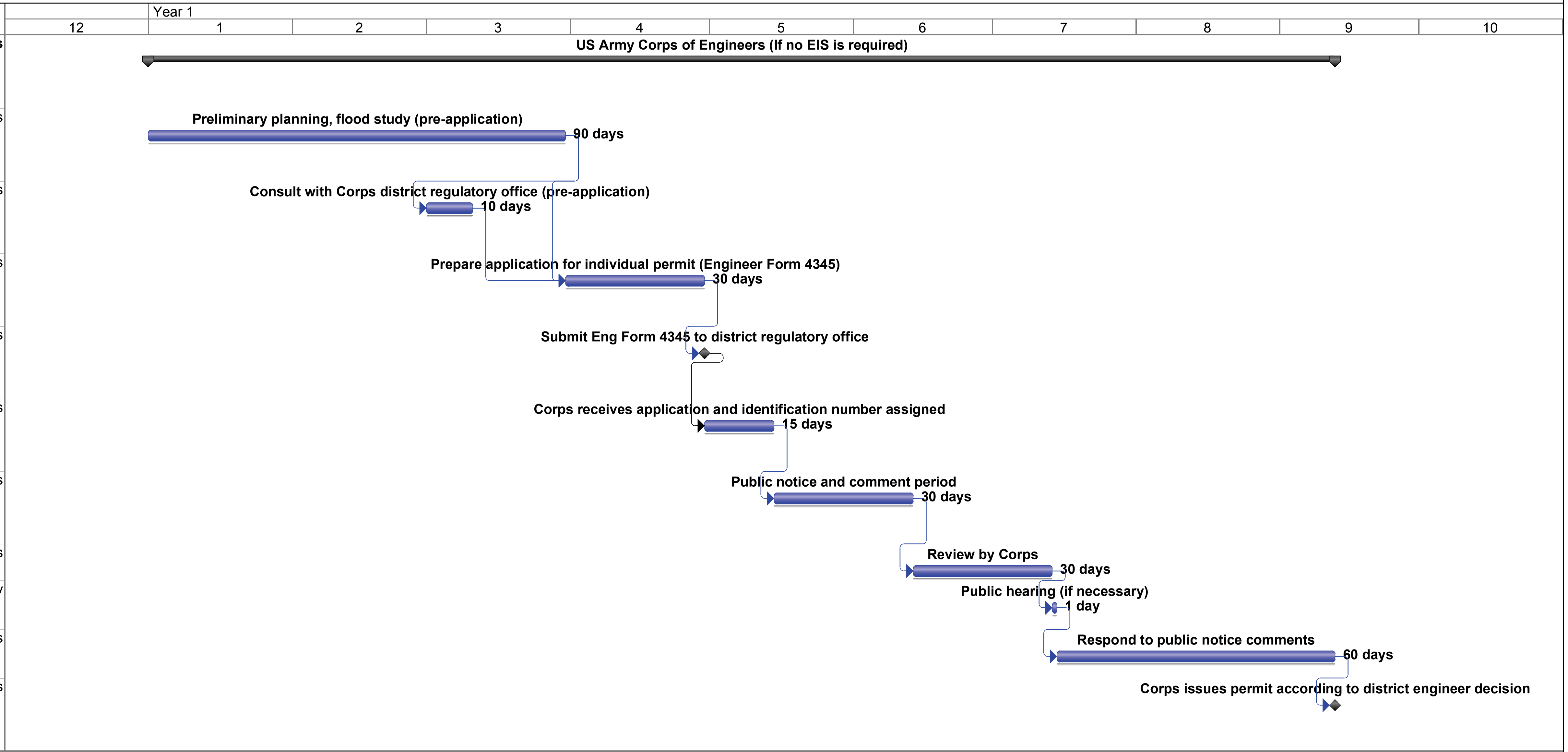


Project: FERC Process
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	⋯	Milestone	◆	Project Summary	▬	External Milestone	◆		

Figure 3.2.1 - US ARMY CORPS OF ENGINEERS PERMIT PROCESS

ID	Task Name	Duration
1	**1 US Army Corps of Engineers (If no EIS is required)**	**256 days**
2	1.1 Preliminary planning, flood study (pre-application)	90 days
3	1.2 Consult with Corps district regulatory office (pre-application)	10 days
4	1.3 Prepare application for individual permit (Engineer Form 4345)	30 days
5	1.4 Submit Eng Form 4345 to district regulatory office	0 days
6	1.5 Corps receives application and identification number	15 days
7	1.6 Public notice and comment period	30 days
8	1.7 Review by Corps	30 days
9	1.8 Public hearing (if necessary)	1 day
10	1.9 Respond to public notice comments	60 days
11	1.10 Corps issues permit according to district engineer decision	0 days

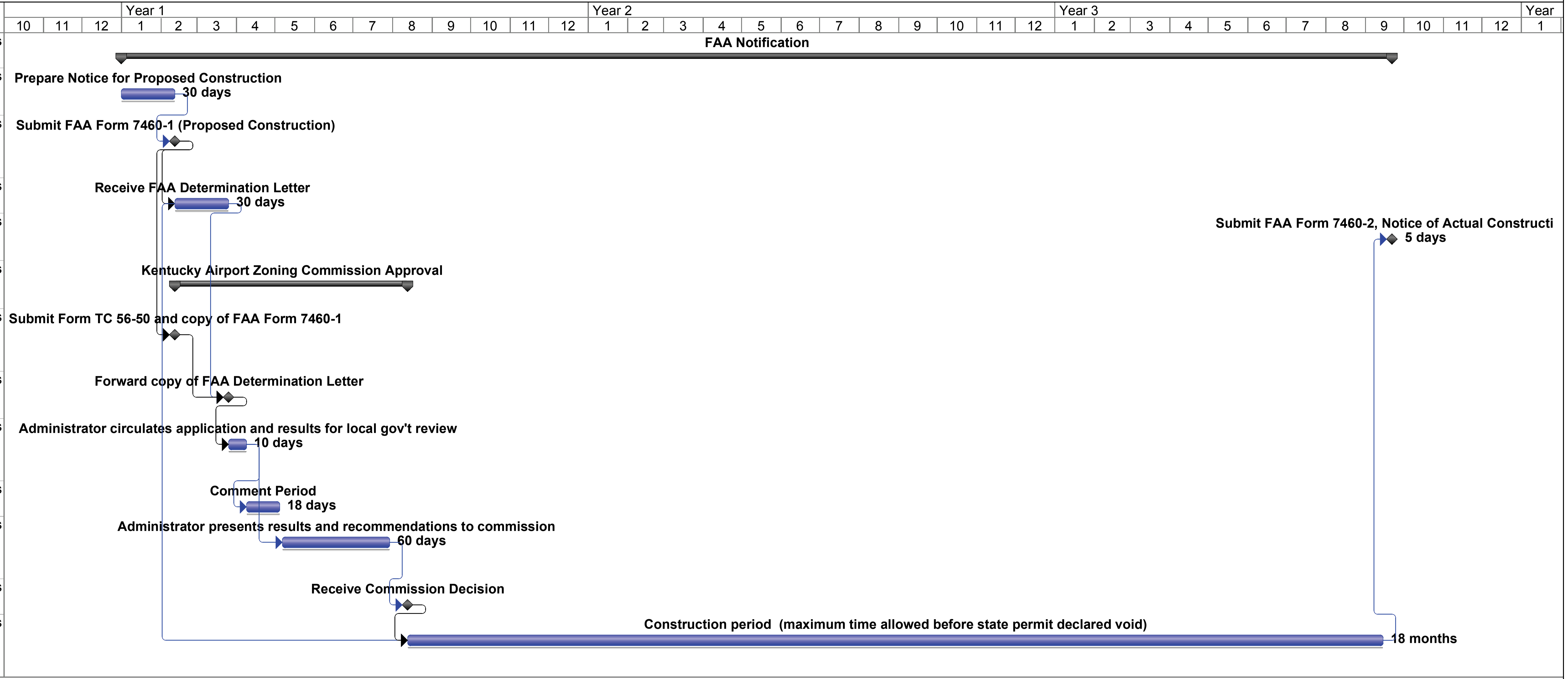


Project: US Army Corps of Engineers Individual Permit Process
Date: 10/7/2009

Task
Split
Progress
Milestone ◆
Summary
Project Summary
External Tasks
External Milestone ◆
Deadline ⇩

Figure 3.1 - Federal Aviation Administration and KY Airport Zoning Notification Process

ID	Task Name	Duration
1	**1 FAA Notification**	**710 days**
2	1.1 Prepare Notice for Proposed Construction	30 days
3	1.2 Submit FAA Form 7460-1 (Proposed Construction)	0 days
4	1.3 Receive FAA Determination Letter	30 days
5	1.4 Submit FAA Form 7460-2, Notice of Actual Construction	5 days
6	**2 Kentucky Airport Zoning Commission Approval**	**130 days**
7	2.1 Submit Form TC 56-50 and copy of FAA Form 7460-1	0 days
8	2.2 Forward copy of FAA Determination Letter	0 days
9	2.3 Administrator circulates application and results for local gov't review	10 days
10	2.4 Comment Period	18 days
11	2.5 Administrator presents results and recommendations to commission	60 days
12	2.6 Receive Commission Decision	0 days
13	3 Construction period (maximum time allowed before state permit declared void)	545 days



Project: Federal Aviation Administration and KY Airport Zoning Process
Date: 10/13/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	....	Milestone	◆	Project Summary	▬	External Milestone	◆		

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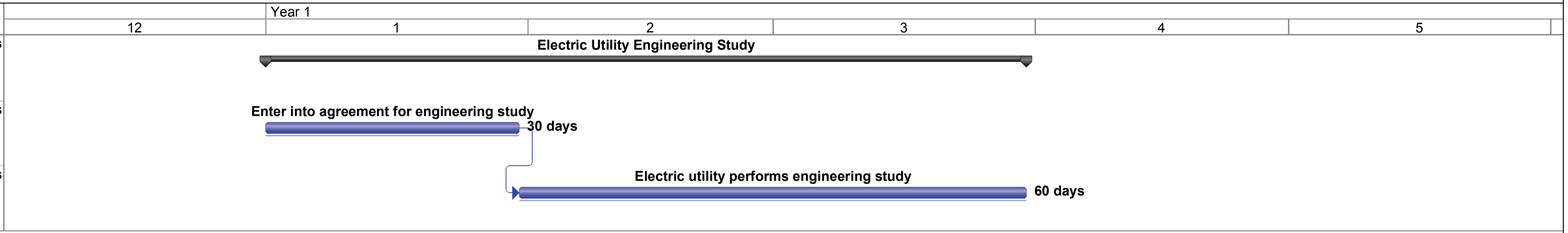
Figure 5.1 - ELECTRIC UTILITY APPROVAL PROCESS

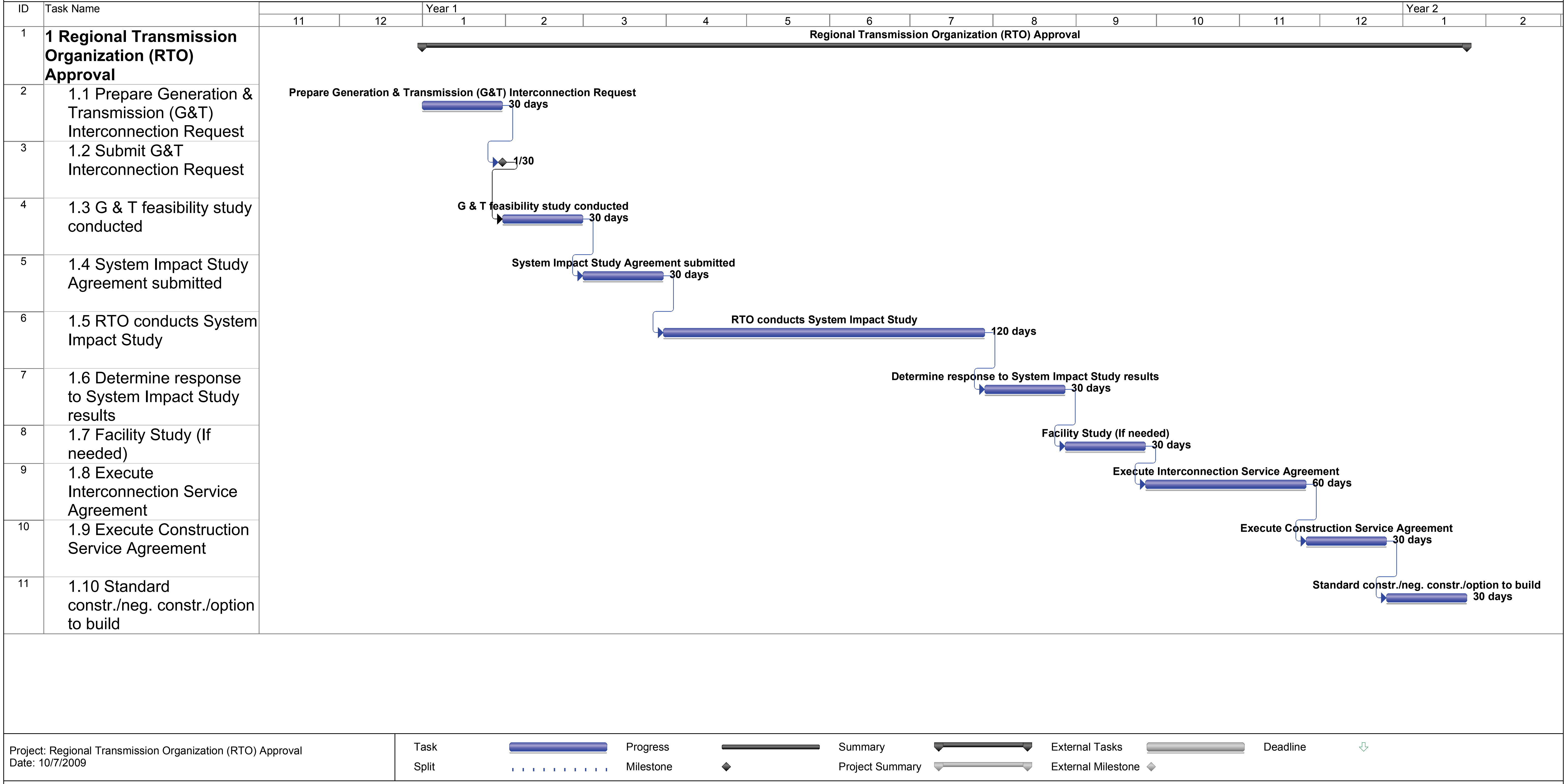
ID	Task Name	Duration
1	**1 Electric Utility Engineering Study**	**90 days**
2	1.1 Enter into agreement for engineering study	30 days
3	1.2 Electric utility performs engineering study	60 days



Project: Electric Utility Approval Process
Date: 10/7/2009

Task ▬ Progress ▬ Summary ▬ External Tasks ▬ Deadline ⇩
Split ⋯ Milestone ◆ Project Summary ▬ External Milestone ◆

Figure 5.2 - REGIONAL TRANSMISSION ORGANIZATION APPROVAL PROCESS

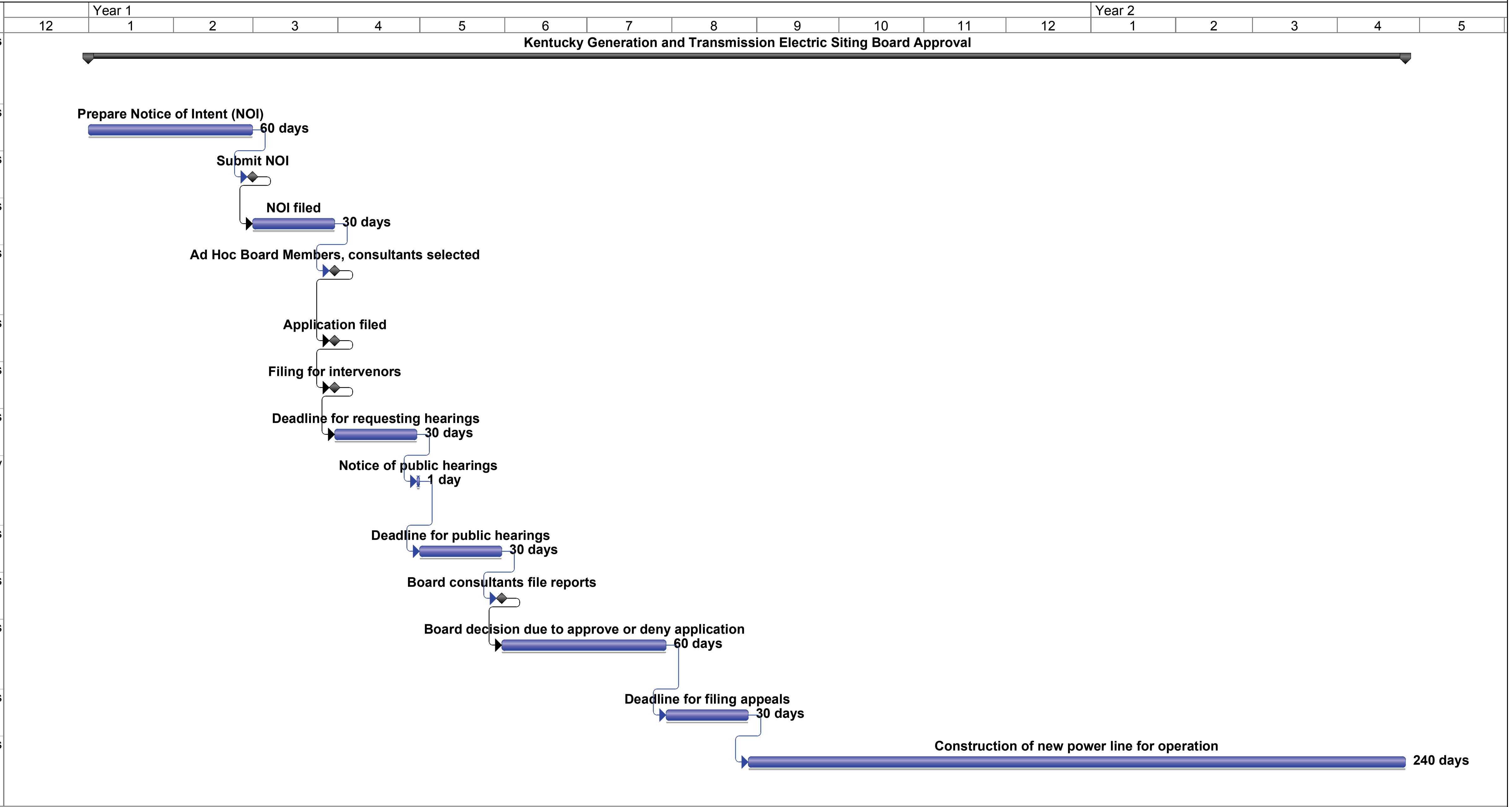


ID	Task Name
1	**1 Regional Transmission Organization (RTO) Approval**
2	1.1 Prepare Generation & Transmission (G&T) Interconnection Request
3	1.2 Submit G&T Interconnection Request
4	1.3 G & T feasibility study conducted
5	1.4 System Impact Study Agreement submitted
6	1.5 RTO conducts System Impact Study
7	1.6 Determine response to System Impact Study results
8	1.7 Facility Study (If needed)
9	1.8 Execute Interconnection Service Agreement
10	1.9 Execute Construction Service Agreement
11	1.10 Standard constr./neg. constr./option to build

Project: Regional Transmission Organization (RTO) Approval
Date: 10/7/2009

Figure 5.3 - KENTUCKY GENERATION AND TRANSMISSION ELECTRIC SITING BOARD APPROVAL PROCESS

ID	Task Name	Duration
1	**1 Kentucky Generation and Transmission Electric Siting Board Approval**	**481 days**
2	1.1 Prepare Notice of Intent (NOI)	60 days
3	1.2 Submit NOI	0 days
4	1.3 NOI filed	30 days
5	1.4 Ad Hoc Board Members, consultants selected	0 days
6	1.5 Application filed	0 days
7	1.6 Filing for intervenors	0 days
8	1.7 Deadline for requesting hearings	30 days
9	1.8 Notice of public hearings	1 day
10	1.9 Deadline for public hearings	30 days
11	1.10 Board consultants file reports	0 days
12	1.11 Board decision due to approve or deny application	60 days
13	1.12 Deadline for filing appeals	30 days
14	1.13 Construction of new power line for operation	240 days



Project: Siting Board Approval
Date: 10/7/2009

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline ⇩
Split	⋯	Milestone	◆	Project Summary	▬	External Milestone ◆		

Ideas for Better Stakeholder Involvement In the Interstate Natural Gas Pipeline Planning Pre-Filing Process

Industry, Agencies, Citizens, and FERC Staff

Prepared by:
FERC Staff
OEP Gas Outreach Team
December 2001

Table of Contents

Introduction

This document was developed by the Office of Energy Projects (OEP) Gas Outreach Team using the feedback and ideas collected from stakeholders at our pre-filing outreach seminars. It will be updated from time to time as needed, to incorporate new knowledge, techniques, or options that can help achieve consensus and a better application to the Federal Energy Regulatory Commission.

If you are viewing this document on the web site, click on the words that appear in blue to link to the glossary or to an appropriate web site. A full glossary also follows the document for further reference.

The concepts presented in this document are for discussion only, and do not necessarily represent the views of the Commission or its individual members.

Action Options Overview For Interstate Natural Gas Pipeline Siting

Early Involvement by All Stakeholders Can Develop Better Solutions

As a result of the comments and discussions at six Interstate Natural Gas Pipeline Facility Planning Seminars, the OEP Gas Outreach Team developed a set of Outreach Action Options for pipeline companies, agencies, citizens, and the FERC staff. The Action Options identify concepts, actions, and activities that will help each stakeholder group achieve more effective participation in the process of planning a natural gas pipeline.

For more information on how to be involved in a project from a landowner's perspective, see "An Interstate Natural Gas Pipeline on My Land? What Do I Need to Know?"

The U.S. Department of Transportation (DOT) is responsible for setting federal safety standards for natural gas pipelines and related facilities. The Office of Pipeline Safety at DOT is at www.dot.gov.

The objective is to provide the best possible guidance on different pre-filing techniques that can be used to address issues that are raised. Every pipeline project is different - its size, its location, the company's approach to working with stakeholders, the community's interest in participating, the agencies' experience with similar projects, etc. The goal of the Action Options is to offer some ideas that all stakeholders can customize for their needs.

Pipeline companies are encouraged to seek out greater involvement from the various groups early in the planning so those who are interested can participate in the decision-making process. Agencies and citizens are encouraged to get involved early and make their views known to the companies as soon as they learn about a potential project. The goal is to achieve consensus and settlements among the groups and the company about an acceptable project design. FERC staff has been asked to offer assistance early in the process to support all stakeholders. Earlier and more productive involvement will lead to better project designs and less contentious applications to FERC and other agencies.

Working together will pay off by helping to achieve agreements. Spending time up front will save time later. Consensus will be more easily achieved through implementing these ideas.

What All Stakeholders Need to Know

The Players

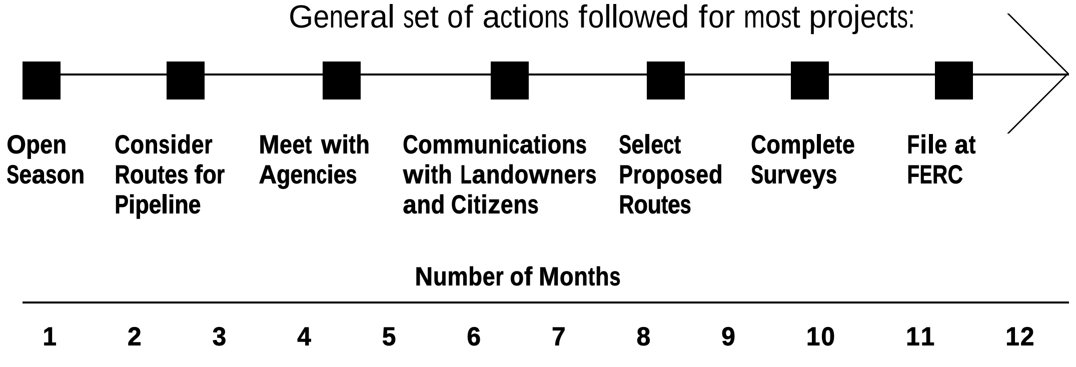
There are many different participants in the pipeline planning process.

- FERC - is charged by Congress with determining whether interstate natural gas transmission projects are in the public convenience and necessity.
- Pipeline Companies - These are the companies that build and operate interstate natural gas pipelines. They must justify the need, plan the route, and obtain numerous local, state and federal permits and clearances prior to construction.
- Federal, State and Local Agencies - The best way to find out who is involved from your local and state government is to call a local town official or a pipeline company representative and ask. Some typical agencies involved in the planning process include:
    - ⇒ **Local:** Town and County Councils, planning boards, zoning boards, and others
    - ⇒ **State:** Environmental agencies, historic preservation offices, fish and wildlife agencies, and others
    - ⇒ **Federal:** U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, U.S. Environmental Protection Agency, Bureau of Land Management and Forest Service

- Local citizens and landowners - have interests in whether the proposed natural gas line will impact their land or their community. Local citizens and landowners are encouraged to make their views known at any time in the process.

Pre-filing Timeline Example For a Major Project Requiring an EIS

General set of actions followed for most projects:



The Process

Generally, the formal process for evaluating a pipeline company's proposal to build an interstate natural gas pipeline begins when the company files an application with the FERC. The application includes maps showing the preferred route, the proposed facilities, the status of permit applications with local, state and federal agencies, affected landowners, and information on how the pipeline will affect the environment.

The FERC's review of the application and determination of need involves the balancing of the project's adverse impact against its benefits. The FERC's environmental analysis of the application under the National Environmental Policy Act of 1969 (NEPA) is part of that balancing. Public participation is a key element in FERC's environmental analysis.

The goal of the Action Options is to encourage participation in a process where all stakeholders have the opportunity to have input **before the development of the application**, so that issues are raised and addressed and solutions crafted and presented as part of the company's proposal.

Some Tips For All Stakeholders

- Ask other stakeholders how they want to be communicated with throughout this process.
- Agree up front on how stakeholders will be involved to set expectations at the start.
- Be patient—working together on a complex project requires understanding from all participants.
- Develop summary transcripts from meetings and share information with all stakeholders to keep the lines of communication open.
- Set up a process for what can be done if any stakeholder feels their needs are not being met. If everyone agrees on the process up front, there will be a way to address concerns.
- Remember that each stakeholder has control over their own actions and decisions. This is a voluntary process for all stakeholders.
- Formalize agreements in writing so everyone can be sure they understand and agree to what is decided.

NEPA IS...

- The National Environmental Policy Act of 1969 is legislation that requires federal agencies to consider the environmental impacts of their actions.
- It outlines a process for public input into the agencies' decision-making process.
- It requires that for major projects, a detailed environmental study be prepared, including the analysis of appropriate alternatives to the proposal.

Industry Action Options

Start Early, Be Pro-active, Involve Key Stakeholders

Natural gas pipeline companies and their consultants, contractors, and industry groups are the centerpiece of the pipeline siting process because they are the project planners and proponents. This group carries a large part of the responsibility to implement and coordinate the project activities that occur during the pre-filing time frame. There are a number of separate components to the actions that the company will need to take, including developing a company philosophy of commitment, ensuring agency participation, training company representatives and land agents, developing a public participation plan, collecting data, and having a plan for potential mitigation and compensation.

As part of its pre-filing groundwork the company should address internal and external planning and coordination issues. Pre-filing actions should be part of a coordinated plan, since they involve so many facets of a company and its consultants. Decisions on how to involve others should be made internally before they are implemented. It will also be important to train the project development team on the company philosophy and policy.

Dealing with agencies and citizens in a participatory decision-making process can help build consensus and resolve issues prior to filing. There will likely be some initial costs of time and money, but these up-front actions should result in quicker processing of an application and presentation of the record to the Commission for a decision.

Demonstrate Your Commitment to Public Involvement

- ♦ Companies should create a project team to interact with stakeholders. For large projects, the team should include environmental, engineering, and public relations professionals, in addition to other valuable experts. At least one company has formed a separate team specifically created for stakeholder outreach.
    - ⇒ Make sure the team is trained to perform the public involvement plan.
    - ⇒ Build the concept of public participation into training for all facets of the project development team.
- ♦ The company should decide early that it will be pro-active in getting agencies and land-

HAVE YOU:

- ✓ Asked the community how they'd like to receive information?
- ✓ Described the project in great detail to landowners?
- ✓ Explained to stakeholders how you will work with them in the pre-filing process?
- ✓ Told landowners about your company?
- ✓ Shared safety information?

owners involved in the process and the resolution of issues. Commit to being honest and open and following through in relationships with other stakeholders.

- As part of determining potential stakeholders for a project, identify and establish key contacts with:
    - ⇒ Governor(s) and federal, state, and local politicians
    - ⇒ Environmental agencies and groups
    - ⇒ Energy agencies/ PUCs
    - ⇒ FERC staff
    - ⇒ Non-governmental organizations
    - ⇒ Federal and state land managers
    - ⇒ Local distribution companies
    - ⇒ Landowner and community representatives

- Develop a positive attitude and company philosophy that includes a historical company mission perspective. Make sure employees at every level and in every division of the company understand the concept of public participation.

- When developing a public participation plan, consider how project announcements and first contacts will be made, and to whom meetings will be open. Be inclusive, get others involved early.

- Consider involving stakeholders in early efforts to develop the route.

- Be prepared to explain the need for the project to agencies and landowners. Explain the support the company has for the project at opportunities such as meetings and open houses, etc. Explain supply/demand and get help and/or information from public utility commissions (PUCs), the Energy Information Administration (EIA), independent system operators (ISOs) and local entities on regional issues important to landowners.

- In addition to sharing information about the benefits of a pipeline, commit to being open about the down sides too. The public will respect honesty and it may prevent future misunderstandings.

Involve stakeholders early and share information.

Maintain Strong, Open Channels of Communication with Agencies

- Develop a multifaceted, grass-roots strategy for announcing the project to federal, state, and local agencies (and to landowners), which maximizes their opportunity for input into identifying potential issues and their resolution.

- Describe the time table for the project and try to get agency contacts to commit to have their staffs work at the requested pace.

- Be clear about when and how landowners and agencies can best contribute to the planning process.

- Set up big picture meetings/briefings with agency policy staffs, but be sure to also hold detailed working sessions with technical staff.

  - ⇒ Conduct field visits to help get a better understanding of an issue.
  - ⇒ Consider the source of the information and whether it is really representative of the agency's assessment.

- Explore the potential for team permitting options among agencies. The value of early coordination and notification of problems is high.

- Tell federal agencies, local and regional officials, and state agencies about the project as early as possible, with as much detailed information as is available, so that they may tell citizens when they call. Ensure that the information is updated when events or schedules change. Consider developing materials that agencies can provide to interested stakeholders and develop a website with the latest information.

The value of early coordination and notification of problems is high.

- When and if limited resources prevent agencies from timely responses or actions, consider funding third-party contractors to work for them.

- Provide the FERC staff with accurate, advanced project information in as much detail as possible so that they can help coordinate outreach to other agencies.

Train Company Representatives and Land Agents

- Develop specific training for company representatives and land agents on the importance of company philosophy and their role in establishing good communication with landowners and continuing it. Landowners want to deal with someone who is personable, honest, and respectful.

  - ⇒ Land agents are either building or hurting the reputation of the company with all affected parties they meet.
  - ⇒ Landowner trust will be based in part on experience with the industry as a whole.
  - ⇒ Consider using local land agents or hiring local assistance to familiarize out-of-town land agents with local culture and geography.

- Train land agents in dealing with people and on the company's public participation plan.
  - ⇒ When people are upset, find out what people are upset about.
  - ⇒ Land agents should be willing to put commitments in writing or not make them.

Land agents are your representatives to the community.

Plan for Public Stakeholder Input Throughout the Process

- Make a commitment to involve affected landowners and other interested citizens in the project planning process. Inform them, listen to, and record landowner's ideas and knowledge of the area and environment. Make sure communication is clear and easily understandable, and respond to them constructively and with empathy.
  - ⇒ Ask the community how they would like to be communicated with. What works in one area may not work in another.
  - ⇒ Develop a public participation plan early, share it with landowners, and ask for comments and suggestions.
  - ⇒ Try to have one consistent contact person that landowners can call, and make sure that person is clearly identified to the public. Provide the land agent's name and number and also the supervisor at the company or a company hotline to call.
  - ⇒ Bear in mind first contact issues and their potential sensitivity to landowners - a call, a letter, a visit? Consider issuing a public notice in the local newspaper or on other media (television, radio) before contacting landowners for a survey so that landowners have some awareness of the project before they are first contacted.
  - ⇒ Post information and updates on town bulletin boards and other public places.
  - ⇒ Ask town officials for help contacting local stakeholders so it can be determined whether or not everyone impacted by the project has been contacted.
  - ⇒ Share where the company gets its information and what resources the company relies upon.
  - ⇒ Give people time to react to requests, documents etc. Don't expect overnight feedback.
  - ⇒ During the process, setup a feedback system so citizens know when they will get answers to their questions. Put answers to general questions on a web site or other public place so all citizens can see the information.
  - ⇒ Stay away from industry jargon: use language carefully and be aware of how the public perceives the company at all times. Using words like "marketing" in public settings can give the company a negative image because the word has different meanings to different people.
  - ⇒ Understand stakeholders' knowledge and background.
  - ⇒ Consider establishing an ombudsman for neutrality in information and contacts.
  - ⇒ Consider funding of studies requested by stakeholders.

Project Announcements and Ongoing Information Collection

- When announcing the project, be specific and thorough—carefully spell out the process and timeline for other stakeholders.

- When announcing the project, consider the most effective meeting types. Again, ask stakeholders how they want to be communicated with.

    - ⇒ Do they prefer open houses, or one-on-one meetings, or a letter first? Should the initial contact be formal or informal?
    - ⇒ Consider meeting locations and times. For example, in an agricultural area, don't hold a meeting in the planting/harvest season; or don't hold a meeting on a religious holiday; etc.
    - ⇒ Have qualified engineers and technical staff available to answer safety and design questions, perhaps with a sample piece of pipeline, to describe how it is designed and operated.

- For an open house, notify all stakeholders in the study corridor. Perhaps present a slide show on pipeline construction and other general issues so that people unfamiliar with pipeline siting and construction can get a clear idea of what is proposed.

    - ⇒ Describe the size and types of equipment that would be used.
    - ⇒ Ensure all documents are accurate and consistent. Avoid giving conflicting information to stakeholders.

> When announcing the project, consider the most effective meeting.

- Distribute the following information, whether in pamphlet-form or by other means:

    - ⇒ A general biography of the company,
    - ⇒ General information on environmental and other benefits of natural gas,
    - ⇒ Discussion of today's energy market and the need for expanded infrastructure,
    - ⇒ FERC background information,
    - ⇒ Discussion of pre-filing activities,
    - ⇒ Post-filing review process,
    - ⇒ Construction information,
    - ⇒ Safety information, plans for safety training and the company's past safety record, and
    - ⇒ Intended time frame for completing various activities (a project time line).

- Share the pre-filing process with landowners in detail so that they can better understand the steps and decide how to get involved.

- Suggest unbiased sources (academics, web sites, government statistics) that are not affiliated with the company so that stakeholders can get information that is trustworthy in their eyes. Avoid using the term “proprietary information” because it can raise suspicions and create distrust.

- Make sure that all of the information that is used and shared with the public (including maps, studies, etc) is current and up-to-date.
- Follow up on outstanding questions and let people know how the answers will be communicated.
- Conduct post-project interviews or evaluations with key stakeholders to make future improvements.

Make Route Development and Data Collection Easy and Understandable

Share the pre-filing process with landowners in detail.

The stage of the process where surveys are performed, data collected and routes proposed may be the most confusing and complicated for many stakeholders. When it’s time to do the detailed route planning, make sure the landowner knows what to expect and has given permission to proceed with the survey(s). Survey permission forms should be readable with full disclosure of survey requirements.

- ⇒ What does survey permission mean? Recognize and state clearly that landowner concurrence to allow a survey is not approval of a right-of-way. Know the difference.
- ⇒ Explain the types of surveys (crew size, survey methods).
- ⇒ Describe the work to be done (such as: is tree cutting or clearing required? Will test holes be dug?).
- ⇒ Ensure the survey corridor is wide enough to accommodate route variations.
- ⇒ Describe alternative routes the company considered in addition to the proposed route.

Explain Mitigation, Compensation and Benefits in Layman’s Terms

- Many landowners are unfamiliar with the rules, process, and procedure of how a right-of-way payment is made. So, explain the compensation/payment method to landowners.

  - ⇒ Explain the typical procedures which the landowner can expect will be used.
  - ⇒ Explain procedures and specifics around payments for easements - how are they determined?
  - ⇒ Share information about additional damage payment(s) made after construction
  - ⇒ Provide options of what a landowner could request as compensation.

- Explain the energy benefits which will result from the project, or other benefits which could be locally significant.
    - ⇒ Develop a benefits plan and educate stakeholders about local benefits of the project (i.e. payments to landowners, local tax payments, etc).
    - ⇒ If the landowner requests "side jobs," explain what is or is not allowed and how the job might be performed for the landowner.

- Since practices vary among different pipelines, it is important to be up-front about the company's usual custom and whether or not it involves monetary compensation. If any funding to aid public participation is available, tell stakeholders early.

Conclusion

The proper preparation and stakeholder involvement in the pre-filing process can make the entire process easier, quicker, and ultimately less expensive. The company's reputation with the community and involved agencies will benefit from a well-devised, well-executed participation plan.

Agency Action Options

Coordinate to Address Multiple Oversight Responsibilities

Numerous agencies (federal, state and local) have a role in natural gas facility siting. All serve the public and may have overlapping responsibilities. Agencies' focus on management and regulatory requirements span a very wide spectrum of cultural, natural, economic, educational, political, and other resource interests. As a result, different agencies may have conflicting priorities or responsibilities due to their unique focus and or function. What is ideal for one agency may be detrimental to another. The challenge here is to identify what is needed to avoid or at least minimize obstacles to providing coordination and service, and how to achieve better results early in the facility planning process. There are several steps to coordination, including addressing project issues early, discussing joint participation, defining agency needs early, and addressing mitigation needs as soon as possible.

Address Project Issues/Concerns Early for Better Results

With many agencies and potential overlapping needs, it is important to get your agency's interests into the mix early so your role is clearly defined and understood from the beginning. Some of the things agencies can do upon getting an initial contact from a company include the following.

- Know what project components will involve your agency.
- Get support from agency management to commit resources for early involvement
- Determine the lead federal agency (usually FERC) and lead state agency, if one, and provide a key agency contact to ask and answer questions early.
- Establish coordination and early participation procedures among agencies.
- Consider attending public meetings in order to provide your agency's perspective and explain your role in the process.

HAVE YOU:

- ✓ Identified where your agency should get involved?
- ✓ Gotten support from agency management?
- ✓ Identified key issues and information needs
- ✓ Decided on coordination procedures?
- ✓ Attended public meetings?

Consider Multiple Agency Coordination and Joint Participation

Coordination with other agencies can reduce timing for reviews and approvals.

- Encourage team permitting to improve your agency's internal and external processes. Team permitting could reduce redundant review and provide information concurrently to all interested parties.
- Federal agencies should coordinate regulatory review and approvals at the federal level early.
- State agencies should coordinate regulatory review and approvals at the state and local level early.
- Determine whether your agency has public notification rules and/or needs to hold public meetings. Consider whether another agency's meeting could fulfill the requirements. Agencies that must involve the affected public and stakeholders before making their recommendations and decisions.
- Even if your agency cannot commit to early involvement, know where to get information and stay informed.
- Consider creating a document that shows how agencies work with other agencies so citizens know how to work with the system.
- Consider creating an agency forum for discussion and resolution of common issues.
- If resources prevent agencies from timely responses or actions, consider third-party funding by the project proponent to assist the agency.
- Ensure that decision-makers and required technical staff are involved early in the process so that accurate issues and needs are reflected early and decisions can be made more accurately and quickly.

Define Agency Information Needs and Timing Requirements Early

It is very important to identify information and timing requirements as early in the process as possible. When issues about the project, the process, and likely conflicts or potential outcomes are defined and acted on early, the process can go more smoothly and efficiently.

- Be clear about what information your agency needs and when you need it—have your requirements published clearly. Examples may be specific route surveys, survey results, landowner information (approved or denied survey access, etc.), and timing of when all remaining information must be submitted.

- Identify where and when decisions will be made and who will make them.

- If there are any "show stoppers" identify them as soon as possible. Examples: If state/local agency code/regulations have siting guidelines or requirements that conflict with FERC's routing criteria, or would require use of established "utility corridors" that are not conducive to a proposed project's end points.

Identify "show-stoppers" as early as possible.

- Agencies should give early and honest feedback on route alternatives. Make sure you supply whatever information you have.

- Agencies should identify any known cumulative effects (both beneficial and adverse impacts) and any growth that will occur in the project area. These should include location and timing information about any known development or other projects in the vicinity of the proposed pipeline.

Address Mitigation Needs As Soon As Possible

If resource impacts are unavoidable, but can be mitigated or otherwise compensated for, identify potential options which satisfy your concerns, as early as possible.

- Identify if compensation will be required.

- Explain who is responsible for developing mitigation plans.

Conclusion

Although different agencies can often have conflicting priorities and responsibilities, early and effective coordination can help prevent obstacles. It is important to know how to get information and to decide early on how different federal, state, and local agencies will work together in the most effective manner.

Citizen Action Options

Citizens Have a Unique Role: Take Advantage of Your Opportunity to Participate

Citizens and landowners are unique in the natural gas pipeline siting process for several reasons. While the pipeline company is proposing the action, and the government agencies are actively involved in the permitting process, citizens are often passively swept into the process. While the pipeline companies and the agencies participate in the process in the context of doing their jobs, the citizens not only must take time off from their jobs to participate, but their stake in the outcome may be more personal; the project affects their own property and/or community.

The challenge for citizens is to develop resources that enable active engagement in the process, objective application of the process, easier identification of direct or indirect project benefits, and greater access to information. In order to be involved in the most productive way, citizens should get involved early and make an effort to understand the process.

Get Involved Early and Stay Informed

Every pipeline company and every natural gas pipeline siting project is different. Projects that are large or new take longer to plan than smaller expansions of existing systems. The difference can depend on geography, the company's culture and the type of community that may be impacted by the siting process. Getting involved early and staying informed is a citizen's best strategy for ensuring that their needs are met and their questions answered.

- As soon as you can become involved, seek out information pro-actively; don't wait for it to come to you. If you wait, you could lose an opportunity.
  - ⇒ Constructive participation will get you more answers and information. Participate from a foundation of knowledge and fact rather than emotion and rumors.

HAVE YOU:

- ✓ Identified Company contacts?
- ✓ Learned about the siting process?
- ✓ Checked the pipeline company's web site?
- ✓ Given feedback on how the company or agencies can improve communication?

- Let the company know if you are interested in participating in the planning stage (where the route is determined) and not just the permitting stage (where the route is reviewed by regulators and agencies).

- Recognize what information the companies are obligated to provide and what information is not available.

    - ⇒ Ask questions and follow through until they are answered to your satisfaction.
    - ⇒ Although you should be prepared to wait for answers, you should also balance that with being assertive when it comes to asking for information you should have.
    - ⇒ Lots of information is on web sites (companies, agencies); make use of it.
    - ⇒ See the Industry Action Options for information about what resources should be made available to citizens; ask about them.
    - ⇒ Make sure you get the project manager's name and contact information so that you have someone to call if you have questions.

SOME SOURCES OF INFORMATION INCLUDE:

- FERC Regulations
  18CFR380
- FERC Landowner Notification Rule
  18CFR157.6(D)
- FERC Website
  http://www.ferc.gov
- Interstate Natural Gas Association of America
  www.ingaa.org
- Companies' Websites
  http://www.ferc.gov/industries/gas/gen-info/pipecomp.asp

- Understand that your active participation in a company's project can add value. Regardless of your opinion, it is in the company's best interest to work with you rather than against you.

    - ⇒ Decide if you want to be involved in decisions regarding routing and/or construction impact mitigation.
    - ⇒ When you send in comments to FERC, also send a copy to the company so they are immediately aware of your opinions.

- Explore whether your local municipality, county, or citizen organization will represent you as a group.

- Know the name and phone number of the company land agent's supervisor or the number of the company/landowner hotline. Don't hesitate to call if you feel you are not getting answers or if you think you are being treated unfairly; the company wants to know.

- Consider asking the company if any aid to public participation such as reimbursement for time and expenses is offered so you can be involved in the process. Every company has a different approach to how to handle this so don't be surprised if the company _you are working with tells you it is against their policy to provide compensation for your time or expenses.

Your participation can add valuable project information to the pipeline company's planning process.

Do Your Homework to Ensure Your Involvement is Productive

The process of siting natural gas pipelines is complicated and involves lots of participants and details. The following can help you be sure you are informed about the process and how you can become a partner in that process.

Know the Participants

- Understand the mission and business plan of the company proposing the project.
  - Check their web site and public mailings.
- Understand the role and mission of the FERC and its processes.
  - Check the FERC web site at http://www.ferc.gov/for-citizens/my-rights/citizen-guides/citz-guide-gas.pdf
- Understand the role of federal, state, and local agencies.
- Understand how your first tier local government can work for you. Your local government or community may be able to be your advocate.

Know the Process

- Understand the concepts of eminent domain, federal preemption, and public convenience and necessity.
- Understand the process of the National Environmental Policy Act of 1969 (NEPA). It is a statute that requires a federal agency to be aware of the environmental impacts of its decisions.
- Understand that the pipeline company will respect you for your honesty, just as you respect them for theirs.
- Understand that the regulatory review and approval process may not move as quickly as

the agencies involved to ensure a smoother process.

- Find out what survey permission is and what survey companies do (e.g. number of days, extent of work, etc). Be informed.

Becoming a Partner

- Determine whether there are, or could be, direct or indirect benefits of the project to your community and to you personally.
- Your knowledge can help accomplish the goals of the company in a way that meets your needs at the same time.
- Allowing surveys is not the same as granting a construction easement. Consider allowing the company to complete its surveys on your property as they may document environmental or engineering constraints if they exist. You may seek the advice of counsel if you are concerned.
- Improve informational resources. If FERC's or a pipeline company's landowner brochure doesn't meet your needs, tell them and suggest ways to improve them.

TYPICAL TYPES OF SURVEYS INCLUDE:

- Civil surveys,
- Geotechnical surveys,
- Cultural resource surveys,
- Wetland delineation surveys, and
- Threatened and endangered species surveys.

Some types, (especially geotechnical and cultural resource surveys), typically require localized excavations at predetermined intervals.

All surveys require that the surveyor have access to the land. Once access is granted, various surveyors may visit the property intermittently over a period of time.

Conclusion

There are ways for interested citizens to get involved in the pre-filing stages of natural gas pipelines that could affect their community. It is important that all stakeholder groups work together to ensure that citizens are actively engaged in the process, understand direct and indirect project benefits, and have greater access to information. Early involvement and better understanding will increase public participation and allows citizens to make their views known.

FERC Staff Action Options

FERC'S Role as the Lead Agency

There are many questions regarding FERC's role in siting natural gas pipeline facilities and how FERC's process is connected to those at other agencies, particularly state agencies. Landowners clearly look to FERC to provide more information than is currently available. Further, natural gas companies look for additional help from FERC to coordinate the efforts of all the other permitting authorities. There are several action options that can address requests for greater staff participation and other resources to aid the various stakeholders in the planning process. Options include: making an effort to keep information up-to-date, offering training to share information, and committing to get involved in the process early.

Commitment to Providing Up-to-Date Information

The FERC staff can become involved in projects during the pre-filing stage.

- The FERC web site was revised in the spring of 2001 and represents a marked improvement in appearance and the organization of information. Although it is more user friendly and it's easier to find the information you need, no new functionality was built into the latest release. FERC is considering further upgrades. Comments received at the seminars regarding the web site included requests for:
    - ⇒ Summary and status information for major projects. The summaries could also include links to the applicants' project web site.
    - ⇒ Criteria, requirements, and documentation for getting approval for the NEPA pre-filing process.
    - ⇒ A "home" for pre-filing (pre-docket number) project information.
    - ⇒ State-by-state links to relevant agencies so landowners can use the FERC site to get local info.
    - ⇒ A guide on how to contact FERC and ask that they get involved in a project.
    - ⇒ A landowner chat room where subject matter experts could respond to questions.
    - ⇒ Other specific requests to solve problems such as retrieving filed information from the RIMS system.
    - ⇒ Data on future projects.
    - ⇒ A list of contacts if people have further questions.

- FERC staff and/or other resource agencies (the Energy Information Administration, PUCs) should work to generate information about the big-picture market for natural gas and the need for natural gas on a regional basis that could be presented to various stakeholder groups.

- During the decision-making process, FERC should be sensitive to the difference between survey permission and landowner support of a project.

- FERC should enhance the existing brochure "An Interstate Natural Gas Pipeline on My Land? What Do I Need to Know?" to include information such as:
    - ⇒ The availability of information on the FERC's web site.
    - ⇒ Resources available to landowners (e.g., INGAA web site).
    - ⇒ Materials that companies are required to provide to landowners and others under the Landowner Notification Rule - when it is provided and to whom.
    - ⇒ What types of routing changes and landowner benefits in easement agreements can be negotiated without FERC approval, as FERC will not be involved in easement negotiations.
    - ⇒ Clarification on how a landowner can become an intervenor.

- FERC should conduct exit interviews with landowners after each project that implements pre-filing involvement to better understand where problems were and how those problems were solved. Debriefings on completed projects could be used to determine improvements to future projects.

- FERC should prepare a scoping summary to address issues raised during scoping.

- Consider establishing a single point of contact to answer questions.

Training to Improve the Process

FERC will offer training (mainly for industry and consultants) on Revised Regulations for Environmental Reports (Minimum Environmental Filing Requirements). FERC is currently planning a series of training sessions; please see www.ferc.gov for session dates, locations, and other details. Training will also be offered on Environmental Compliance. FERC can also use these training sessions to provide information to professional participants and to disseminate information on new methods and protocols that improve the NEPA process.

A Commitment to Early Involvement by FERC Staff

- Improve programmatic coordination between the FERC and other permitting agencies to expedite natural gas projects.
    - ⇒ FERC can make staff available to attend agency coordination meetings either before or after the filing of an application (subject to staffing limitations).
    - ⇒ If needed, help develop interagency or project-related Memoranda of Understanding between FERC and interested agencies to establish jurisdiction and responsibilities.

> By getting involved early, FERC can help coordinate agency and citizen participation.

- FERC could help achieve consensus in route planning and issue identification and resolution at the earliest possible point (i.e., before the filing of an application). FERC is currently in the process of initiating pre-filing environmental reviews. It is likely that FERC's involvement in each project will be slightly different depending on the case-specific circumstances. Typically the goal would be to issue a draft EIS very shortly after an application is filed. Adequate time should be allotted in the pre-filing phase to conduct scoping meetings, field surveys, and to compile the reports that are required to support the coordinated review by agencies, FERC, and third-party consultants.

- As the lead federal agency, FERC could advise other agencies of their role in the pre-filing application process.

- FERC should consider expanding its process to include giving responses to all levels of government officials. This response policy would help pipelines in addressing issues at the local level.

Conclusion

FERC could provide more information to stakeholders and coordinate efforts among agencies. FERC's early involvement should improve communication between stakeholders and could expedite the process.

Glossary

Construction easement

The area of land, or "footprint" that is disturbed or used for construction of the pipeline. This area is typically larger than the "permanent easement" and includes extra work areas for activities such as equipment staging, topsoil storage, stream and road crossings, and right-of-way access during construction.

Construction impact mitigation

Those measures that are implemented in order to reduce or undo the potential damages incurred during pipeline construction such as soil erosion on slopes that have been cleared and graded. In this example, water bars or slope breakers could be installed across the slope to minimize erosion caused by precipitation and the resultant siltation of nearby streams. State and Federal agencies often attach many construction mitigation requirements to their licenses and permits.

Draft EIS

A draft Environmental Impact Statement issued by the lead federal agency for a 45-day comment period.

Easement agreements

The legal document, signed by both the pipeline company official and the landowner, that specifies the route, work areas, amount and method of payment, if any, and other terms such as restrictions on the use of the land, and possible future expansions of the pipeline.

Easement and damage payments

Payments made by the pipeline company to the landowner or land-managing agency for the easement or damages resulting from pipeline construction. Damage payments, if necessary, would be in addition to standard payments for the right-of-way easement.

Easement negotiations

Those discussions between pipeline-company official and landowner about the specific terms of the easement that may or may not result in a signed agreement. These discussions are usually conducted by land agents representing the pipeline companies.

Eminent domain

The right of a government to seize private property for public use in exchange for payment of fair market value.

Energy Information Administration (EIA)

The Energy Information Administration (EIA), created by Congress in 1977, is a statistical agency of the U.S. Department of Energy. They provide policy-independent data, forecasts, and analyses to promote sound policy making, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment.

Environmental review

From the Federal perspective, implementing the independent review, agency consultations, and scoping out of issues that are part of administering the mandates of the National Environmental Policy Act (NEPA). Depending on the project's size, complexity and level of controversy, this review may take between three months to over one year.

Federal preemption

With respect to natural gas pipeline systems under the jurisdiction of the FERC, this broad legal concept means that Federal authority supersedes the state or local authority.

Formal certificate review

The formal review of an application under the Natural Gas Act which considers, in addition to environmental issues, rates, markets, financing, and other business issues.

Independent System Operator (ISO)

Organizations that manage the transmission portion (as opposed to the generation portion) of the electric industry.

Intervenor

Someone who wishes to participate in a proceeding and therefore files a petition to intervene with the Commission for a particular case. In their filing, an intervenor may additionally state whether or not they wish to protest the application and whether or not they seek a formal hearing on the application.

Land agents

Those representatives of the pipeline companies who are dispatched to acquire the right-of-way for the proposed pipeline project.

Lead federal agency

When more than one federal agency has permitting authority for a project, the agencies often designate a lead Federal agency to supervise the preparation of the EA or EIS. The FERC is frequently the lead Federal agency for natural gas pipeline projects.

Open season

A process in which a pipeline company solicits market interest for new pipeline transportation services. This is done as part of the pipeline company's planning process to help it determine the economic feasibility for a project.

Pre-filing time frame

The period of time before an application is filed at the FERC.

Public convenience and necessity

Synonymous with "for the good of the general public". Generally, if the Commission determines that there is sufficient need for a project after the consideration of all relevant factors, then it is determined to be in the public convenience and necessity and, it will be processed and issued a "certificate of public convenience and necessity" or license. These "certificates" carry with them the power of eminent domain.

RIMS

The Record Information Management System (RIMS) is the database where case-specific information is stored electronically. It is accessed via the Internet at www.ferc.gov.

Route variation

Relatively small deviations from the proposed route that are meant to avoid some environmentally sensitive area. Route variations usually depart from and then rejoin the proposed route within a short distance.

Scoping

In the context of NEPA, scoping is the process of asking the public and other agencies to identify any environmental issues that should be considered in the environmental analysis of the pipeline project.

Side jobs

Activities which are not related to work required for the pipeline construction but which the pipeline company may be willing to do for a landowner as part of the easement negotiation.

Survey

Typical types of surveys include civil surveys, geotechnical surveys, cultural resource surveys, wetland delineation surveys, and threatened and endangered species surveys. Some types, especially geotechnical and cultural resource surveys, typically involve localized excavation at predetermined intervals in order to collect the desired data. The other types of surveys usually only involve walking the pipeline right-of-way, taking measurements and observations and may involve taking small samples such as soil and plant samples. All surveys require that the surveyor have access to the land being surveyed. Survey permission forms may be used to document landowner agreement to allow access. Once access to the land is granted by the landowner, surveyors may visit the property intermittently over a period of time.

Team permitting

An approach that some states have adopted to issuing the many various environmental permits for a particular project whereby the agencies involved coordinate with each other (and the applicant, public, and cooperating agencies) and issue all their respective permits in one action.

Test holes

Small excavations or borings performed in the process of surveys such as cultural resource surveys or geotechnical surveys.

APPENDIX 6
Analysis of Carbon Capture And Sequestration Potential

ANALYSIS OF CARBON CAPTURE AND SEQUESTRATION POTENTIAL
TASK 5A

Prepared for VSE Corporation

NETL Cooperative Agreement # DE-FC26-06NT42449

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CHAPTER 1: INTRODUCTION

1.1 Overview

The scope of Task 5A is to identify and evaluate the potential for geologic sequestration in the South Shore, Kentucky area. This task evaluates likely transportation costs and issues associated with carbon storage via pipeline and likely rock layers (storage units) in the Southeast Ohio – Northeast Kentucky region.

The US Department of Energy (DOE) Office of Fossil Energy National Energy Technology Laboratory (NETL) has produced the Carbon Sequestration Atlas (2008, 2nd Ed.), which provides a detailed overview of carbon storage across the United States. As a companion, NETL continuously updates their website (http://www.natcarb.org/index.html) to reflect the work progress described in the Atlas. For background information on national carbon storage issues and research, this would be a good source.

This report has taken general information supplied by NETL and provided additional site specific data for the Southeast Ohio-Northeast Kentucky region, where it is available. The report evaluates carbon dioxide transportation and storage in this region.

In general, carbon dioxide can be transported in refrigerated tank cars, trucks, barge and pipelines. However, to move large amounts of carbon dioxide without interruption from the point of capture to the point of sequestration, a pipeline is the most economical means of transport and is being used by the oil industry to transport carbon dioxide from natural sources to oil fields for enhanced recovery. Chapter 2 will focus on issues associated with transporting carbon dioxide from industrial sources by pipeline.

The storage of carbon dioxide (geologic sequestration) is evaluated in Chapter 3. While carbon dioxide has been used for decades for enhanced oil recovery (EOR) in the western United States, the industry has not developed criteria for monitoring and verification of long term storage. In addition, oil and potentially gas reserves do not have enough capacity to store all the carbon dioxide currently emitted. Geologists and engineers are researching other geologic formations that can be used to store carbon dioxide over several thousand years. This report discusses the most viable geologic formations to store carbon dioxide in the region of northeastern Kentucky and southeastern Ohio Geologic data has been compiled and interpreted by the Kentucky Geological Survey (KGS) and SMG staff. Sources for the information were made available by the KGS and Ohio Geological Survey (OGS).

Conclusions are provided in Chapter 4 based on the evaluations in Chapter 3 for the potential for sequestration. As more research and projects are completed, the estimates presented within this report can be refined.

CHAPTER 2: CARBON DIOXIDE TRANSPORTATION

2.1 Overview of Carbon Dioxide Transportation

To deliver carbon dioxide from the plant to the storage site for either storage or enhanced oil recovery (EOR) and enhanced gas recovery (EGR), transportation must be available and economical. The South Shore site is located on the Ohio River, the main CSX rail line, and Highway 23. The site has remnants of a rail loop; and there are 11 cells remaining in the Ohio from the former Eastern Terminal Coal facility at the site. Site development plans are to rebuild both the barge facility and rail loop. Gasification facilities measure their product by barrels produced, the following table shows a comparison of the possible transportation media for a 10,000 barrel per day (BPD) facility. A 10,000 BPD site would produce approximately 8,217 tons of carbon dioxide emissions per day or approximately 3 million tons per year.[1]

CO_2 Transportation Overview

	Rail (tank car)	Truck	Barge	Pipeline (14 to 12 inch line)
Capacity of one unit	**80 tons**	**20 to 24 tons**	**1200 tons**	**Approximately 8800 tons Daily***
Number of Units to hold 1 day of CO_2 Emissions (based on 8,000 TPD)	**100**	**334 to 400**	**6.7**	

*Dakota Gasification Company (Dakota Gas) sends super-critical CO_2 from its Great Plains Synfuels Plant through a 205-mile 14-inch and 12-inch carbon steel pipeline to an oilfield near Weyburn, Saskatchewan, Canada. It currently sends 8,000 metric tonnes at 152 bar using two compressors.

The use of trucks would be least efficient in transporting carbon dioxide from the site. While barges have greater capacity than rail or truck, carbon dioxide barges are not currently manufactured in the United States. Therefore, this section will concentrate on transportation by pipeline. Transportation of carbon dioxide by pipeline is currently the most common and economical method for transporting large quantities over modest distances.

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[1] Technologies for Producing Transportation Fuels, Chemicals, Synthetic Natural Gas and Electricity from the Gasification of Coal. Center for Applied Energy Research. July 2007.

2.2 Pipeline Transportation

The movement of carbon dioxide by pipeline will require a pipeline system which will be closely linked to its storage. According to the National Pipeline Mapping System there are no carbon dioxide pipelines in the state of Kentucky or in close proximity to the site, but there has been legislation passed in Kentucky in preparation for planning and construction of a carbon dioxide pipeline.[2] The legislation and regulatory work required to develop carbon dioxide pipelines in Kentucky are discussed at length in a companion report.

This chapter will focus on construction and construction issues associated with a carbon dioxide pipeline. The majority of all carbon dioxide pipelines in the US are located in the south central region, where carbon dioxide is pumped from a natural source and used primarily for enhanced oil recovery projects. Issues not associated with these pipelines such as water content, locations in populated areas and transportation pressures will require research and design parameters for carbon dioxide from man-made sources.

2.2.1 Overview of Compression and Transport Process

For this report, we have included the cost of compression in the overall cost estimates of transporting carbon dioxide. Once the carbon dioxide is captured, it is compressed from 0.1 megapascal (MPa) to 15 MPa. The pascal is the standard unit of pressure and is equal to about ten atmospheres. The number of compressor stages to achieve the new pressure will vary, but we can assume five compressor stages[3]. Based on current technology, one compressor train will consume 40 megawatts (mW) of electricity during a compression cycle.

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[2] Kentucky Revised Statute 353.750.

[3] McCollum, David L. and Joan M. Ogden (2006) Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity. Institute of Transportation Studies, University of California, Davis, Research Report UCD-ITS-RR-06-14.

Once the carbon dioxide is compressed then the gas must be pumped through the pipeline. The following table illustrates the power requirements for the compression and pumping of the carbon dioxide[3].

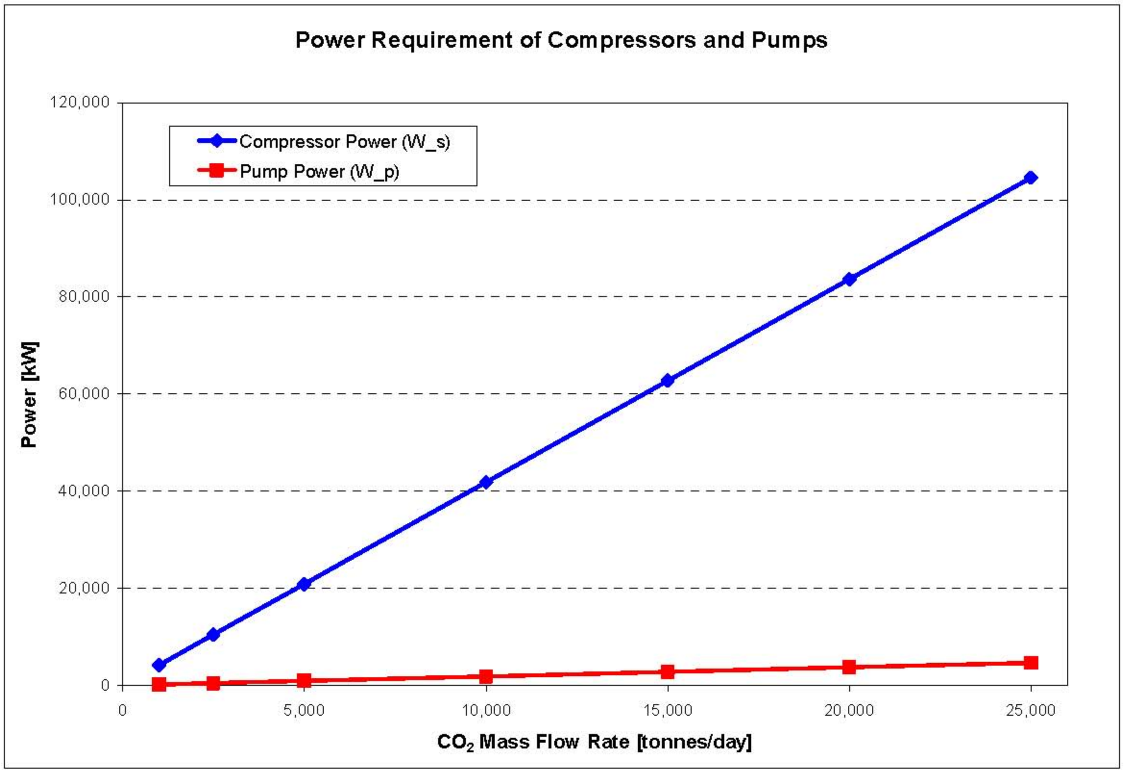

Figure 1: Power Requirement of Compressors and Pumps as a Function of CO_2 Mass Flow Rate

As you can see, power requirements for pumping and compression are significant and should be considered in the cost of construction and operation of a pipeline.

2.2.2 Construction and Operating Costs

Carbon dioxide pipeline cost-construction models developed at Carnegie Mellon University determined the capital costs would be approximately $6,000,000 to construct an 11-mile pipeline in the Midwestern United States with a transmission capacity of 10 million tons of carbon dioxide annually, which is about 3 times what our site would have. The cost would be approximately $0.10 per ton of transported carbon dioxide, including costs for compression, which includes a 0.15 capital recovery rate per year.[5]

Using the carbon dioxide pipeline transport model developed by MIT (Massachusetts Institute of Technology), Carnegie Mellon researchers estimated an ongoing cost of $0.34 per ton of transported carbon dioxide, with 92 percent being capital costs and 8 percent being O&M[4]. This estimate is for a 30-km (18.6-miles) pipeline and a mass flow rate of 4,670 tons per year (tpy) in Central Alberta, Canada.

A study from the University of California provides a breakdown of costs in terms of percentage of total construction costs.

> *A University of California study analyzing the costs of U.S. transmission pipelines constructed between 1991 and 2003 found that on average, labor accounted for approximately 45% of the total construction costs. Materials, rights of way, and miscellaneous costs accounted for 26%, 22%, and 7% of the total costs, respectively. Carbon Dioxide (CO_2) Pipelines for Carbon Sequestration: Emerging Policy Issues (2007).*[5]

McCollum, et al (2006) calculated the annual O&M costs to be 2.5 percent of the total capital cost. This value holds true in their model over a wide range of flow rates and pipeline lengths.

These studies indicate there is a large range of cost estimates generated by researchers. As pilot projects move forward with geologic storage, researchers will be able to predict costs more accurately.

Both Denbury Resources Inc. and CH2M Hill have announced carbon dioxide pipeline projects this year. Denbury plans to build a pipeline from Donaldsonville, Louisiana to a mature oil field between Houston and Alvin, Texas. CH2M Hill announced it has been awarded a contract to build a 230-mile pipeline from Lost Cabin Gas Plant in Wyoming to the Bell Creek Field in southeastern Montana.

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[4] McCoy, Sean T., Rubin, Edward S. (2005). Models of CO2 Transport and Storage Costs and Their Importance in CCS Cost Estimates. FOURTH ANNUAL CONFERENCE ON CARBON CAPTURE AND SEQUESTRATION DOE/NETL PROCEEDINGS MAY 2-5, 2005.

[5] CRS Report for Congress, (2008). Pipelines of Carbon Dioxide Control: Network Needs and Cost Uncertainties.

These will be EOR projects, but can provide updated costs and construction information for later sequestration projects.

2.2.3 Financing

In 2007, House Bill 102 (HB 102) was adopted by the Kentucky Legislature. HB 102 granted the Kentucky Gas Pipeline Authority the power to facilitate carbon dioxide pipeline projects. The primary purpose of the Kentucky Gas Pipeline Authority is to provide a financing mechanism for the construction, improvement or repair of any gas pipelines or appurtenant facilities. Financing mechanisms include the issuance of state revenue bonds, and notes.[2]

With financial assurance, a carbon dioxide pipeline could commence. A pipeline project will fall within the Kentucky Gas Pipeline Authority's jurisdiction, which has been granted the power to acquire property, rights, easements, and other interests to facilitate the construction of the pipeline project.[6]

2.2.4 Pipeline Construction

According to Barrie et al., typical pipeline-engineering considerations include: pressure, temperature, gas mixture composition, corrosivity, and pipeline control. [7] These parameters effect construction and costs. This section provides a summary of those issues.

The most used operating pressure is between 7.4 and about 21 MPa. Above 7.4 MPa, CO_2 exists as a single dense phase over a wide range of temperatures. Clearly a transmission pipeline can experience a wide range of ambient temperatures, so maintaining stability of this single phase is important in order to avoid considerations of two-phase flow that could result in pressure surges. Two-phase flow means the CO_2 exists in the pipeline as both a gas and a solid causing "dry-ice" build up.

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[6] Kentucky Revised Statute 353.756

[7] Barrie, J., Brown, K., Hatcher, P.R., Schellhase, H.U., CARBON DIOXIDE PIPELINES: A PRELIMINARY REVIEW OF DESIGN AND RISKS, University of Regina (2009).

Contamination of the carbon dioxide gas can have catastrophic effects in the pipeline. Contamination can simply be water vapor in the gas mixture. Too much water causes development of carbonic acid in the pipe, which will lead to deterioration of the pipe material leading to a rupture. Water vapor can also cause phase shifts in the pipeline (freezing, ice formation). For transport and storage purposes the carbon dioxide gas needs to be 98 percent pure.

As an example, the risk to humans from a pipeline rupture must be assessed and planned for responses. Barrie et al suggests a need for Emergency –Response Planning.

> *"Knowing that most CO_2 pipelines may have a number of incidents per year, designers must ensure that adequate procedures are in place to handle leaks and that there is a review process with an emergency-response (ERP) team during the risk-review study. Odorization of CO_2 in pipelines appears to be a necessity to ensure that there is early detection of leaks. The disadvantage with this detection approach is that there may not be an increase in the odor level to indicate when lethal limits are being approached. Special precautions and design elements need to be investigated and incorporated as necessary. It is critical that a thorough study be made of the routing, terrain, and seasonal effects, to ensure that a good dispersion study is performed to assist the ERP team to immediately identify evacuation needs."*[7]

In Europe, Det Norske Veritas (DNV), with industry partners, is developing new guidelines for design and operation of onshore and offshore pipelines for the transmission of carbon dioxide. According to DNV,

> *"There are various codes and standards available that are applicable to pipeline design and operation including the U.S. Federal Code of Regulations, ASME Standards B31.4 and B31.8, IP6, BS EN 14161, BS PD 8010, ISO13623, API RP1111 and DNV OS-F101. The guideline under development will provide specific guidance with respect to CO_2 and will supplement the existing pipeline design standards."*[8]

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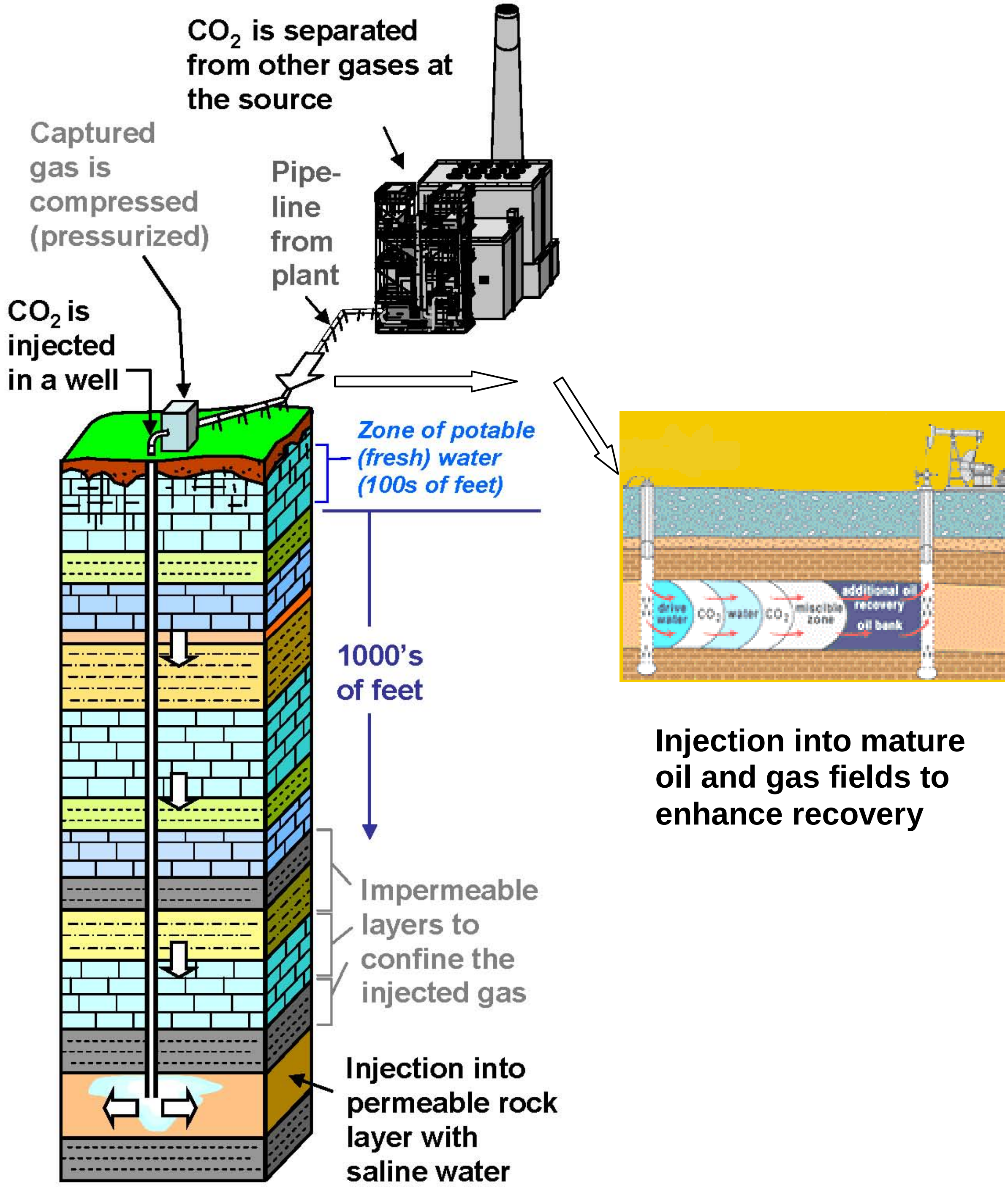
[8] Frøydis Eldevik, 2008, Safe Pipeline Transmission of CO2 , Det Norske Veritas (DNV). November 2008 Vol. 235 No. 11

As the carbon dioxide transportation industry further develops, it is expected that new guidelines will be incorporated into industry standards and regulation.



Source: KYCCS (2008)

3.1 Overview of Carbon Storage

Passive sequestration is the most economical method for carbon dioxide storage, and includes enhanced oil recovery (EOR) and enhanced gas recovery (EGR). Since reuse of carbon dioxide can be limited, the report discusses geologic sequestration, storage at depths below 2500 feet.

The geologic study area includes all of Greenup and Carter Counties in Kentucky and Scioto County, Ohio. In addition, the study area includes portions of Lewis, Rowan, Elliott, and Boyd Counties (Ky.) and Adams, Pike, Jackson, and Lawrence Counties in Ohio **(see index map)**.

Information presented in this section is based on regional research and limited local information from well logs and literature. As research continues, information presented here will be refined and is expected to be confirmed. Information on storage in unproven reservoirs is presented with the understanding that testing in these areas will be required.

More detailed studies of the region are provided by Midwest Regional Carbon Sequestration Partnership (MRCSP) (http://216.109.210.162/ PhaseIReport.aspx) in their Phase I Final Report 2003-2005 (December 2005), the Ohio Geological Survey (http://www.dnr.state.oh.us/Default.aspx?alias=www.dnr.state.oh.us/geosurvey), and KGS along with the Kentucky Consortium for Carbon Storage (KYCCS) (http://www.uky.edu/KGS/kyccs/). Regional information concerning specific characteristics of geologic units has been obtained from these sources.

The following data and sources were compiled for the study:

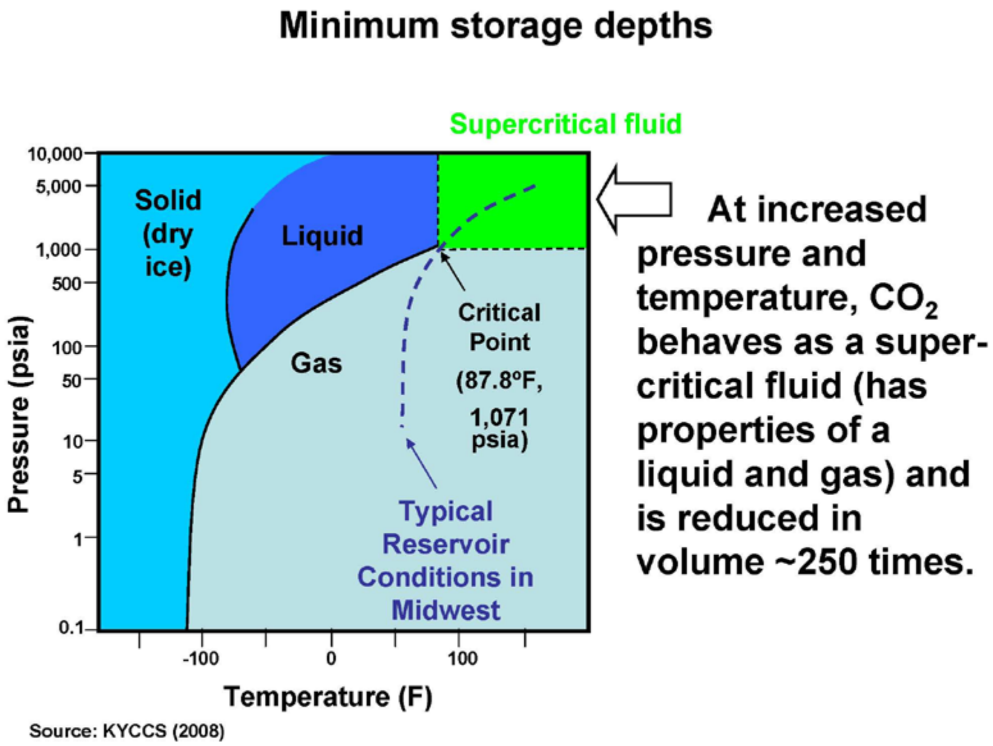
1. Locations of all oil and gas, and waste disposal wells penetrating the Cambro-Ordovician Knox Group or deeper (Kentucky and Ohio Geological Surveys)
2. Formation tops for geologic units from the top of the Ordovician to Precambrian (Kentucky and Ohio Geological Surveys)

3. Available digital geophysical logs for Knox and deeper wells (Kentucky and Ohio Geological Surveys)
4. Digital oil and gas field maps for Kentucky and Ohio (Kentucky and Ohio Geological Surveys)
5. Public domain reflection seismic data (2 lines in Greenup County, Kentucky)
6. Various geologic and engineering data from the Aristech Class 1 hazardous waste disposal site in Scioto County, Ohio (obtained from Ohio Geological Survey)

3.1.1 Physical Properties of Carbon Dioxide

It is important to understand the basic properties of carbon dioxide in the geological system. This section briefly describes its characteristics. For more detailed information, research papers are available on this topic. For purposes of understanding sequestration potential, the following information is provided.

Carbon dioxide can exist in four phases: solid, liquid, gas, and super-critical gas. At pressures greater than 1,071 psia (pounds-force per square inch absolute) or 7.38 MPa, and a temperature of 87.8 °F carbon dioxide is a supercritical gas, which acts as a gas that fills available space but has a density of a liquid. The higher density of the super-critical phase means more carbon dioxide can be stored in the same volume than the gas phase. Depending on actual temperature and pressure of the sequestration target, storage capacity can be several hundred times larger.



Minimum storage depths

At increased pressure and temperature, CO_2 behaves as a super-critical fluid (has properties of a liquid and gas) and is reduced in volume ~250 times.

Source: KYCCS (2008)

As reported by MRCSP, given the following assumptions about this geographic region, carbon dioxide becomes supercritical at approximately 2,500 feet below surface.

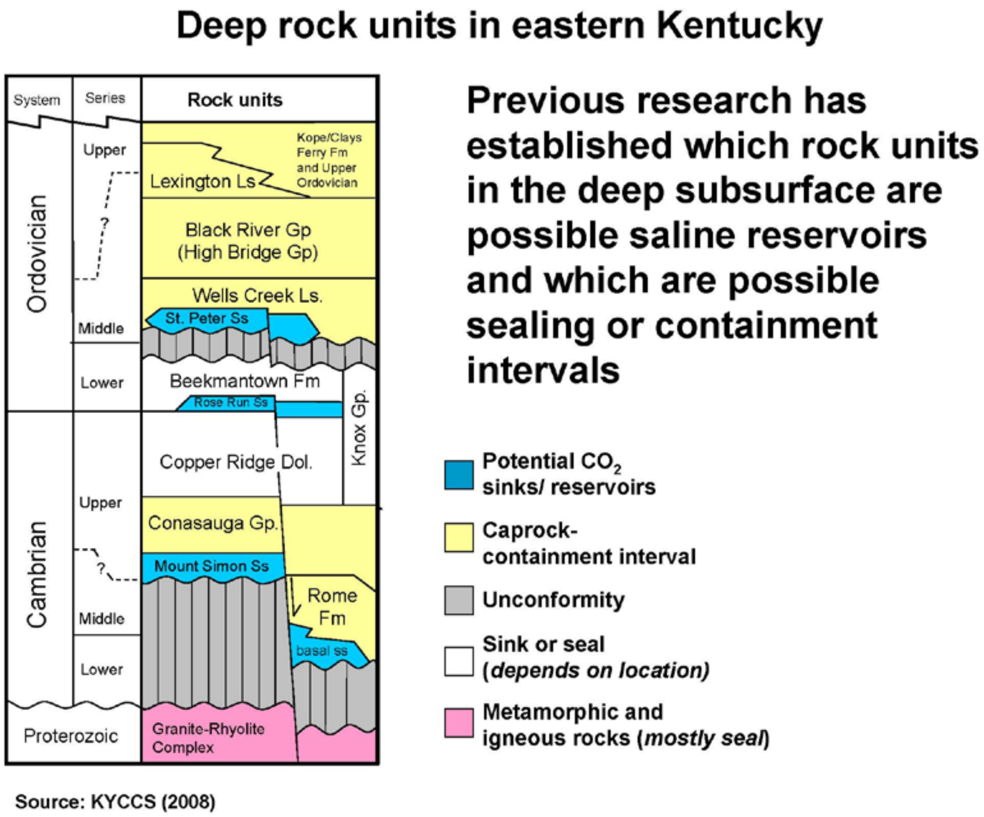
- Average surface temperature of 56 °F, and 14.7psia at sea level or 0.1 MPa
- Pressure gradient 0.433 psia/ft (increasing with depth) or 0.003 MPa/ft
- Temperature gradient 0.01 °F/ft

Therefore, storage of carbon dioxide at depths shallower than 2,500 feet will be in a gaseous state, and depths deeper than 2,500 feet will be as a super-critical gas. For comparison, at standard temperature and pressure carbon dioxide has a density of 0.1124 lbs/ft^3 while at the critical point it has a density of 29.09 lbs/ft^3, which means that more CO_2 can be stored in the same volume when it is in the supercritical stage.

Other physical properties of carbon dioxide include its ability to dissolve in brine (salt) water. As the salt concentrations increase, the ability for carbon dioxide to dissolve in the brine decreases. This is important in the saline aquifers being evaluated as target formations.

3.2 Geologic and Geographical Setting

The storage of carbon dioxide will be within sedimentary rocks, such as sandstones and limestones, with higher porosity and permeability. The sedimentary rocks, such as shales and some limestones with low porosity and permeability, are used to trap the carbon dioxide and are located above the storage zones.


Deep rock units in eastern Kentucky

Previous research has established which rock units in the deep subsurface are possible saline reservoirs and which are possible sealing or containment intervals

Source: KYCCS (2008)

3.2.1Geographical Setting

South Shore, Kentucky is located in northeast Kentucky along the Ohio River and downstream from Ashland (**Figure 1**). It is the western part of the Appalachian Basin and part of the Ohio River Valley. This area is characterized by flat floodplains of the Ohio River to the north giving way to rolling hills (foot hills) of the Appalachian Mountains. South Shore is located along the Ohio River at river mile 351.0 and the site is within this flat floodplain area.

3.2.2 Geological Setting

South Shore is near the Waverly Arch which trends north-south through Northeastern Kentucky. The Waverly Arch appears to have been active during the late Cambrian and Ordovician during deposition of the Beekmantown formation.

Since South Shore is on the arch (upwarping) as opposed to part of the Rome Trough (downwarping), the depth to basement granitic rock is less. In this area, basement is between 5,000 and 6,000 ft. Further to the north and south and east the basement rock can be at a depth of greater than 8,000 feet below the surface. Basement is the lowest elevation that CO_2 can be stored since the granitic rocks do not have pore space for storage.

3.3 Geologic Storage Units

Over the last several years regional formations have been identified by KGS as potential targets for sequestration of carbon dioxide. Organizations such as the Midwest Regional Carbon Sequestration Partnership (MRCSP), which includes the Kentucky Geological Survey (KGS), have begun compiling existing information and researching formations with regional distribution and the potential for storing carbon dioxide. Test wells for deep sequestration in this region have been conducted in Ohio, West Virginia and Kentucky. Information gathered from these tests will provide a better understanding of the geology and its capabilities for storing large amounts of carbon dioxide over long periods of time.

Based on experience in the oil and gas industries, scientists have been focusing sequestration research on saline aquifers where good permeability and porosity are present. As research has developed, the focus on sequestration targets has broadened to include the Devonian Shale and Knox dolomites.

3.3.1 Enhanced Oil and Gas Recovery

Oil and gas production is of interest in carbon storage because these areas offer potential to use CO_2 in enhanced oil and gas recovery (EOR and EGR), thus providing revenue to the CO_2 producer. EOR and EGR have been used successfully in the West Texas Permian Basin using carbon dioxide shipped via pipeline from Colorado. These fields are extensive and deep in comparison to those found in Eastern Kentucky and Southern Ohio. EOR and EGR have not been extensively tested in this part of the U.S. Most of the oil and gas producers are small companies with little capital to invest in testing carbon dioxide. Therefore, the most attractive fields for carbon storage will be mature fields that have used water flooding in the past and have data to support testing carbon dioxide.

The locations of oil and gas pools in the study area are shown on the oil and gas pool map (**Figure 2)**. Red outlines on the oil and gas map indicate gas fields and green outlines indicate oil fields.

North of South Shore, In Ohio, production is entirely natural gas. The primary reservoir is the Devonian Ohio Shale, an unconventional reservoir that serves as both the source of the gas and the reservoir. Natural gas (primarily methane) occurs in pores in the rock, and is adsorbed on clay and kerogen surfaces. This is analogous to methane that is attracted to organic matter in coal beds (coalbed methane). Work by Nuttall (2005) has shown that carbon dioxide can also be adsorbed onto the organic matrix in black shales, and has a much stronger adsorption capacity than methane. While still in the experimental stage, there is a possibility that injection of carbon dioxide into the Devonian shale will result in adsorption and trapping of carbon dioxide with displacement of additional methane into producing wells. This mechanism of enhanced gas recovery has been demonstrated in coalbed methane wells in the San Juan Basin of the southwestern US. The validity of this concept in organic shales will be tested by the KYCCS in the next year.

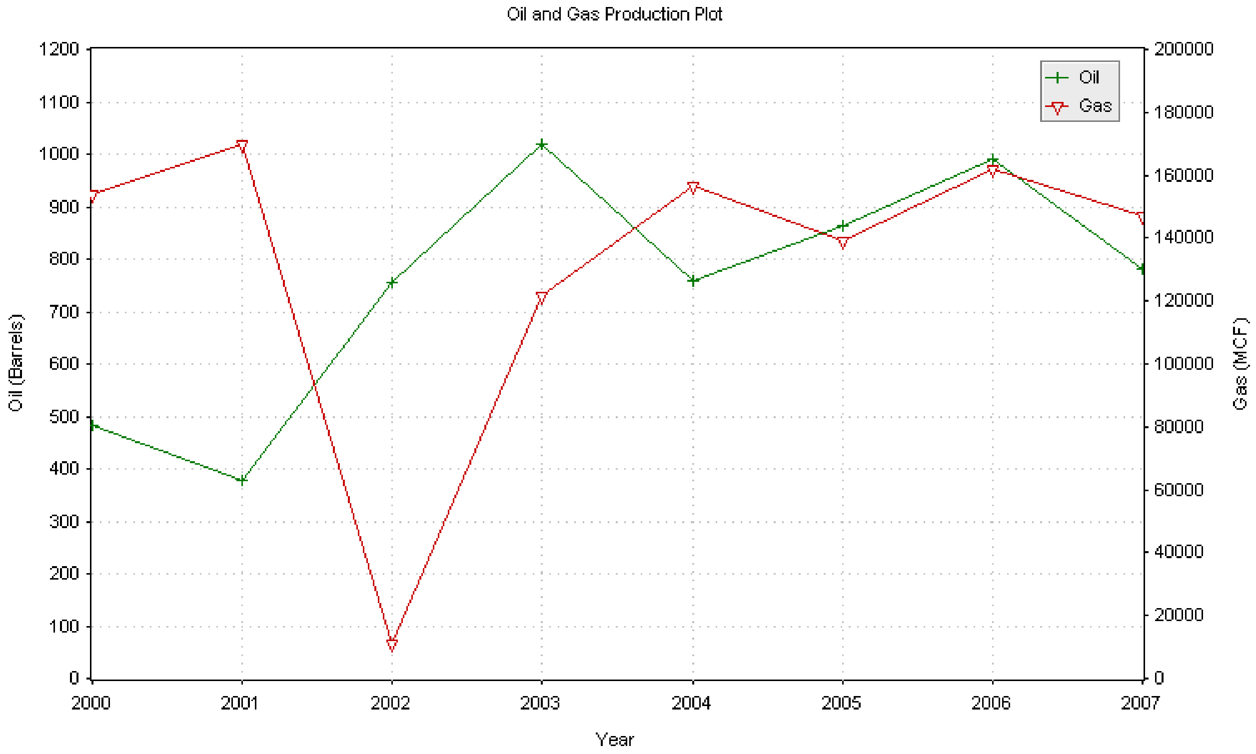
The gas pools in Scioto County, Ohio produce from the Devonian Ohio Shale and the Mississippian Weir (Borden Formation.). The pools in Pike and Jackson County, Ohio are primarily Devonian shale producers. Gas is produced from Silurian Clinton sandstones in Lawrence County. Production data from these counties is available from the Ohio Geological Survey, but was not reviewed for this study. The Ohio gas fields may offer potential for the use of carbon dioxide in enhanced gas recovery, but the viability of this technique in organic-rich shales has not been proven.

The Devonian Ohio Shale also produces natural gas in northeast Kentucky, primarily from the two pools in Boyd County, the Ashland and Mavity fields. These fields produce gas from Pennsylvanian Salt Sands, Mississippian Maxon, Big Injun, and Berea sandstones, and the Devonian Ohio shale. The Ashland field has also produced oil from the Corniferous interval. The Devonian shale reservoir in the

Ashland field would provide the largest target for EGR in the area around South Shore. The field lies about 25 miles from South Shore (to the center of the field). Boyd County produced almost 150,000 MCF (thousand cubic feet) of gas in 2007, the latest year for which data are released (see chart below). The production data is not broken down by field, but more detailed production data is available at the Kentucky Division of Oil and Gas Conservation's web site: http://www.dogc.ky.gov/ .

Both the Ashland and Mavity fields had active production in 2007. Annual oil and gas production for the period 2,000 to 2,007 is shown on the chart below.

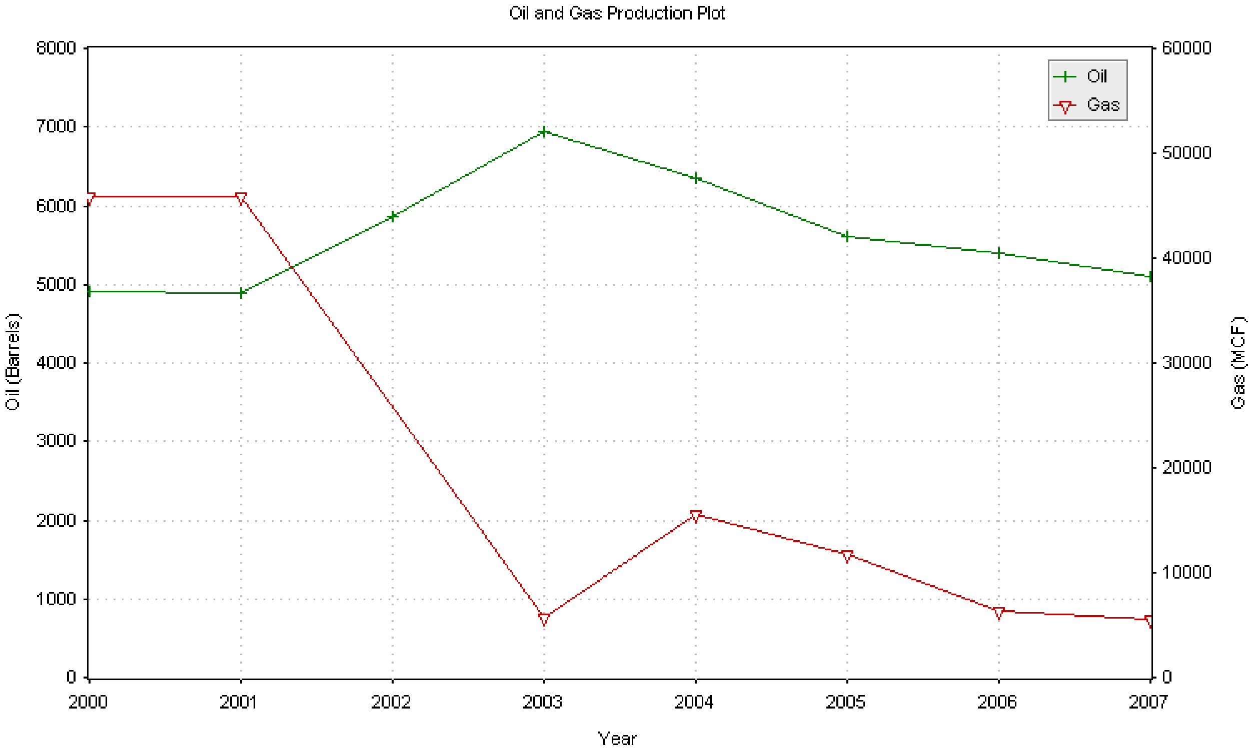
Boyd County Production, 2000-2007



Part of the Ashland gas pool lies in Greenup County, but oil production is more important in Greenup than in adjacent Boyd County. Greenup County, south of South Shore, has produced between 5,000 and 7,000 barrels of oil per year over the 2000-2007 period. This production is from several small fields including Naples, Hunnewell South, and Ashland. Other older fields in Greenup include Warnock, Oldtown and Oldtown West. Some of these fields may be suitable for carbon dioxide

EOR, but an evaluation of individual fields is beyond the scope of this project. The fields are small and shallow, which means carbon dioxide will remain in a gas phase in the reservoir, rather than a true miscible flood where greater enhancement of oil production occurs. Oil production is primarily from the Berea and Weir sandstones at depths less than 1,500 ft. Annual oil and gas production from Greenup County is shown on the chart below.

Greenup County Production, 2000-2007



Neither Carter nor Lewis Counties reported oil or gas production in the time period 2000-2007. The state of Kentucky has no production records for Lewis County. The pools shown there date to the early 1900’s and are abandoned. Carter County reported minor oil production in the 1980’s and early 1990’s, but no gas production. The oil production was 60-200 barrels per year, and it is assumed that these wells are now abandoned. Because we have no record of gas production in Carter County, the gas pools shown on the map are assumed to pre-date state production records, and are likely abandoned.

To summarize, carbon dioxide storage and enhanced gas recovery may be possible in the Devonian Ohio shale gas fields in Scioto and Jackson Counties, Ohio and Boyd and Greenup Counties in Kentucky. This potential will not be known until further research and testing is completed in Kentucky. Enhanced oil recovery targets occur primarily in Greenup and Boyd Counties, Kentucky. These gas and oil pools lie within 25 miles of South Shore. The economics of using carbon dioxide for EOR and EGR in this area will have to be carefully evaluated.

There is no existing pipeline infrastructure to transport the CO_2 to the fields, and some reservoirs may not be suitable for EOR/EGR for geologic reasons. The size of the EOR/EGR targets may not justify the cost of implementing CO_2 projects. There are lower cost CO_2 EOR options than building a pipeline for continuous injection. On example is a cyclic injection (huff ‘n puff), where smaller volumes of trucked CO_2 are injected into a producing well and allowed to react with the reservoir. These types of treatments may offer a limited market for CO_2 produced at an industrial site in South Shore.

3.3.2 Deep Geologic Storage Targets (>2,500 ft)

Geologic storage of carbon dioxide is commonly proposed to occur at depths of 2,500 ft below the surface so that CO_2 is in a supercritical phase, and can be stored in much higher concentrations. In the Greenup County area, potential injection zones below 2,500 ft include from top to bottom (**Figure 3**):

1. Ordovician St. Peter Sandstone
2. Ordovician- Cambrian Knox Group
    - Beekmantown Dolomite,
    - Rose Run Sandstone, and
    - Copper Ridge Dolomite
3. Ordovician Rose Run Sandstone
4. Cambrian Mt. Simon/basal sandstone

These porous intervals are confined by several seals. The Mt. Simon/basal sandstone is overlain by interbedded shales and impermeable limestone of the Conasauga Group. The Knox, Rose Run, and St. Peter are overlain by a thick interval of non-porous limestones (Black River or High Bridge Group) and an Upper Ordovician shale interval that is gradational down into the Lexington (Trenton) Limestone. For purpose of this study the Upper Ordovician package is combined with the Lexington formation to form a single confining unit.

Maps and well log cross-sections (**see Appendix ?)** were made from stratigraphic tops (the top elevation of each rock layer) available at the KGS and OGS. Numerous tops were added where missing, and some tops were refined for consistency. For example, the Rose Run Sandstone was limited to the porous sandstone that would serve as an injection target, and does not include sandy dolomite often included with the Rose Run. These maps and cross-sections provide a picture of rock layer thicknesses and depths.

3.3.2.1 St. Peter Sandstone

Figure 4 is an isopach of the St. Peter Sandstone, which is not present at the site. However, to the southeast in Boyd County, the St. Peter is approximately 35 to 100 feet thick and at a depth of approximately 5000 to 5100 feet. To the southwest in Lewis County, the St. Peter is approximately 18 feet thick and at a similar depth.

The St. Peter is considered a deep saline aquifer with regional sequestration potential. To the southeast in the Rome Trough, the St. Peter is much thicker and would be more viable for sequestration than at the site.

3.3.2.2 Knox Group

The total thickness of the Knox Group is shown in **Figure 5**. It ranges in thickness from 800 to 1500 feet. The thickness of the upper Knox Formation, the Beekmantown Dolomite, is shown in **Figure 6**. Near the site, the Upper Knox Dolomite is between 150 and 175 feet thick.

This carbonate sequence produces gas and oil in some areas. The porosity is mainly the **vugular** areas of the dolomite. The KGS is developing tests to determine the porosity and injectivity of the Knox formation in Western Kentucky. In Louisville, the DuPont well used the Knox as the receptacle formation for wastes.

The DuPont well was an injection well used for disposal of waste acids. The waste acid reacted with the carbonate rocks of the Knox formation to produce CO_2. From extensive research on this well, the formation has shown the capacity to store CO_2. From this research, we are able to make assumptions on how the Knox formation will respond in other areas of Kentucky.

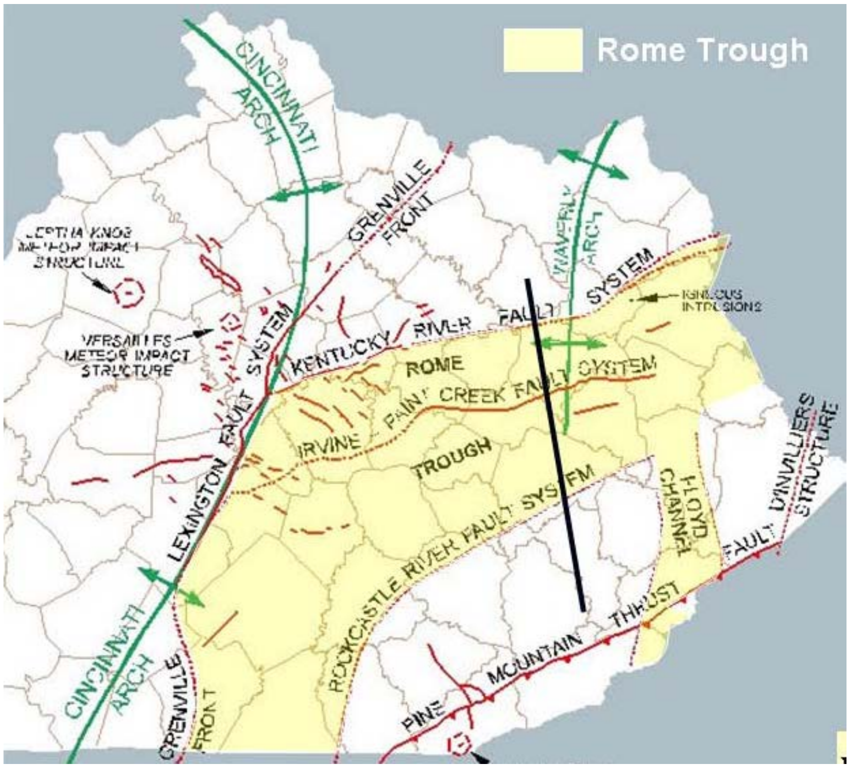
The Rose Run is another regional formation considered a possible sequestration target. The Rose Run is a saline aquifer that separates the lower Copper Ridge Formation from the upper Beekmantown Dolomite. The Rose Run is much thinner in Kentucky than it is in Ohio (**Figure 7**).

The Rose Run sandstone is present at 3674 to 3707 feet below surface in the Newell well. The log indicates sand from 3690 to 3701 feet below surface, which is 11 feet of sandstone. In the southeast region of Boyd County the Rose Run is approximately 1500 feet deep and approximately 100 feet thick. To the southwest in Lewis County, the sandstone is approximately the same thickness as the Newell Well (Type Log), but occurs at 600 feet shallower depth.

3.3.2.3 Mt. Simon / Basal Sandstone

The deepest target formation is the Basal Sand, also identified as the Mt. Simon, which is located above the Precambrian rhyolitic basement rock. It is present in the type log from 5060 to 5128 feet below surface. It is approximately 68 feet thick with approximately 24 feet of porous sandstone according to the well records. The isopach (**Figure 8**) shows two areas of greater thickness to the northeast and southwest.

The Mt. Simon consists of a lower subunit of shale, arkosic sandstone and an upper subunit of relatively shale-free, massive sandstone. The Mt. Simon pinches out at the Rome Trough to the southeast of the site.



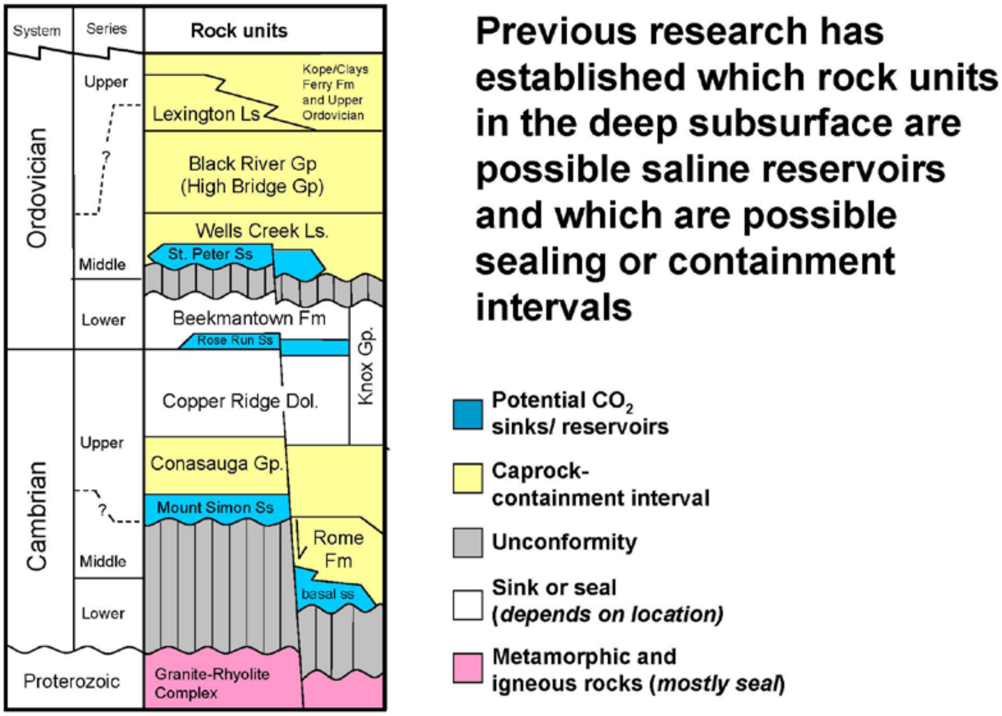
Testing of this sandstone to the west in the Illinois Basin is on-going.   Permeability and porosity are known to vary with depth. The Mt. Simon in the Louisville area has been tested and was too tight to inject wastes in the formation at the DuPont well. Instead, wastes were injected into the Knox dolomites.

3.4 Geologic Sequestration Seals

As part of the sequestration model, each geologic target must have a seal. A geologic seal in this region will be a sedimentary unit that does not have sufficient porosity and permeability to allow carbon dioxide to flow through the seal. The seal will trap the sequestered carbon dioxide.

Geologic traps include: shales, massive limestones and dolomites with little or no secondary porosity and some sandstones where mineralization has in-filled pore spaces. The seals identified in this section are seals for each of the sequestration targets discussed earlier.

Deep rock units in eastern Kentucky



Previous research has established which rock units in the deep subsurface are possible saline reservoirs and which are possible sealing or containment intervals

Source: KYCCS (2008)

3.4.1 Wells Creek Limestone and Black River Group

The type-log shows both the Wells Creek and Black River present above the St. Peter sandstone. They are present at a depth of 2900 – 3508 feet below surface. Both these units are made up of massive limestones (little or no porosity). In the Newell well gas was observed within the Wells Creek at 3382 – 3386 ft and 3472 – 3490 ft below surface. However, this does not seem to indicate the potential for sequestration since this may be local porosity not extending over large areas. The isopach map (**Figure 9**) shows the thickness of the seal increases to the south. Thicknesses range from 500 to almost 1000 feet in the area.

3.4.2 The Conasauga Group, Rome Formation and Tomstown Dolomite

In the Newell well the Tomstown dolomite (4764-5060 feet below surface), Rome Formation (4616 – 4764 feet below surface), and Conasauga Group (4574 – 4616 feet below surface) are all identified. In the generalized column above, these units are shown overlying the Mt. Simon and basal sandstone, and are considered seals for this target. The Tomstown dolomite and Rome Formation are described as clastic carbonates. The Conasauga Group is compiled of alternating shale and limestone formations. In the Newell well, these were not differentiated. The isopach map (**Figure 10**) shows the thickness of this Group increasing to the southeast. The Group ranges in thickness from approximately 500 feet to 1000 feet.

3.5 Geologic Structure

The study area is characterized by a very simple geologic structure. There are no faults that can be interpreted from the structure maps or available seismic data. The structure of the rock units consists of east to slightly southeast dip into the Appalachian Basin, at approximately 70 feet per mile. Two public-domain seismic lines cross part of Greenup County (north-south and east west), but are about 10 miles from the South Shore site. These lines (included) show strong lateral continuity of reflectors, indicating no faults and large scale fractures. This is important for evaluation of sealing units above injection zones.

Structure maps drawn on several geologic horizons show similar structure from the top of the Ordovician down to the Precambrian basement. **Figures 11 – 14** show the following structures*: Top Ordovician, Top Knox Group, Top Copper Ridge Dolomite and Top Precambrian.*

Structural depths range from -2,792 to -8,517 ft (below sea level) for the Precambrian surface. Depths range from -1,129 to -4,774 ft (below sea level) for the top of the Knox Group. Note the top of the Knox Group rises above the 2,500 depth below ground surface (-1,800 ft subsea contour) limit for maintaining a supercritical CO_2 phase west 15.5 miles west (updip) of the site. This means if CO_2 migrates updip, it could change phases, increase in volume and change pressure releases in the system.

The structure maps also indicate that the predicted path of CO_2 migration in a saline aquifer would be to the west-northwest, under the Ohio River toward Ohio. There is no structural or stratigraphic trap present at the site to trap the CO_2 and limit migration. This should not be a negative, as many saline aquifer injection project sites lack a trapping mechanism. Migration of the CO_2 would be a slow process, and solution of CO_2 into the formation fluids over time will decrease the volume of supercritical CO_2 migrating.

Two well log cross sections were constructed near the South Shore site. The location of these sections is shown on the cross section index map (**Figure 15**). The sections have a sea level datum, and show the structural configuration of the correlated units. The leftmost track contains the gamma ray log, while the right track shows the bulk density (RHOB) and neutron porosity (NPHI) logs.

The East-West section (**Figure 16**) shows the uniform east dip into the basin. The North-South section (**Figure 17**) is oriented along strike, showing less structure, except at the northeast end, where dip into the basin increases.

Units from the top of the Ordovician to Precambrian basement are correlated, and shaded in color. Sandstones are shaded yellow, while thick confining zones are shaded green.

Two seismic lines are available for Greenup County and are included in this report. Lines 89-KD-1 (north-south) and 89-KD-2 (east-west) were acquired during investigation of injectate leakage from the Aristech hazardous waste disposal site in Scioto County, Ohio. A map showing the location of these lines is included (**Figure 18**). These lines are migrated, and illustrate the uniform structure and stratigraphy of the county.

3.6 Storage Capacities

In the late 1980's and early 1990's numerous studies were conducted at the Aristech chemical plant site in Scioto County, Ohio, which is about 11 miles from the South Shore site. Since the late 1960's four deep wells have been drilled for waste injection or observation. Concern over nature of leakage of the organic chemical waste from the injection zone (Mt. Simon Sandstone) upward into the Rose Run Sandstone prompted additional data collection and reports. Data from these wells will be invaluable in assessing the CO_2 injection capacity of the Greenup County area. Reports and data from the project are available at the offices of Ohio EPA and the Ohio Geological Survey. OGS sent one of many binders of data from the well, which is included as **Appendix A**. These data include core analyses, brine chemistry, pressure data, core descriptions, and some of the interpretations. KGS will be obtaining the remainder of these documents to aid in ongoing CO_2 sequestration research. **Note: during scanning of the binder numerous missing pages were noted, and KGS will attempt to obtain the missing pages.**

The injection wells were in operation for over 20 years. This site is the best control point for injection data and reservoir parameters for the South Shore property. Some of the data from these appendices was used as input in the CO_2 calculations below.

3.6.1 CO_2 Capacity Calculations

Using data collected in this project, some initial CO_2 storage calculations have been made. The capacity calculations were made using the saline aquifer sequestration calculator at the MidCarb project web site: http://www.midcarb.org/calculators.shtml . The following parameters are required to calculate CO_2 storage capacity:

Reservoir pressure: assumed to be hydrostatic, and calculated at 0.433psi/ft for the reservoir depth

Temperature: taken from well log data in Greenup and Scioto Counties

Formation Fluid salinity: taken from Aristech data in Appendix M (Langmuir, 1991, Table 3). Note the MidCarb calculator has a maximum salinity input of 200,000 ppm. The actual TDS values listed for pre-injection fluids in 1968 samples were 316,000 for the Mt. Simon and 278,000 for the Rose Run, which means that the capacity to store CO_2 will be less than calculated.

Reservoir thickness: thickness of the injection zone, estimated for the South Shore site from nearby wells (Commonwealth Gas #1 Newell well, Greenup Co. and USS Chemicals (Aristech) #1 WDW)

Reservoir area: a unit area of 100 acres was used for these calculations

Reservoir porosity: porosity values were taken from core analyses in the Aristech data; Appendix E. These core porosities closely matched log measured porosity values in the Commonwealth #1 Newell well in Kentucky, so similar values can be predicted at South Shore, which lies structurally between the Aristech site and the Commonwealth Newell well.

3.6.1.1 St. Peter Sandstone zone

The St. Peter Sandstone lies on top of the post-Knox unconformity, and is irregular in its distribution and thickness. In the Newell well, the St. Peter Sandstone is about 21 ft thick, but is absent at the Aristech site. Logs from the Newell well indicate low porosities, less than 5%. Because of the thin and irregular distribution, and low porosity, storage capacity in the St. Peter Sandstone has not been calculated. It may offer limited storage capacity in the area, but will not be a primary injection zone.

3.6.1.2 Knox Dolomite zone

The Knox Group dolomites may have some injection capacity, especially if fractured. Log-derived porosity values from the Commonwealth #1 Newell well in Greenup County show variable porosity values that average 6% over the Knox dolomite intervals (Beekmantown and Copper Ridge). Assuming 10% of the Knox may have favorable porosity values of 8%, a capacity was calculated for a 100 ft zone of 8% porosity. Using appropriate temperature and pressure parameters, this yields a capacity of 24,223 metric tonnes of CO_2 per 100 acres, assuming 100% of the pore space is occupied.

3.6.1.3 Rose Run Sandstone zone

The Rose Run Sandstone is well-developed in the study area and could provide a primary injection zone for CO_2. The Rose Run isopach map shows thicknesses of between 30 and 40 ft across much of Greenup and Carter Counties. A thickness of 37 ft was used for the Rose Run calculation. At an average depth of 4,000 ft near the South Shore site, a pressure of 1700 psi was calculated. A bottom hole temperature value of 100°F was obtained from the Midterra Associates #1 Huber well in Greenup County (permit 20187) at the top of the Copper Ridge. Core data from the Aristech site is consistent with log data from Kentucky, with a consistent 10% porosity in the main sandstone portion. These parameters yield a storage capacity of 11,138 metric tonnes per 100 acres assuming 100% of the pore space is occupied.

3.6.1.4 Mt. Simon Sandstone/basal sandstone zone

The Mt. Simon Sandstone and equivalent basal sandstone directly overlie Precambrian igneous and metamorphic rocks in the study area. This interval is arkosic in most wells in the area, giving a high gamma ray response on logs (similar to shales). Cores from the Aristech site and low resistivity values indicate this interval is porous sandstone, with potassium feldspars affecting the gamma log response. The thickness of the Mt. Simon varies across the area, but it is the thickest potential injection interval at the South Shore site. It is 116 ft thick in the Commonwealth #1 Newell well, about 10 miles from South Shore, and 114 ft thick in a well in Jackson Co., Ohio. At Aristech, where there are core data, the Mt. Simon is 73 ft thick, and averages 12% porosity. A 25 ft interval in the Aristech Mt. Simon core ranges from 10 to 15% porosity. A thickness of 100 ft was assumed for the Mt

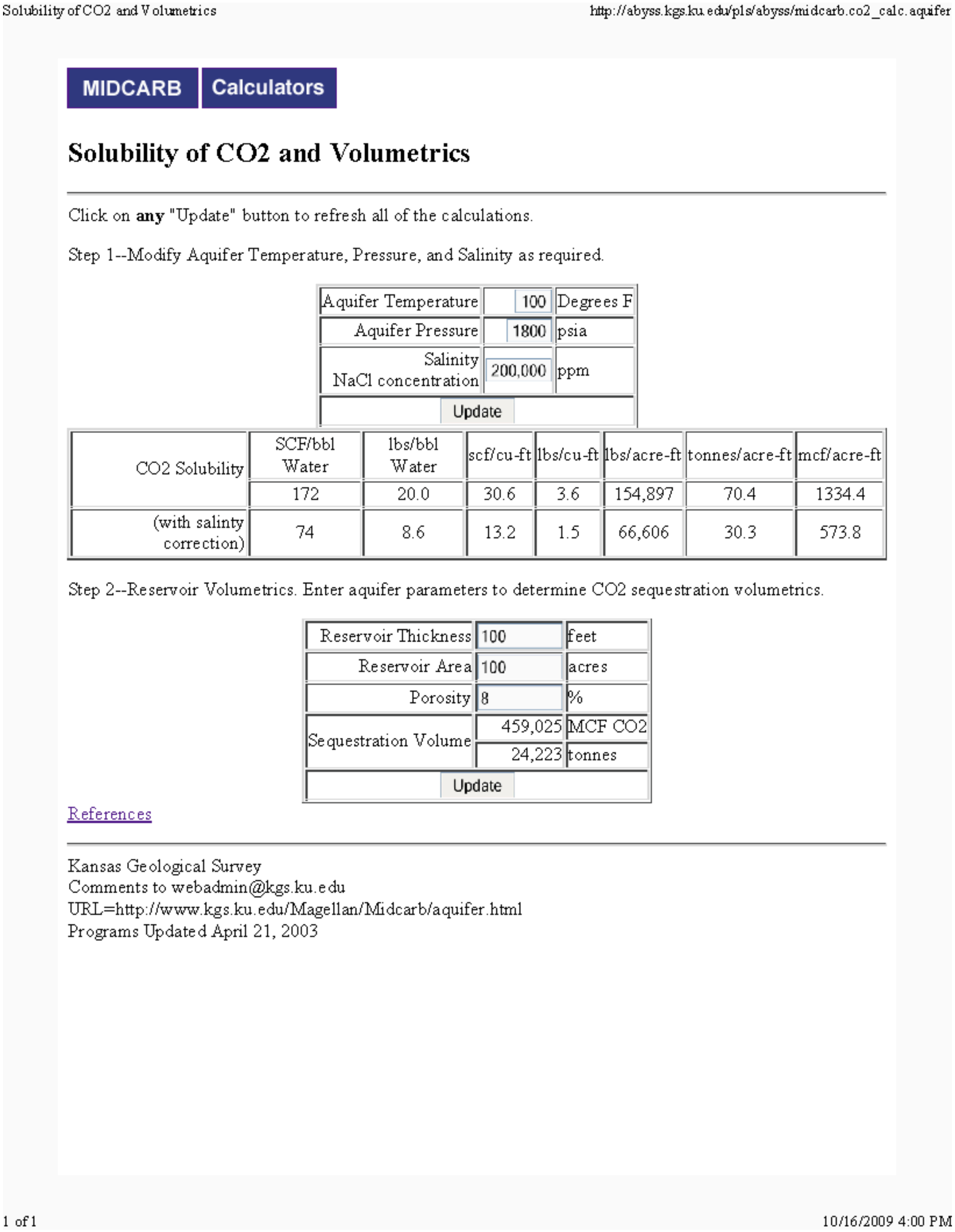
Simon in the calculation. A depth of 5,300 ft was used, giving a reservoir pressure of 2300 psi. A higher temperature of 110°F was used for the deeper Mt. Simon. These parameters yield a CO_2 storage capacity of 36,757 metric tonnes for the Mt. Simon/basal sandstone zone, assuming 100% of the pore space is occupied in a 100 acre area and 100 ft thickness of rock.

The reservoir parameters used and CO_2 capacities calculated are shown in the table below:

Zone	Temperature (degrees F)	Pressure (psi)	Salinity (ppm)	Thick-ness (ft)	Area (acres)	Porosity (percent)	CO_2 Volume (tonnes)
Knox dolomite	100	1800	200,000	100	100	8	24,223
Rose Run	100	1700	200,000	37	100	10	11,138
Mt. Simon Ss	110	2300	200,000	100	100	12	36,757

The 10,000 BPD facility at South Shore will produce approximately 8.2 thousand tonnes per day CO_2 emissions. That means the facility would use up 100 acres of the Knox formation every 3 days, and 100 acres of the Rose Run in just over a day, and 100 acres of Mt. Simon every 4 days.

Knox Carbonate CO_2 Capacity Calculation



Solubility of CO2 and Volumetrics

Click on **any** "Update" button to refresh all of the calculations.

Step 1--Modify Aquifer Temperature, Pressure, and Salinity as required.

Aquifer Temperature	100	Degrees F
Aquifer Pressure	1800	psia
Salinity NaCl concentration	200,000	ppm

CO2 Solubility	SCF/bbl Water	lbs/bbl Water	scf/cu-ft	lbs/cu-ft	lbs/acre-ft	tonnes/acre-ft	mcf/acre-ft
	172	20.0	30.6	3.6	154,897	70.4	1334.4
(with salinity correction)	74	8.6	13.2	1.5	66,606	30.3	573.8

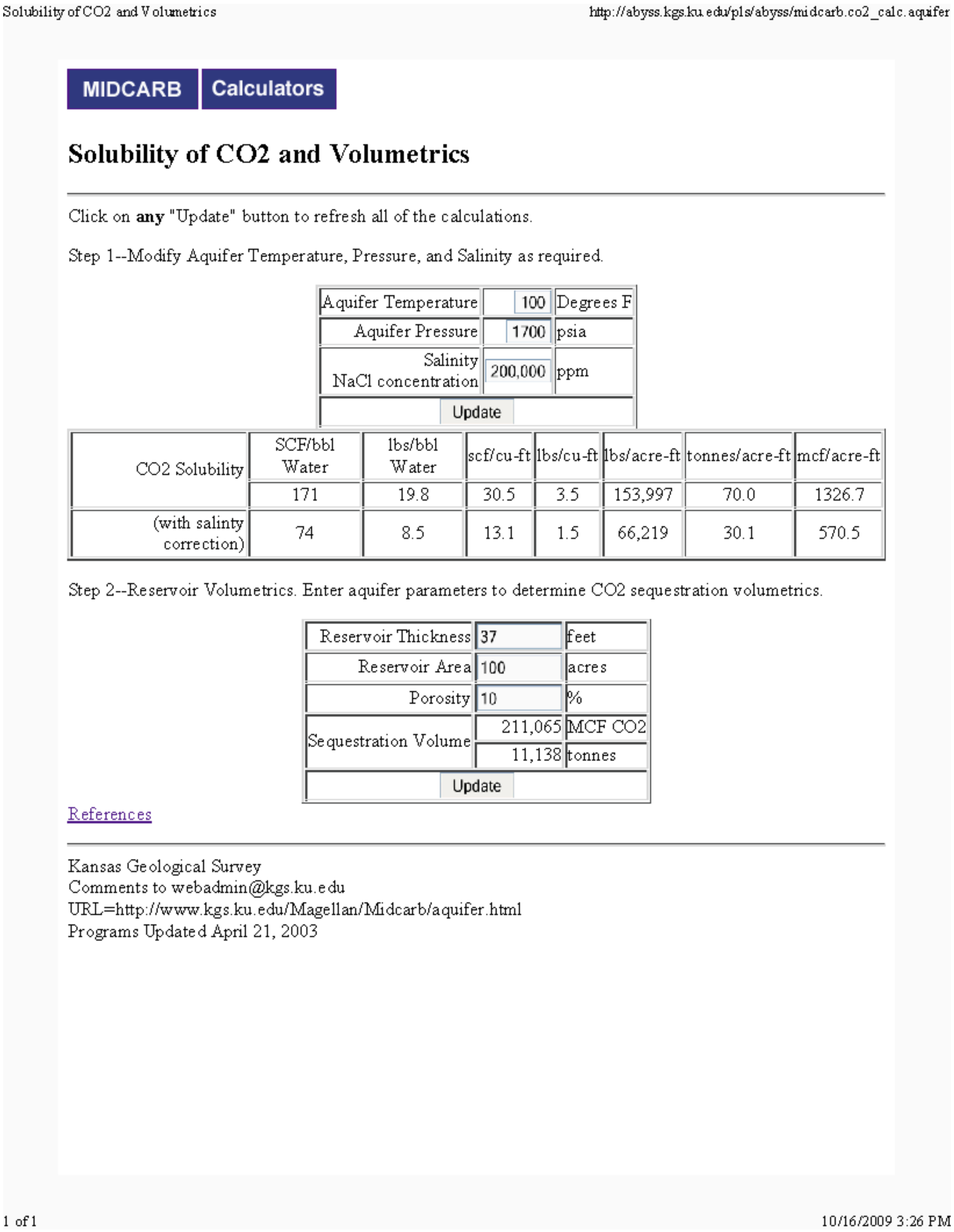
Step 2--Reservoir Volumetrics. Enter aquifer parameters to determine CO2 sequestration volumetrics.

Reservoir Thickness	100	feet
Reservoir Area	100	acres
Porosity	8	%
Sequestration Volume	459,025	MCF CO2
	24,223	tonnes

References

Kansas Geological Survey
Comments to webadmin@kgs.ku.edu
URL=http://www.kgs.ku.edu/Magellan/Midcarb/aquifer.html
Programs Updated April 21, 2003

Rose Run CO_2 Capacity Calculation



Solubility of CO2 and Volumetrics

Click on **any** "Update" button to refresh all of the calculations.

Step 1--Modify Aquifer Temperature, Pressure, and Salinity as required.

Aquifer Temperature	100	Degrees F
Aquifer Pressure	1700	psia
Salinity NaCl concentration	200,000	ppm

CO2 Solubility	SCF/bbl Water	lbs/bbl Water	scf/cu-ft	lbs/cu-ft	lbs/acre-ft	tonnes/acre-ft	mcf/acre-ft
	171	19.8	30.5	3.5	153,997	70.0	1326.7
(with salinty correction)	74	8.5	13.1	1.5	66,219	30.1	570.5

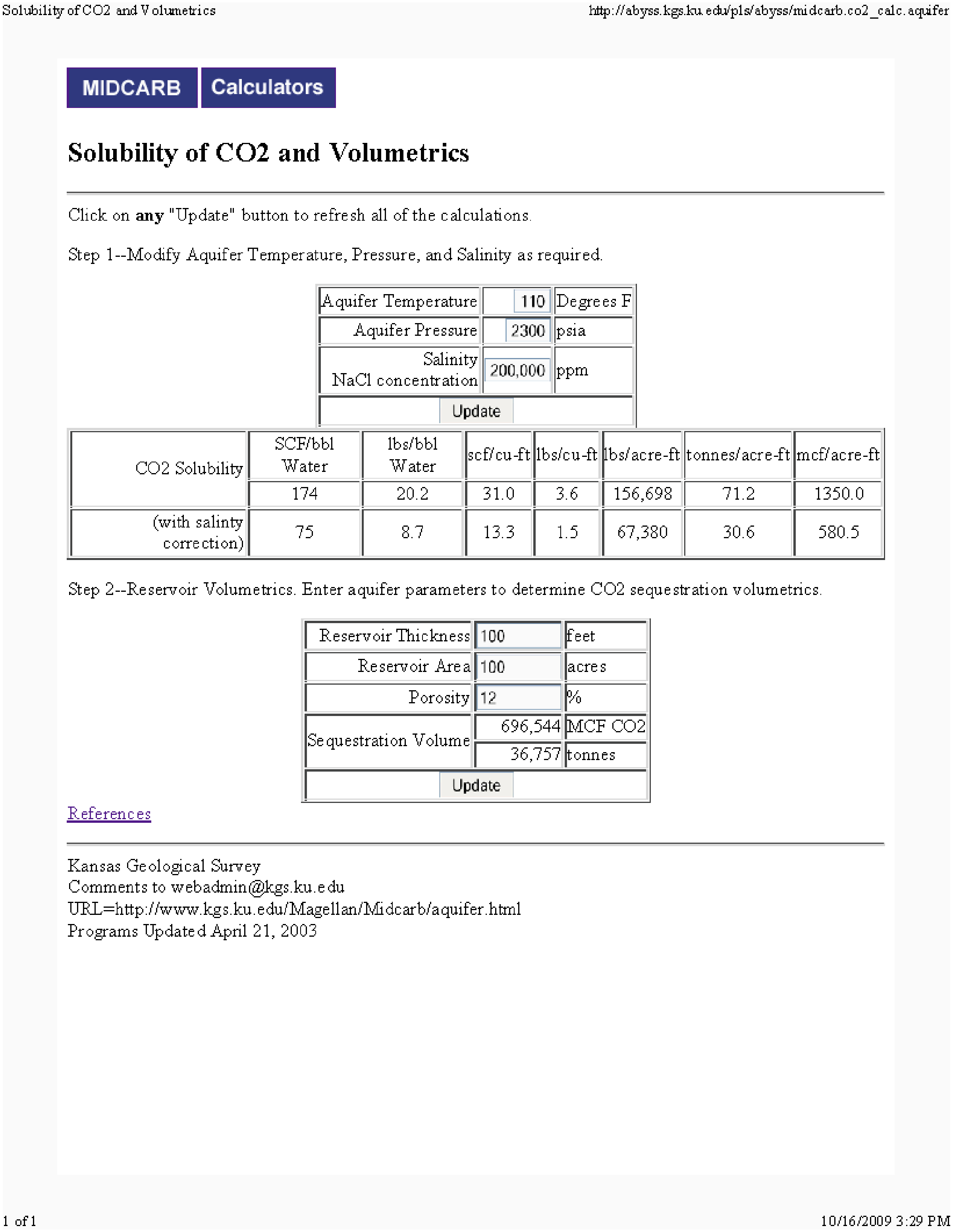
Step 2--Reservoir Volumetrics. Enter aquifer parameters to determine CO2 sequestration volumetrics.

Reservoir Thickness	37	feet
Reservoir Area	100	acres
Porosity	10	%
Sequestration Volume	211,065	MCF CO2
	11,138	tonnes

References

Kansas Geological Survey
Comments to webadmin@kgs.ku.edu
URL=http://www.kgs.ku.edu/Magellan/Midcarb/aquifer.html
Programs Updated April 21, 2003

Mt. Simon CO_2 Capacity Calculation



Solubility of CO2 and Volumetrics http://abyss.kgs.ku.edu/pls/abyss/midcarb.co2_calc.aquifer

Solubility of CO2 and Volumetrics

Click on **any** "Update" button to refresh all of the calculations.

Step 1--Modify Aquifer Temperature, Pressure, and Salinity as required.

Aquifer Temperature	110	Degrees F
Aquifer Pressure	2300	psia
Salinity NaCl concentration	200,000	ppm
Update		

CO2 Solubility	SCF/bbl Water	lbs/bbl Water	scf/cu-ft	lbs/cu-ft	lbs/acre-ft	tonnes/acre-ft	mcf/acre-ft
	174	20.2	31.0	3.6	156,698	71.2	1350.0
(with salinty correction)	75	8.7	13.3	1.5	67,380	30.6	580.5

Step 2--Reservoir Volumetrics. Enter aquifer parameters to determine CO2 sequestration volumetrics.

Reservoir Thickness	100	feet
Reservoir Area	100	acres
Porosity	12	%
Sequestration Volume	696,544	MCF CO2
	36,757	tonnes
Update		

References

Kansas Geological Survey
Comments to webadmin@kgs.ku.edu
URL=http://www.kgs.ku.edu/Magellan/Midcarb/aquifer.html
Programs Updated April 21, 2003

1 of 1 10/16/2009 3:29 PM

3.6.2 Efficiency of CO_2 Storage

The capacities calculated above assume 100% of the rock's pore volume will be occupied by carbon dioxide. This is an ideal situation that is never achieved due to fluid characteristics and geologic variability within the reservoir. Frailey (2008) has defined an efficiency factor for carbon storage that takes into account a number of factors that reduce the calculated volume of CO_2 that can be stored in a geologic reservoir[9]. Frailey's efficiency factor takes into account the following parameters:

- Net to total area of a basin suitable for sequestration
- Net to gross thickness of a reservoir that meets minimum porosity and permeability requirements
- Ratio of effective to total porosity (fraction of connected pores)
- Areal displacement efficiency- area around a well that can be contacted by CO_2
- Vertical displacement efficiency- fraction of vertical thickness that will be contacted by CO_2
- Gravity- fraction of reservoir not contacted by CO_2 due to buoyancy effects
- Displacement efficiency- portion of pore volume that can be filled by CO_2 due to irreducible water saturation

Combining these factors using a Monte Carlo simulation results in a range of efficiency values of 0.01 to 0.04 (1% to 4%), with a confidence range of 15 to 85 percent. The gross storage volumes listed previously should be realistically reduced by an efficiency factor. 4% is used below to reduce the capacities above to more likely volumes.

---

[9] Frailey, Scott, 2008, Appendix 4, Carbon Sequestration Atlas of the United States and Canada, Second Edition, National Energy Technology Laboratory, U.S. Department of Energy, 140 p.

Zone	Thickness (ft)	Area (acres)	Porosity (percent)	CO_2 Volume (tonnes)	Efficiency factor for volume	Adjusted CO_2 Volume (tonnes)
Knox dolomite	100	100	8	24,223	4%	969
Rose Run	37	100	10	11,138	4%	446
Mt. Simon Ss	100	100	12	36,757	4%	1,470

The application of an efficiency factor significantly reduces the storage capacities. For example, Greenup County is 896 square kilometers or 221,406 acres in area. Using the adjusted capacities above, The Mt. Simon Sandstone in Greenup County could reasonably store 3,254,668 tonnes of carbon dioxide, or approximately 1 year's emissions from the 10,000 BPD facility. The combination of all 3 storage zones yields a corrected capacity of 6,387,563 tonnes for all of Greenup County, or 2 year's emissions from the 10,000 BPD facility. Similar calculations can be performed for the other counties in the area. But it is obvious that a gasification plant that produces about 3 million tonnes of carbon dioxide per year would quickly fill the available pore space in nearby counties.

CHAPTER 4: CONCLUSIONS

A coal gasification plant in Vresová, Czech Republic. Taken from https:/.../zero_emission_power_plants.htm

4.1 Capture and Sequestration for South Shore

The capture and storage of carbon dioxide is driven by the desire to reduce greenhouse gases in the United States. Current research into the viability of carbon storage in geologic formations continues on both a state and national level. As more information about the subsurface becomes available, a more informed decision can be made concerning long-term storage.

Current Capture Technology is limited to acid gas removal using chemical solvents, such as amines, and physical solvents. Commercial scale carbon dioxide capture has not been deployed, but is in the works. The technology has been and is being used to remove smaller amounts of carbon dioxide in the natural gas industry. R&D for new capture technology is being funded in the US, Canada, and Europe. Pilot scale tests are being performed now, but commercialization may be several years off.

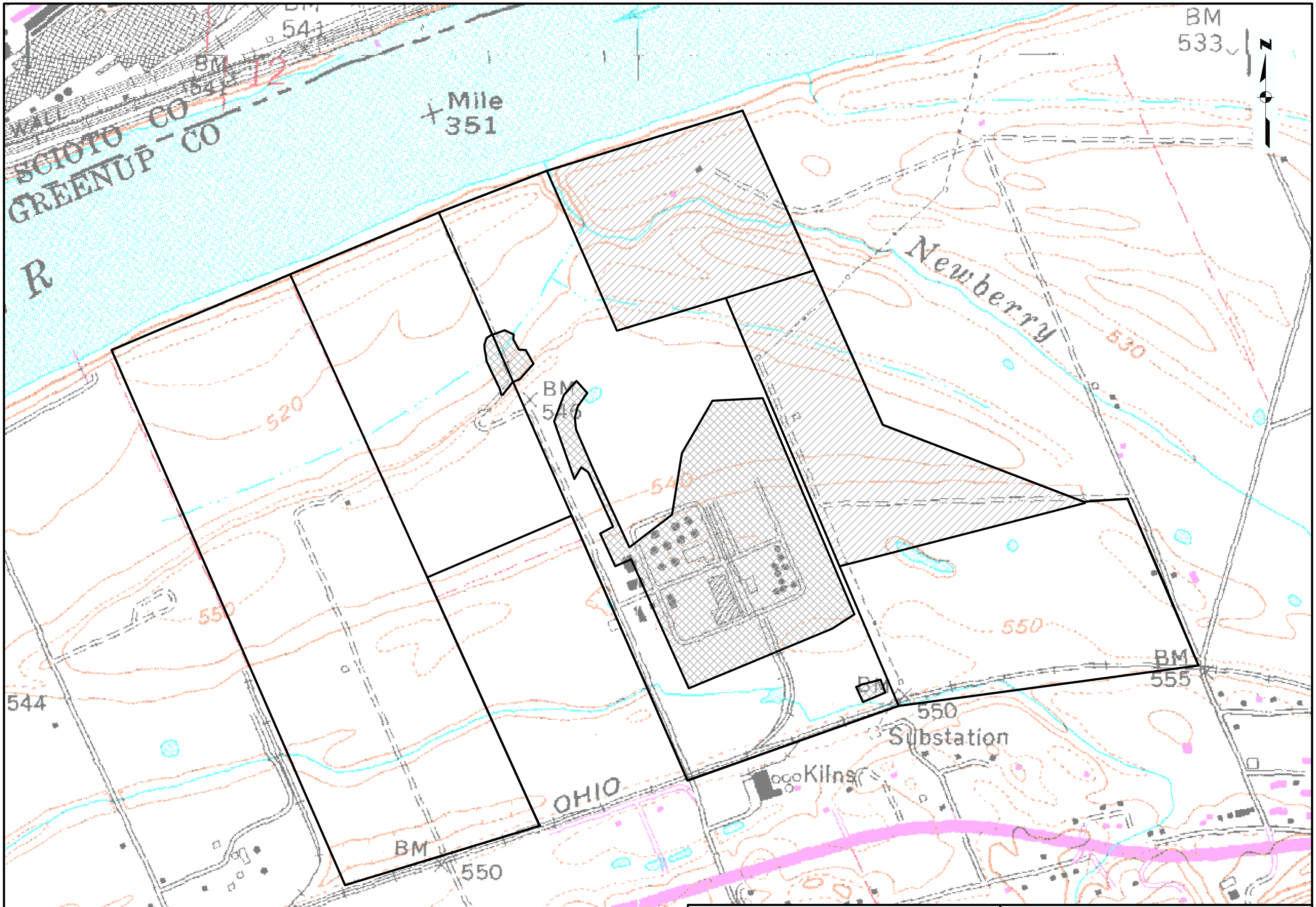
Carbon dioxide is currently being transported by pipeline for EOR projects, and new pipelines are being planned. However, pipelines have not been built for transportation in the storage of carbon dioxide from power plants or CTL plants. The total amount of carbon dioxide transported is much greater than for EOR projects. Researchers in the US, Europe, and Canada are looking at design parameters and providing new construction and maintenance guidelines. The total costs of transportation have not resolved because of uncertainties in the construction costs.

The targets and seals have been discussed for each of these scenarios. As stated earlier, information available on deep formations is limited to a few wells, seismic data, and interpretation of known areas. As such, this is a preliminary comparison and the addition of future work should be incorporated.

For the South Shore project, carbon storage will most likely be to the south and east of the site. On-site deep sequestration is the least viable option at the moment given the storage capacities shown in this report. It should be noted that sequestration whether in deep aquifers or part of an EOR/EGR project will require multiple wells over the reservoir area. One injection well will not be sufficient over large areas.

Future work for sequestration for this facility should include discussions with the state geological surveys and wells owners for EGR and EOR projects in the larger fields. Identification of actual markets is crucial. Research on carbon dioxide flooding for these fields will also need to be completed.

As KGS develops a better understanding of the sequestration potential in eastern Kentucky, a location for an injection field would need to be determined and additional testing would need to be done.



LEGEND

▩ NO CAP INTERFERENCE/NO DOMESTIC GROUNDWATER USE

▨ NO DOMESTIC GROUNDWATER USE

NOTE:
NO PULLING GROUNDWATER WITHOUT APPROVAL

FIGURE 1 - SITE LOCATION
SOUTH SHORE
GREENUP COUNTY, KENTUCKY
SOUTHER QUADRANGLE: PORTSMOUTH, KY-OH - 1968
NORTHERN QUADRANGLE: NEW BOSTON - 1961
(BOTH PHOTOREVISED - 1975)
SCALE: 1"=1000'

FIGURE 2

OIL AND GAS POOL MAP

South Shore Oil and Gas Field Index Map

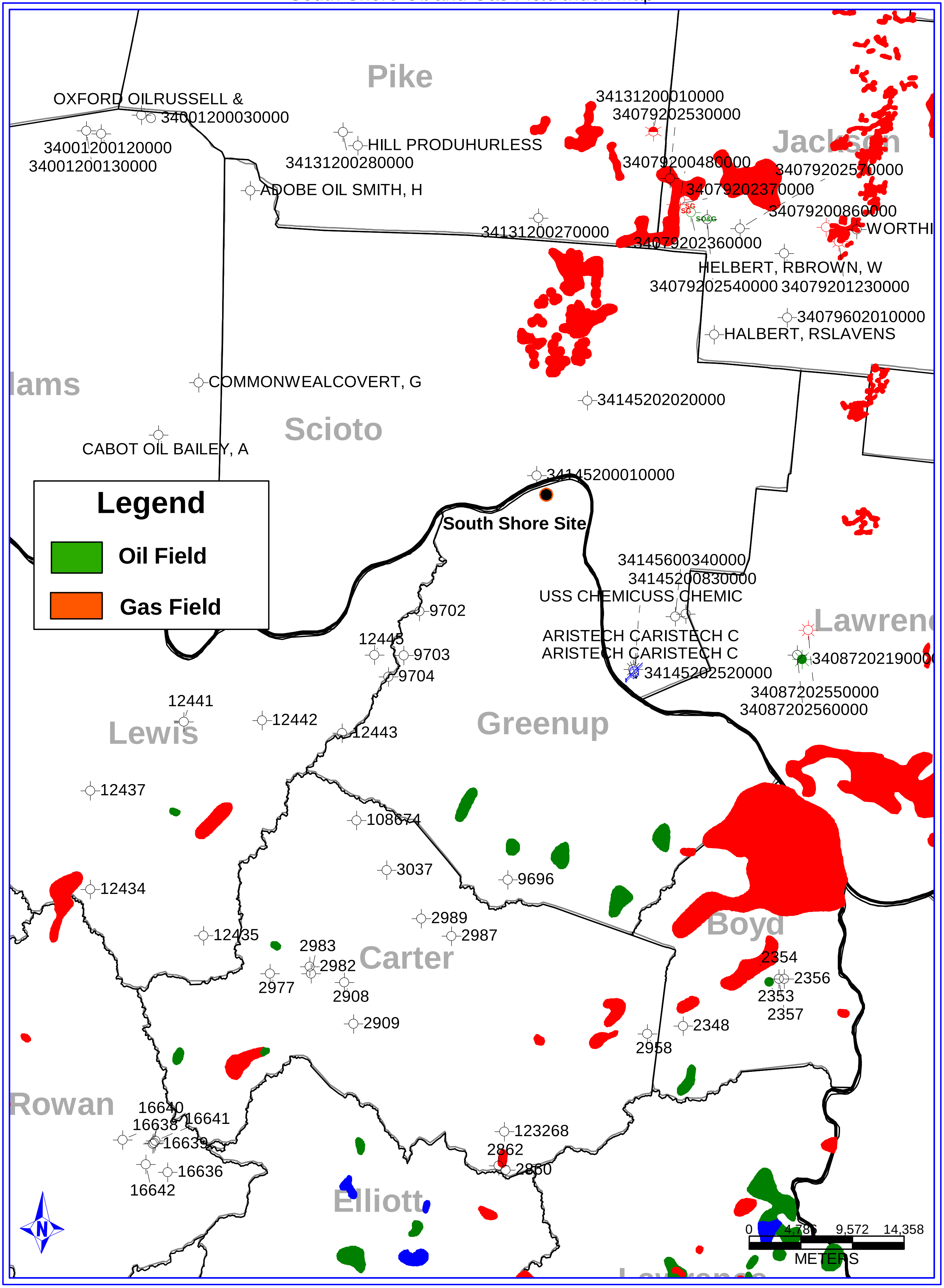


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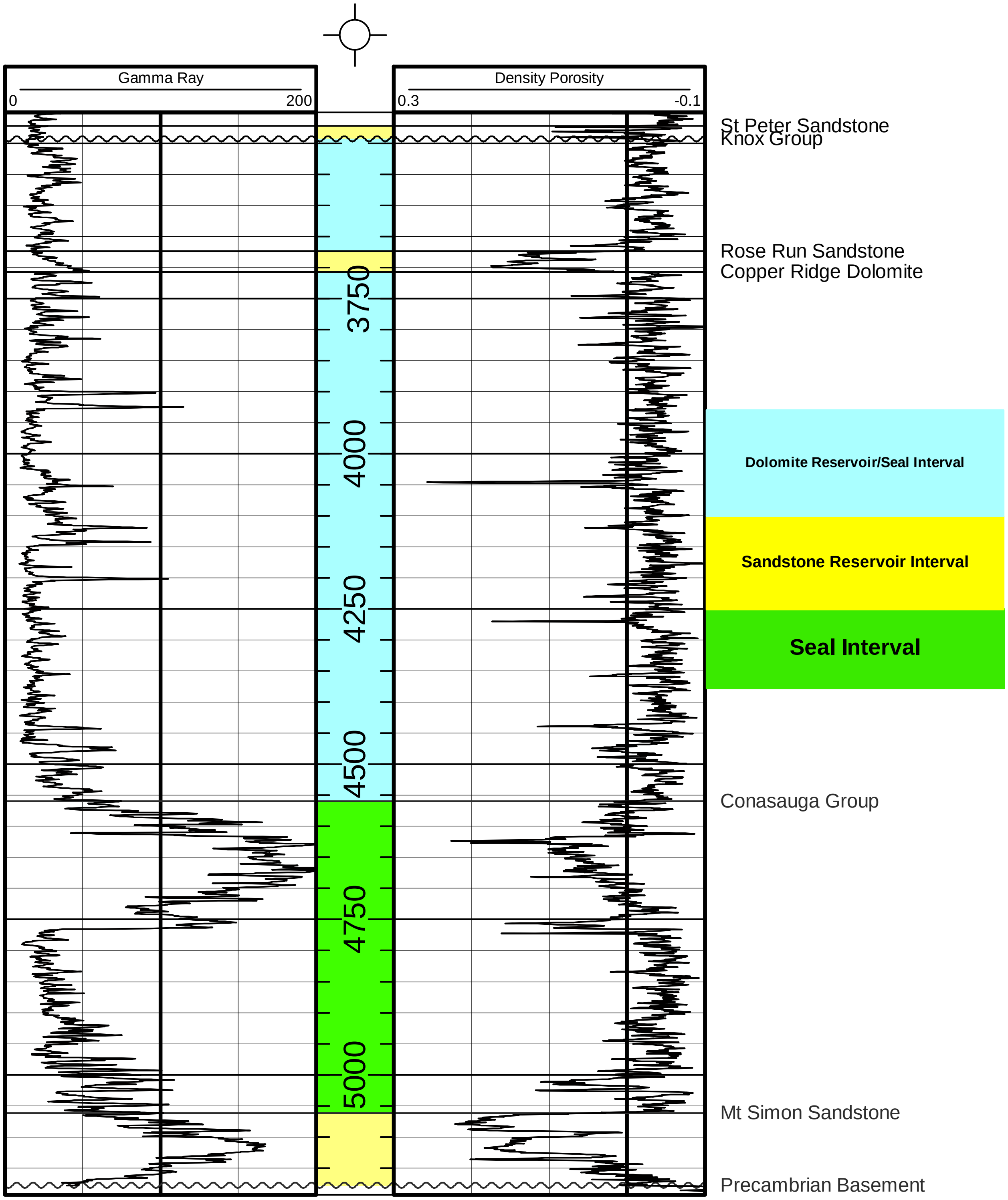
FIGURE 3

GREENUP TYPE LOG - CLOSE UP

Type Geophysical Log for Greenup County



16089001580000
COMMONWEALTH GAS CORP
1
NEWELL, D P
GREENUP
KY

HS=1

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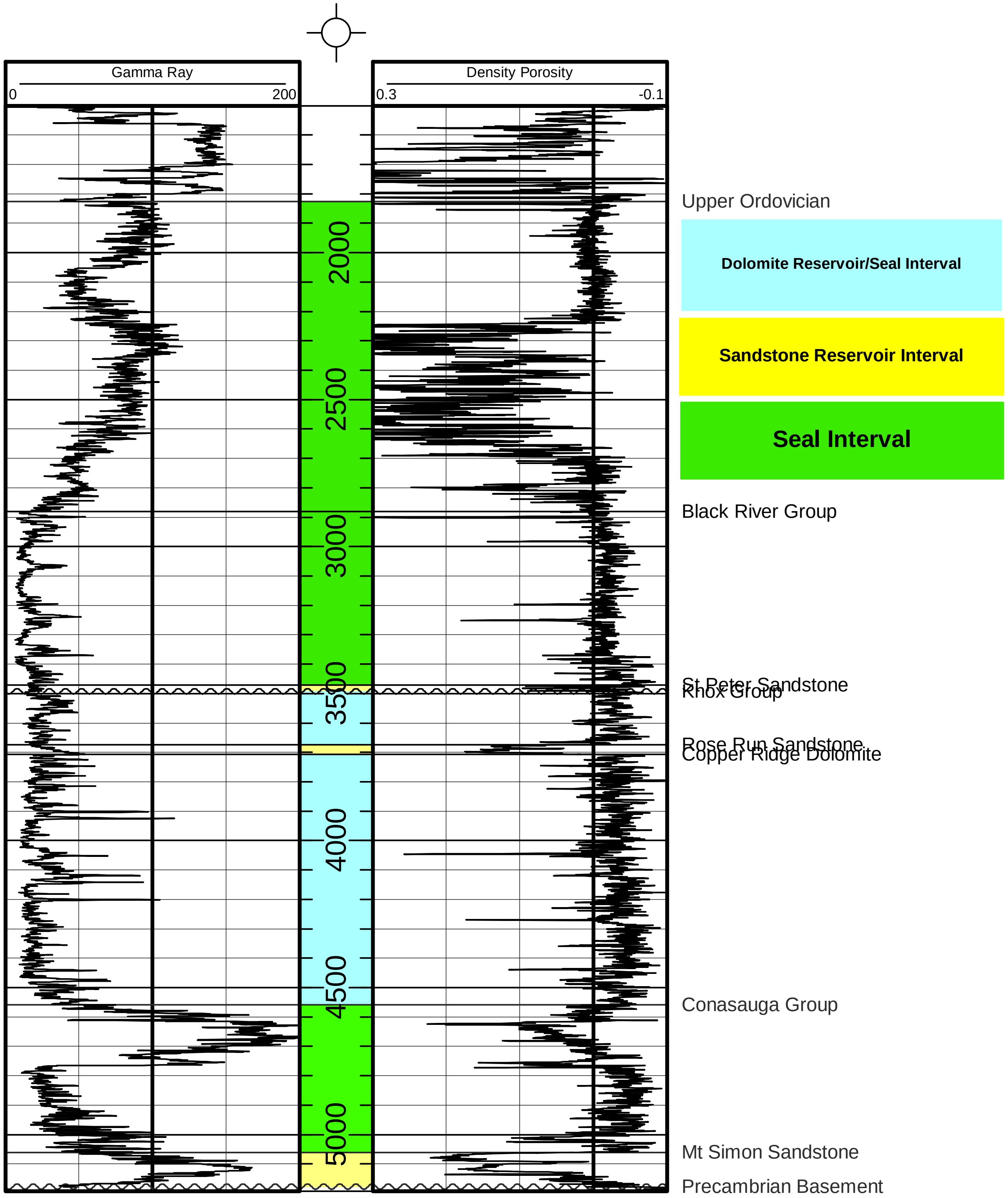
FIGURE 3B

GREENUP TYPE LOG

Type Geophysical Log for Greenup County



16089001580000

COMMONWEALTH GAS CORP

1

NEWELL, D P

GREENUP

KY

HS=1

PETRA 10/12/2009 11:55:12 AM (Type_Log_Greenup.CST)

FIGURE 4

ST. PETER SANDSTONE ISOPACH

St. Peter Sandstone Thickness (ft) (reservoir interval)

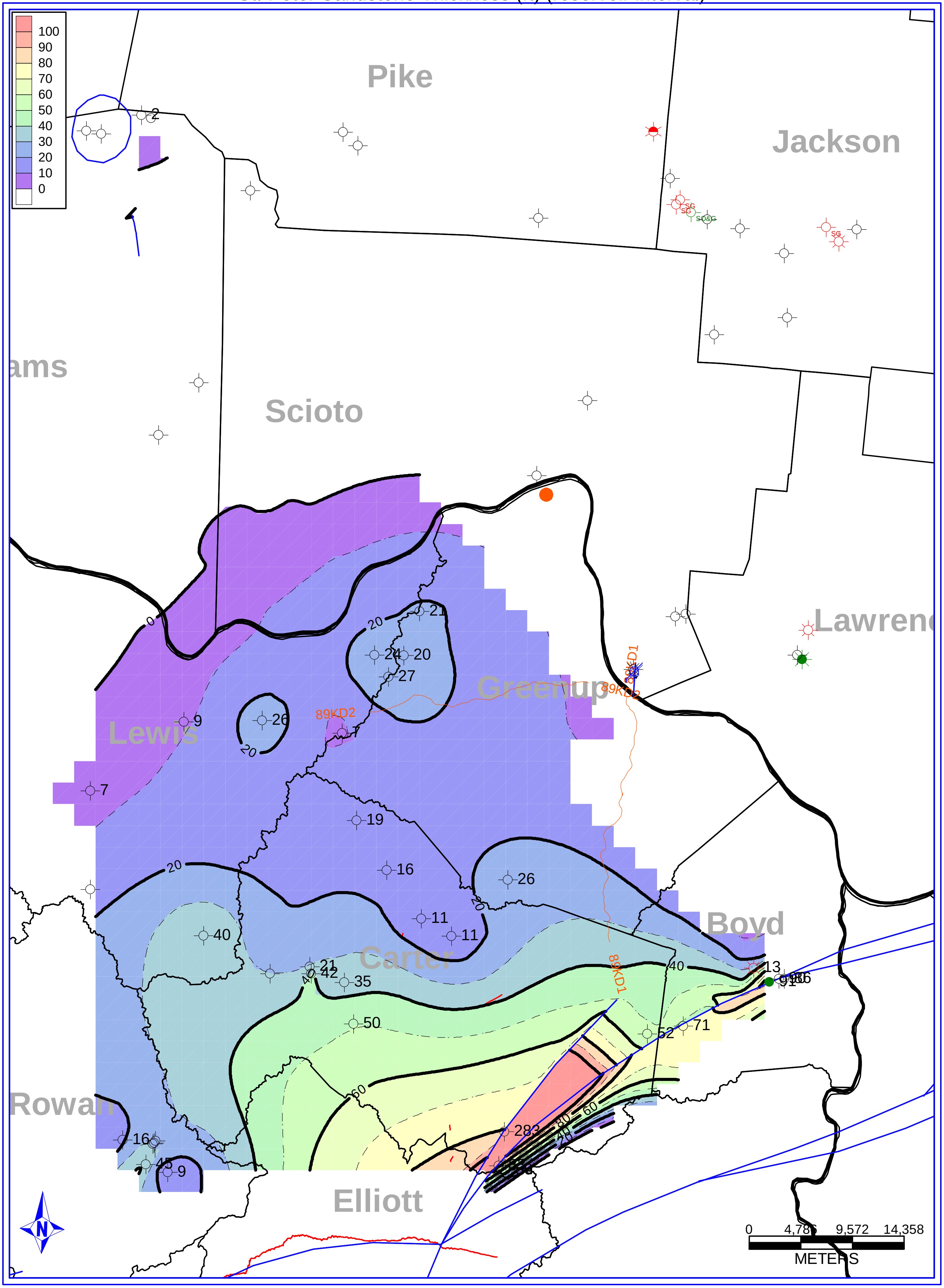


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FIGURE 5

KNOX FORMATION ISOPACH

Knox Group Thickness (ft) (reservoir and seal interval)

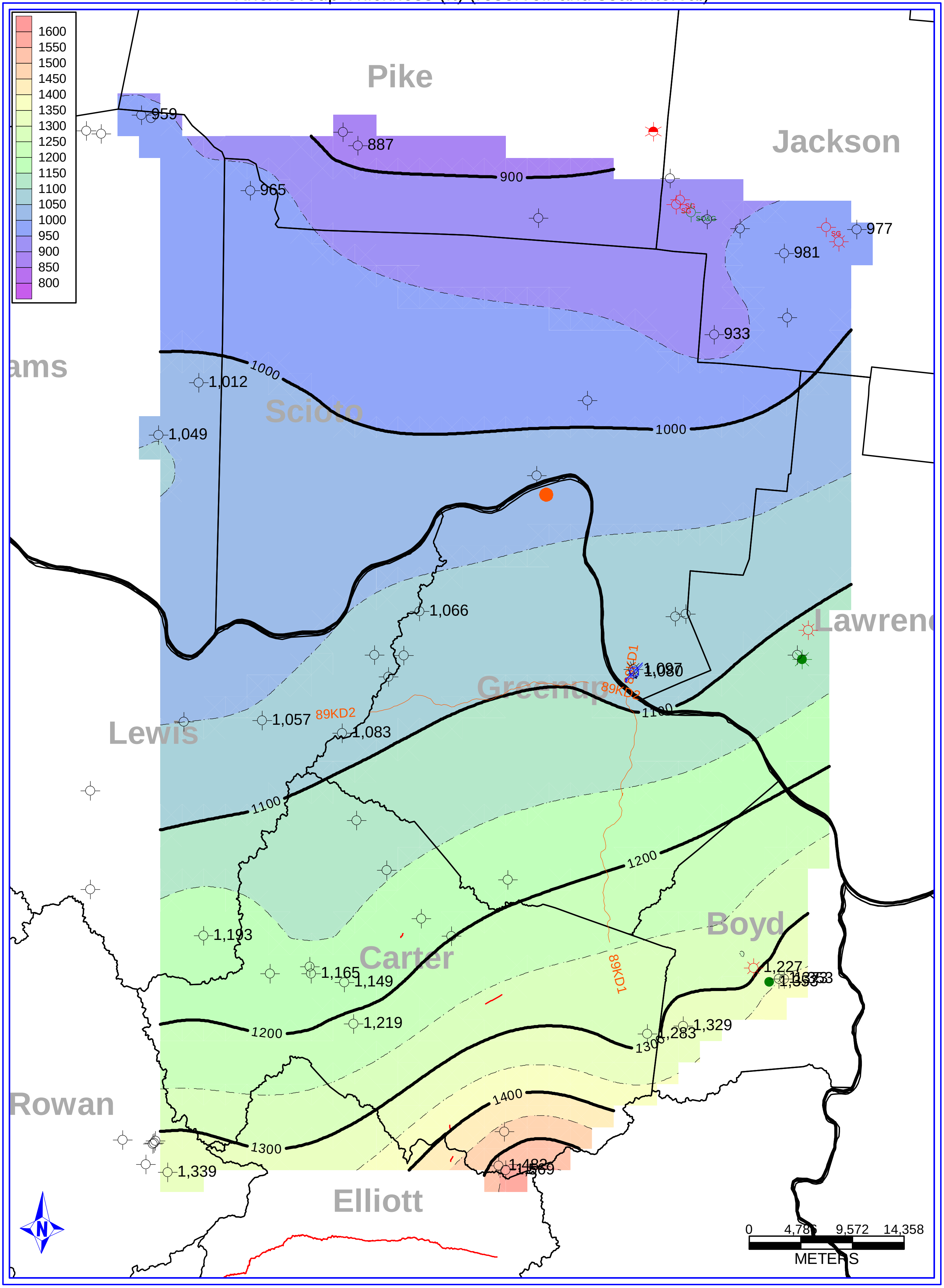

FIGURE 6

BEEKMANTOWN ISOPACH

Beekmantown (Upper Knox) Thickness (ft) (seal and reservoir)

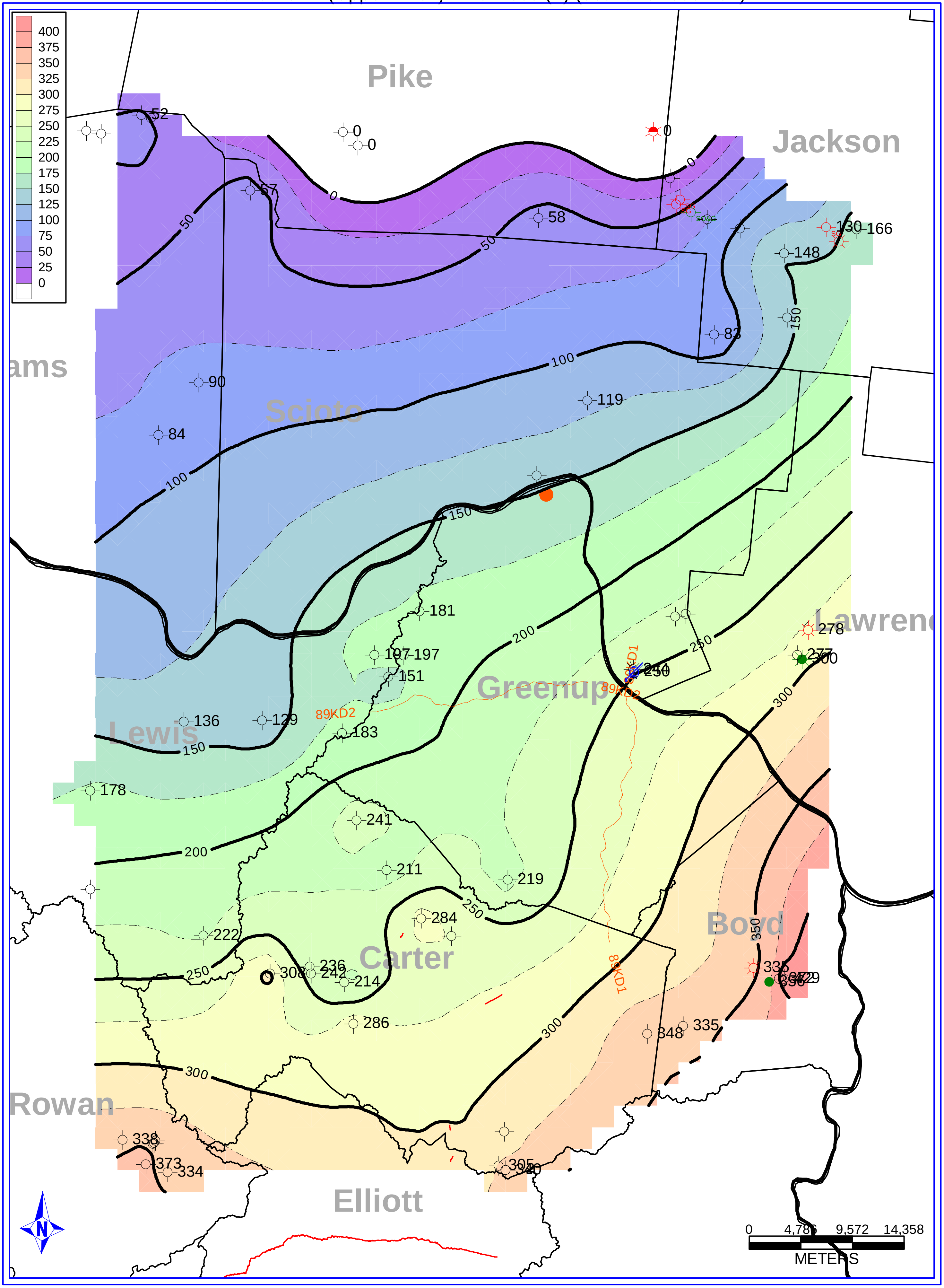

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FIGURE 7

ROSE RUN SANDSTONE ISOPACH

Rose Run Sandstone Thickness (ft) (reservoir)

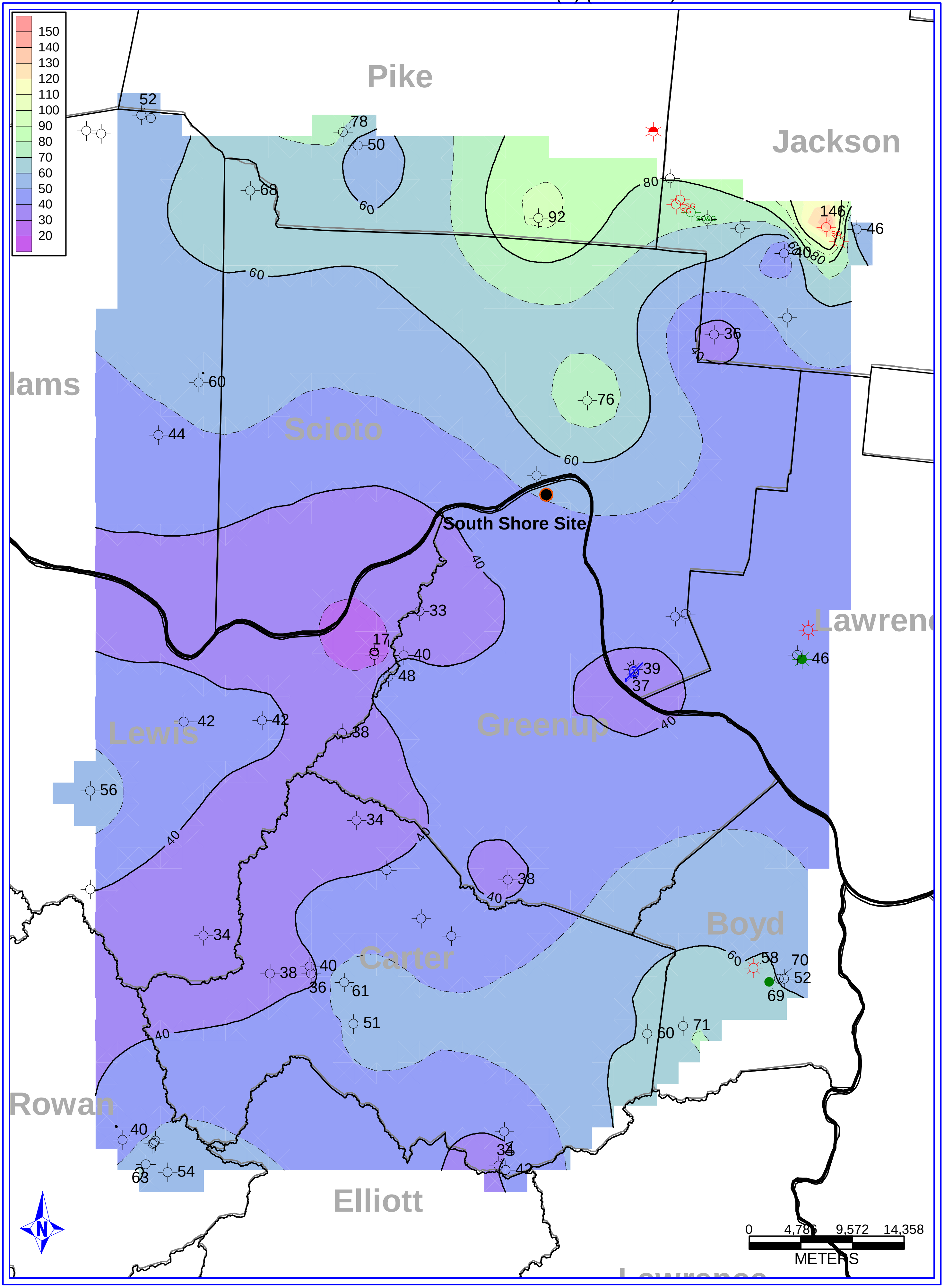

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FIGURE 8

MT. SIMON – BASAL SANDSTONE ISOPACH

Mt. Simon Ss/Basal Ss Thickness (ft) (reservoir interval)

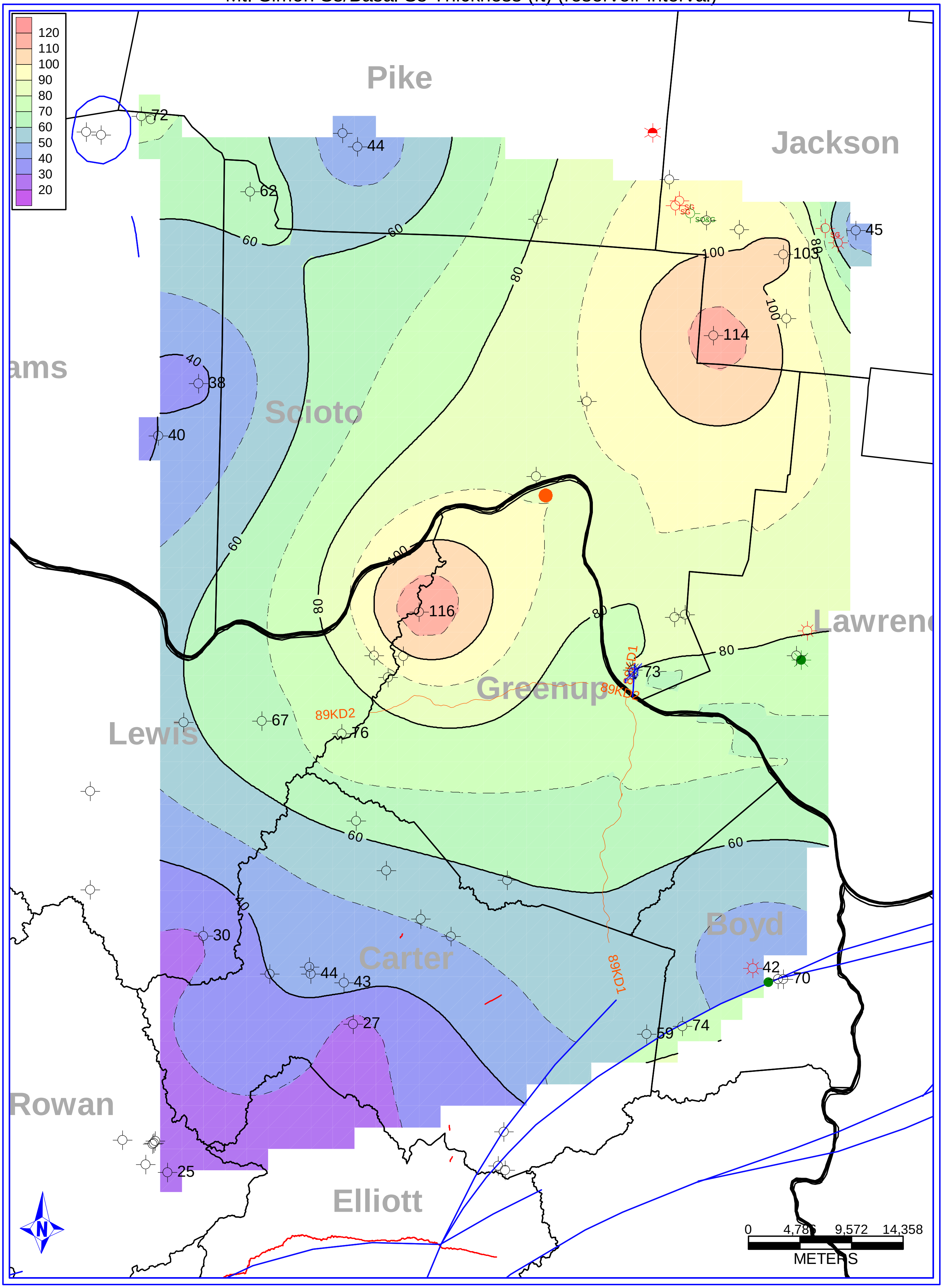

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FIGURE 9

BLACK RIVER ISOPACH

Black River Group Thickness (ft) (seal interval)

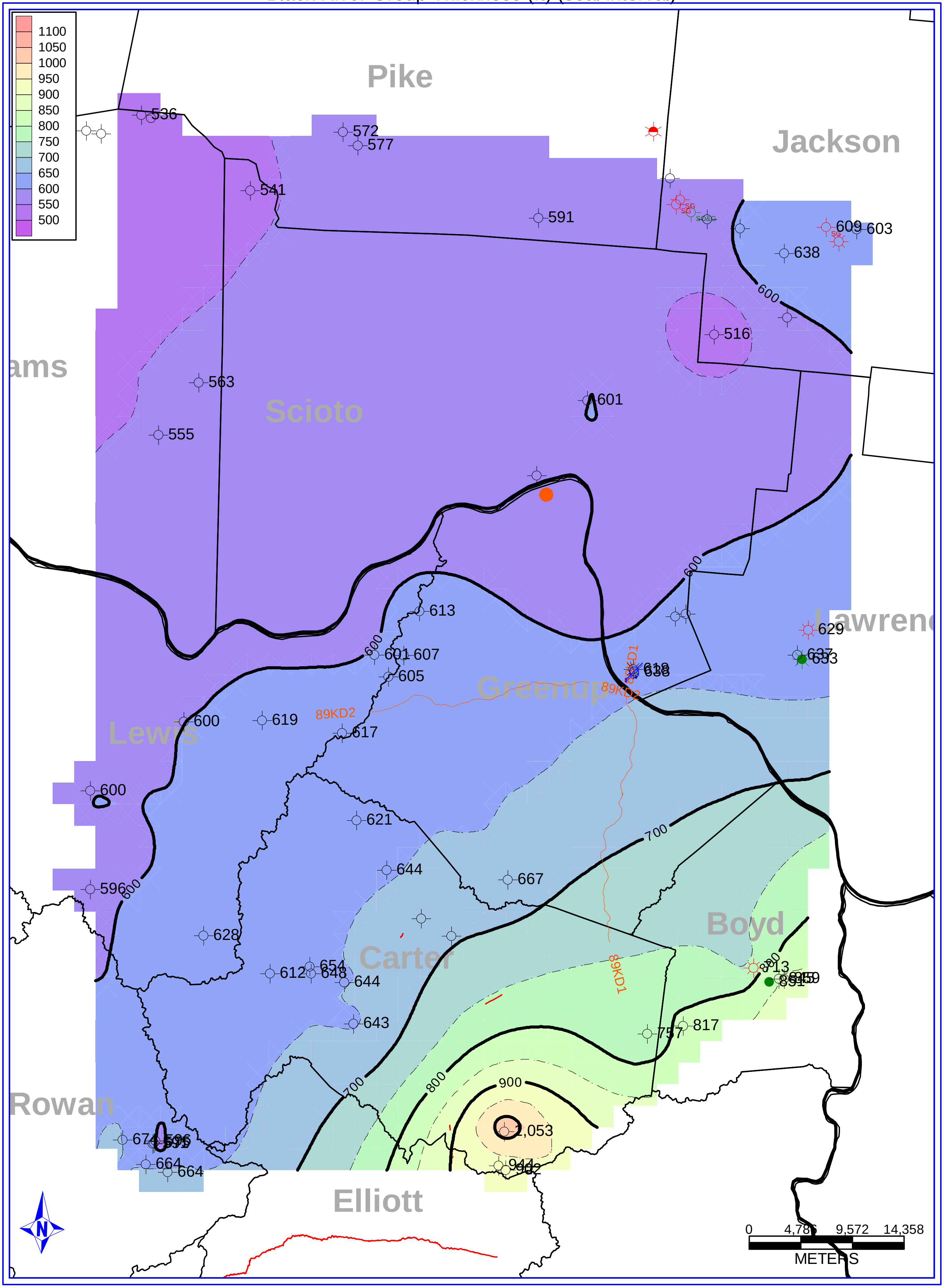

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FIGURE 10

CONASAUGA ISOPACH

Conasauga Group Thickness (ft) (seal interval)

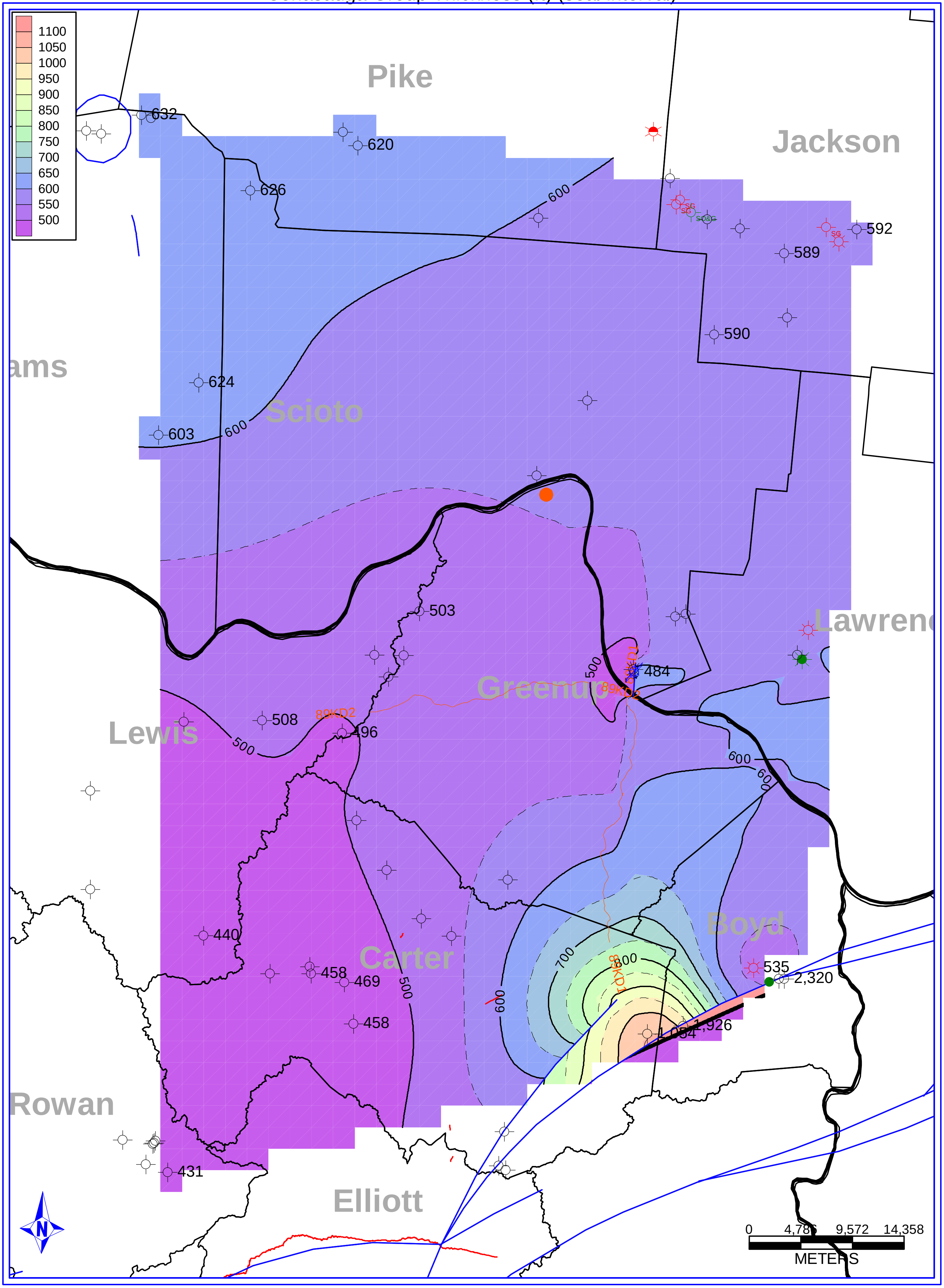

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FIGURE 11

TOP OF ORDOVICIAN STRUCTURE

Top Ordovician Structure Map (sea level datum)

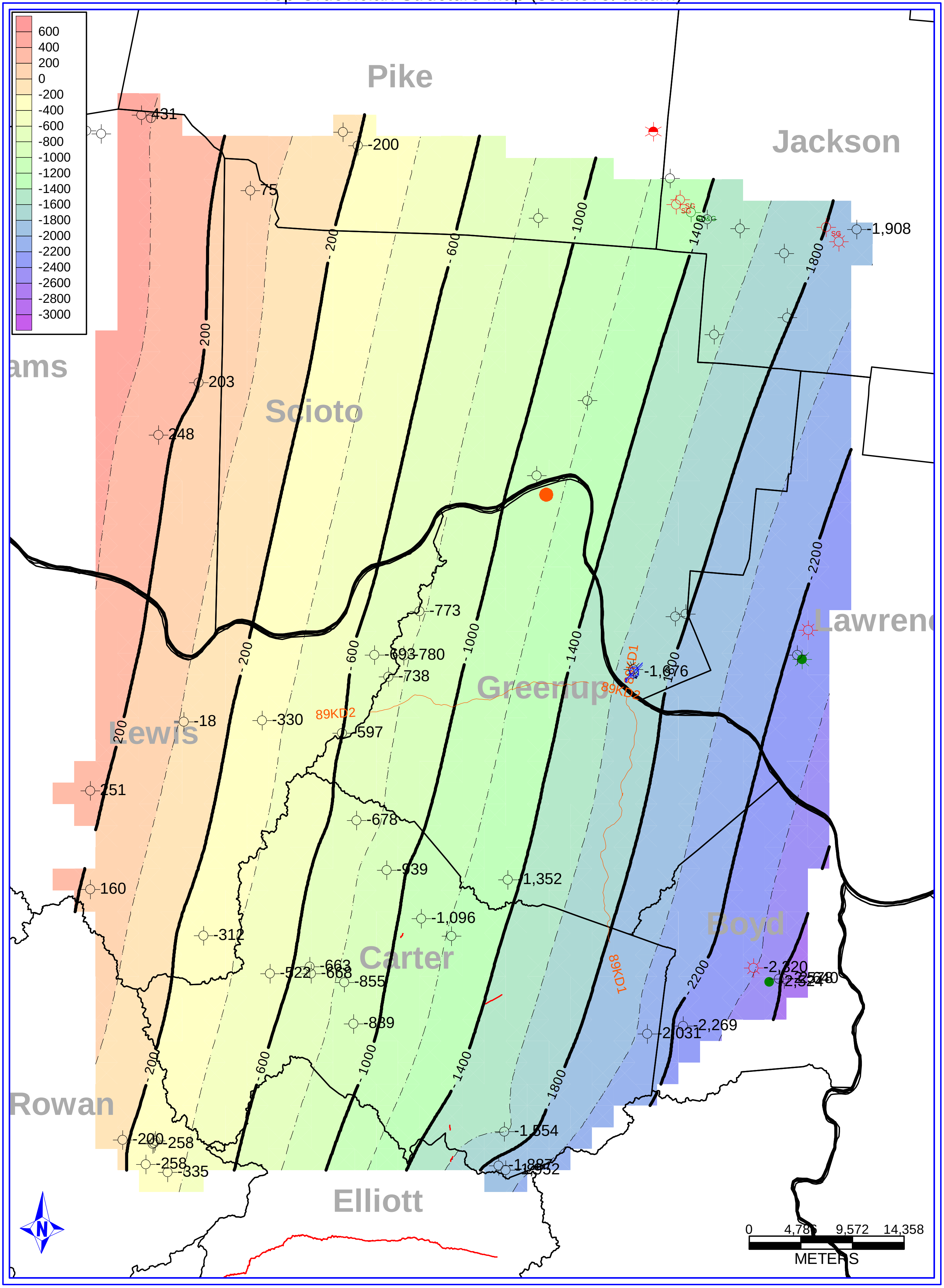

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FIGURE 12

TOP OF KNOX STRUCTURE

Top of Knox Group Structure Map (sea level datum)

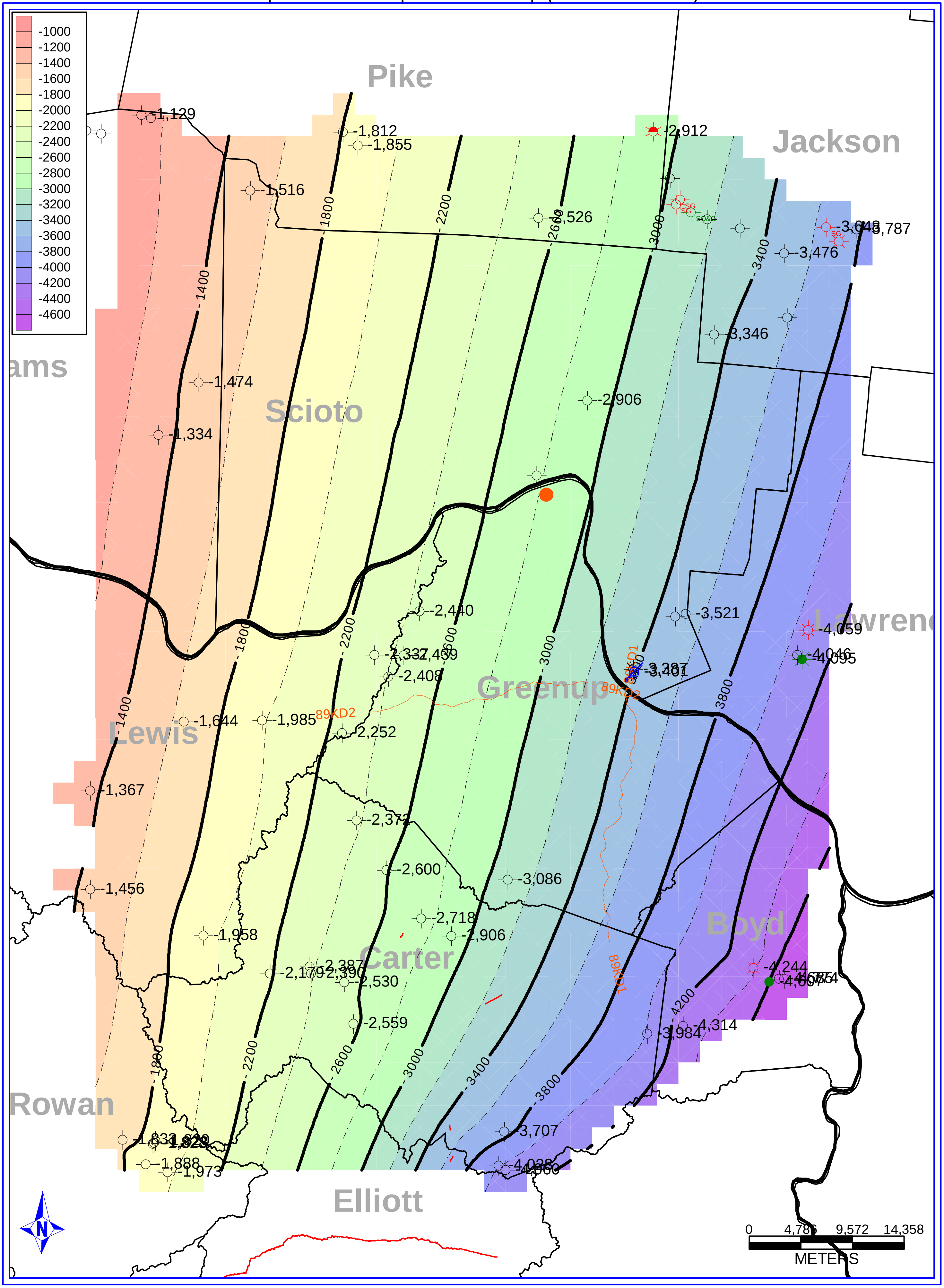

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FIGURE 13

TOP OF COPPER RIDGE STRUCTURE

Top Copper Ridge Dolomite (lower Knox) Structure (sea level datum)

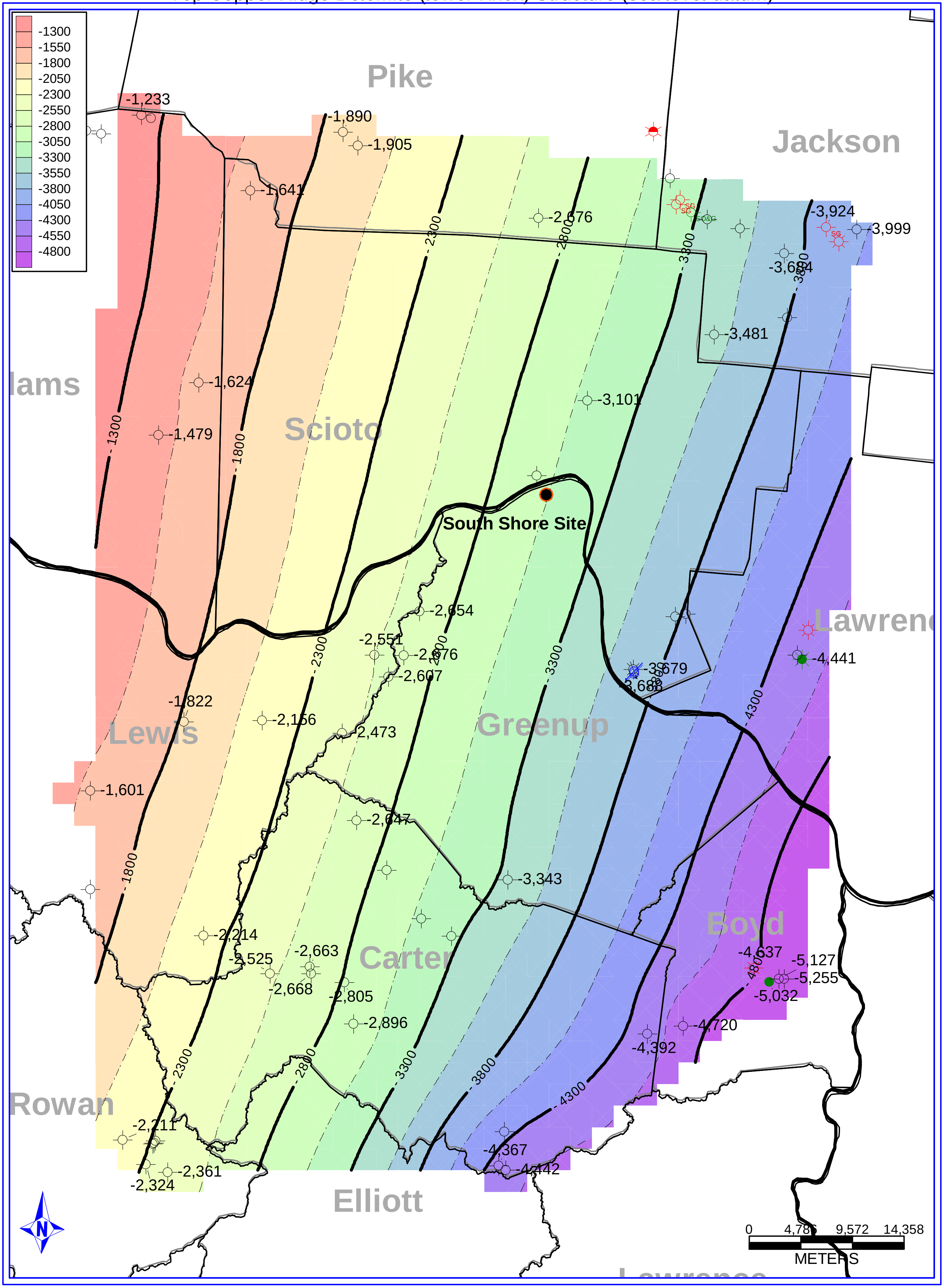

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FIGURE 14

TOP OF PRECAMBRIAN STRUCTURE

Top of Precambrian Basement Structure Map (sea level datum)

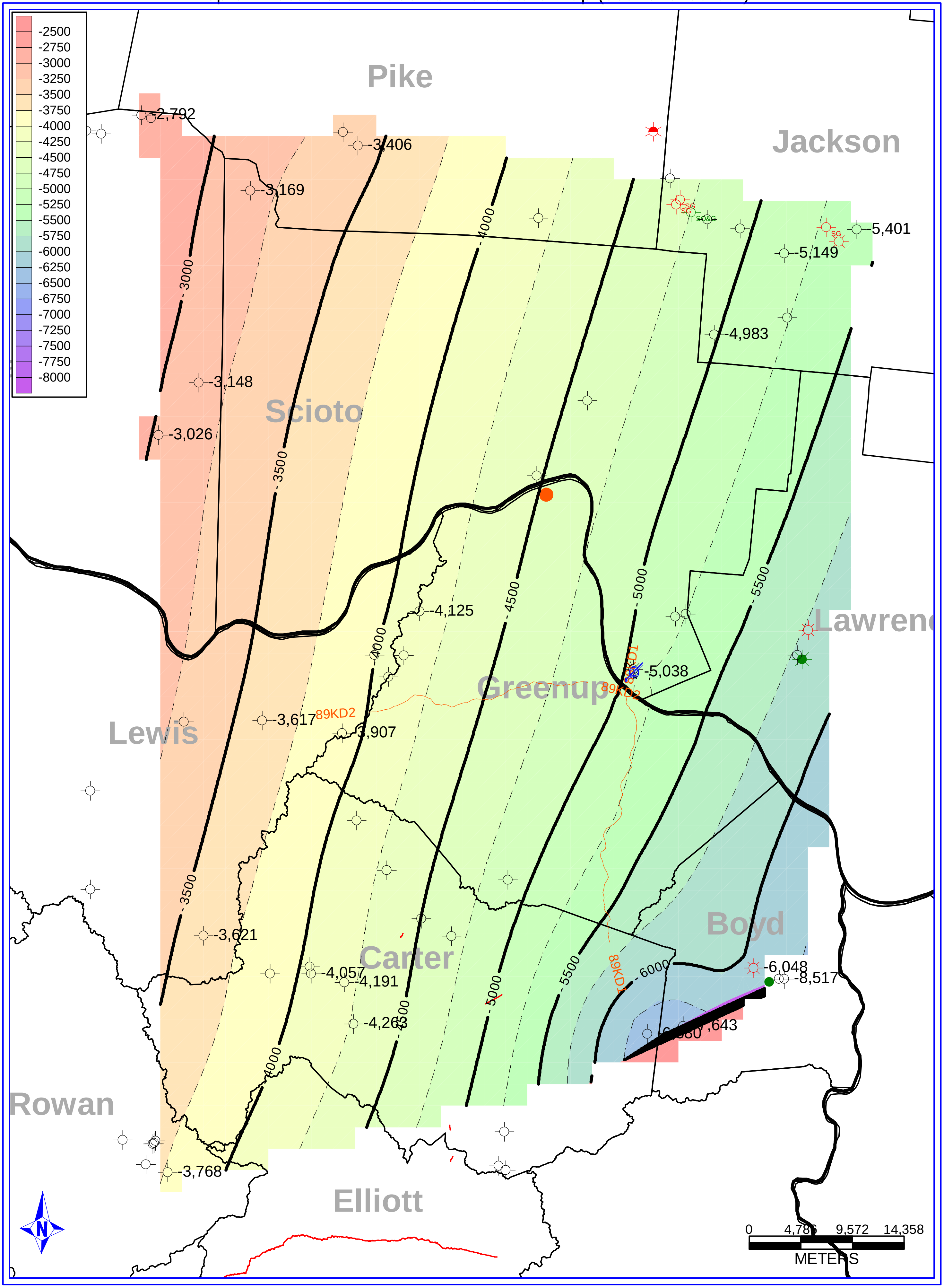

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FIGURE 15

CROSS SECTION INDEX MAP

South Shore Geologic Sequestration Cross Section Index Map

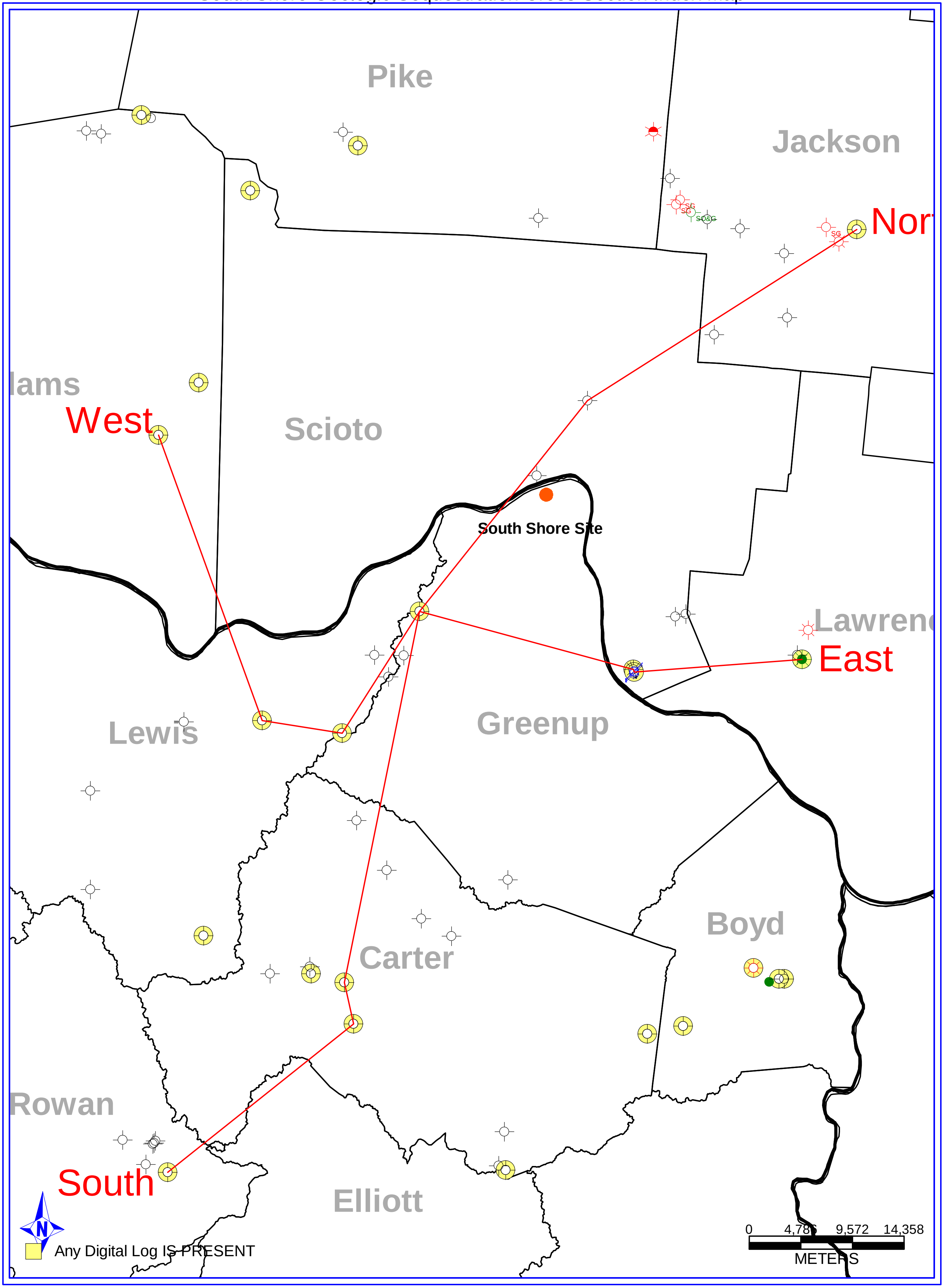

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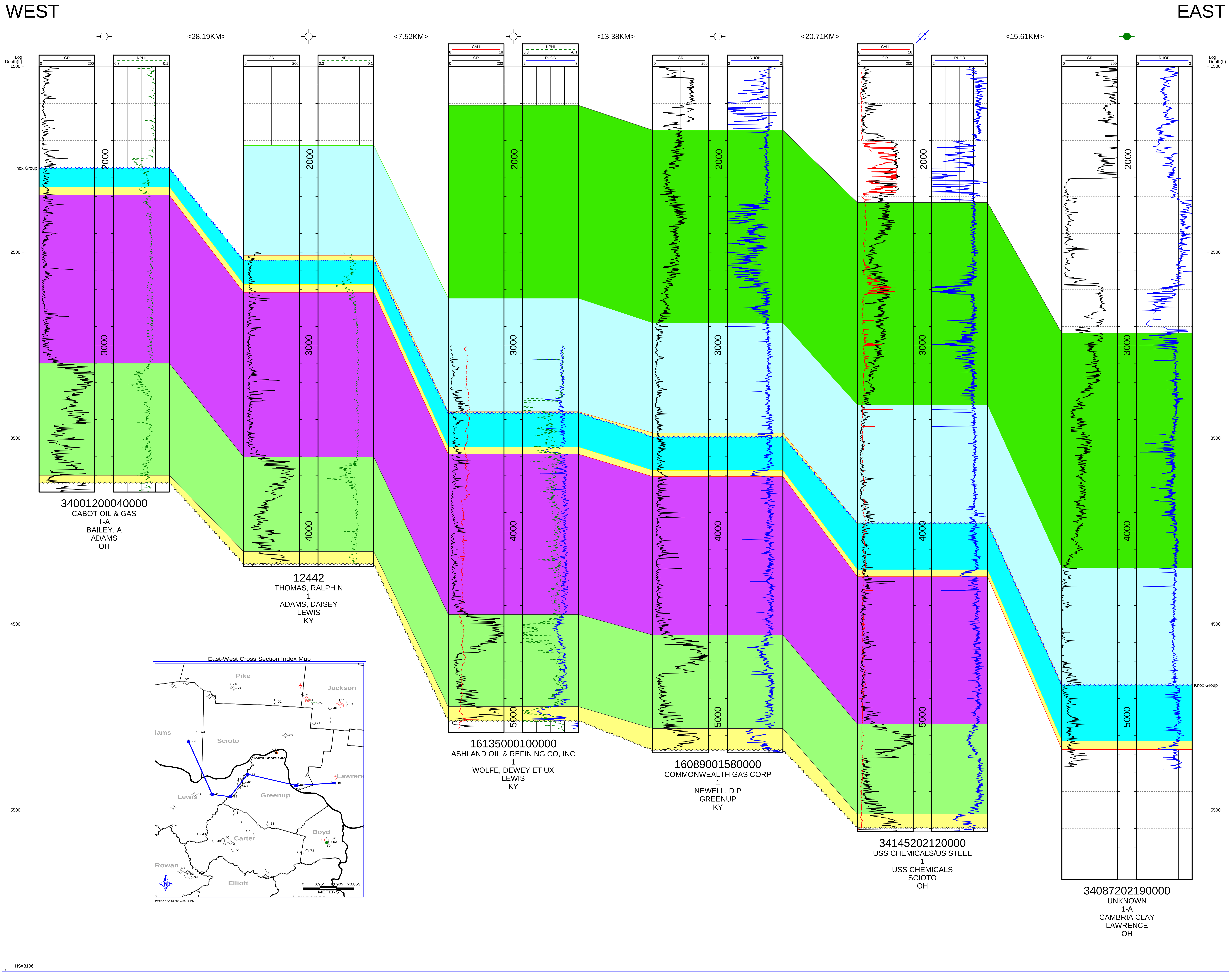
FIGURE 16

EAST – WEST CROSS SECTION

FIGURE 17

NORTH – SOUTH CROSS SECTION

West to East Structural Cross Section



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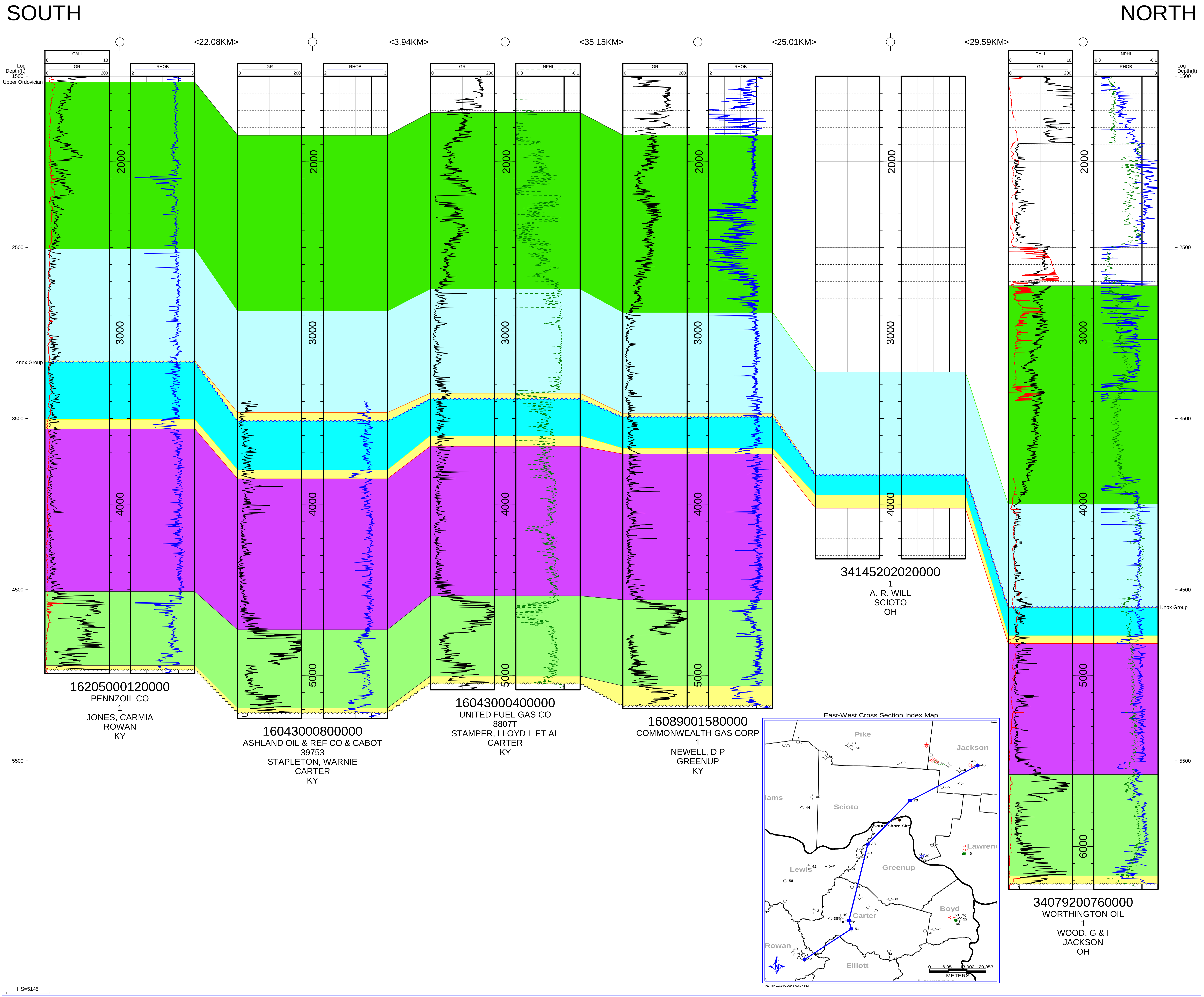
South -North Structural Cross Section



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ATTACHMENT 1 CONTENTS
Battelle Aristech Appendices

Appendix A

Core descriptions

Conasauga Group well APINOs 3414520212, 3414560161, 4710700351

INDUSTRIAL WASTE DISPOSAL #1

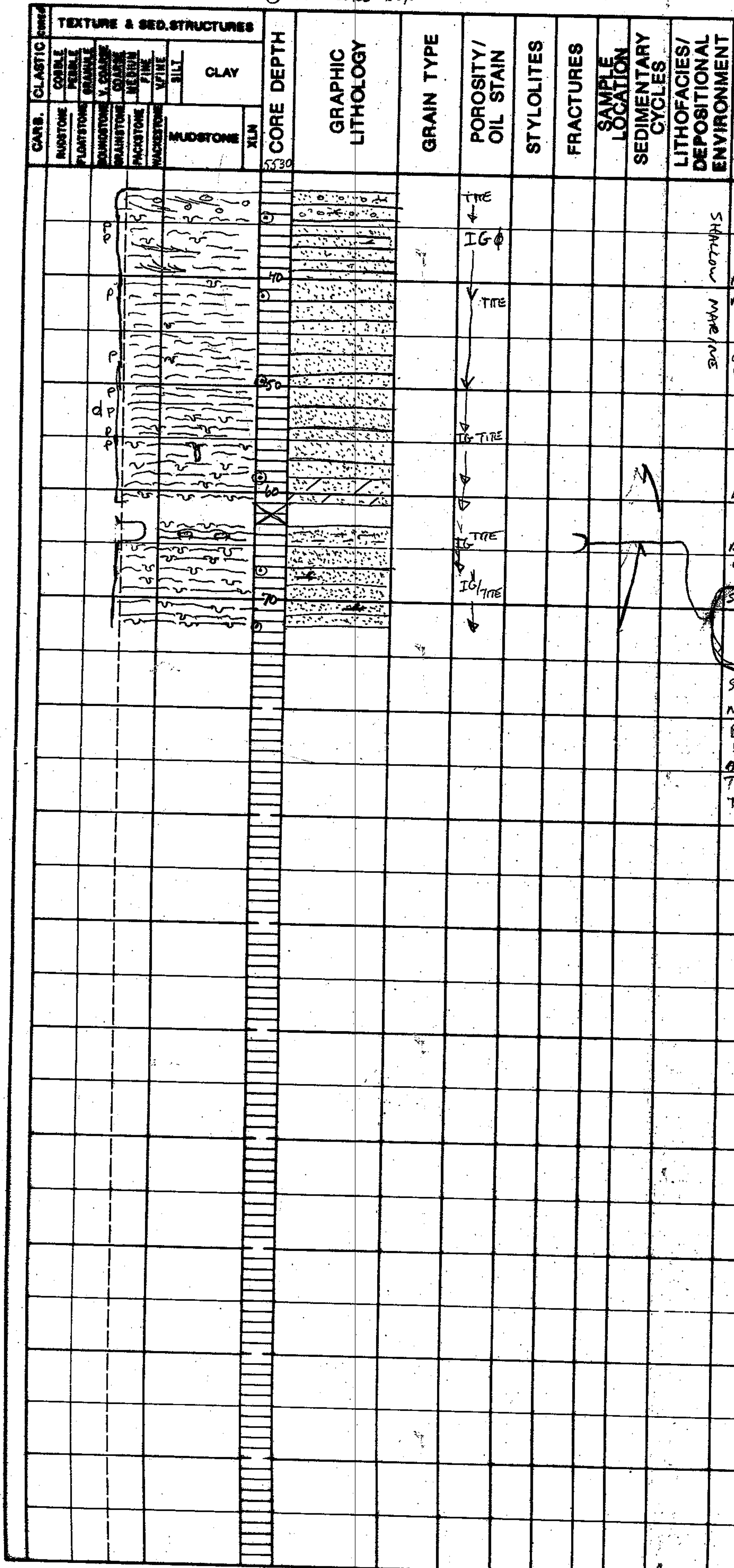
WELL NAME ARISTECH CORP. **DEPTH** 5532.2 **TO** ______ **DATE** 3/7/01

LOCATION GREEN TWP. SCIOTO CO. **CORE(S)** OHIO GEOL. SUR #2958 **DESCRIBED BY** M. BARANOSKI

ROME (JANSSENS)

STRATIGRAPHIC UNIT MARYVILLE **SHEET** 1 **OF** 1 **VERTICAL SCALE** 1" = 10'

⊙ BTM CORE BOX



p = PYRITE

d = discontinuity

DESCRIPTIVE REMARKS

SS LT PINK TO LT. BRN, MASSIVE to IRREGULAR AND WAVY BEDDED, MODERATELY TO POORLY BIOTURBATED, TROUGH X-BEDDING AND FINING UPWARD SEQUENCES, ANHYDRITE REPLACEMENT CLASTS, FELDSPATHIC, MODERATELY TO WELL CEMENTED W/ SILICA AND FELDSPAR, PYRITIC, TR DOL'C AND CALCITE CEMENT, FINE TO MEDIUM GRAINED, POORLY TO WELL SORTED, ROUNDED TO SUBROUNDED MINOR DISCONTINUITIES

DOL, LT PINK TO WH, MASSIVE, IRREGULAR BEDDED, FN TO MED XLN, ARENACEOUS FELDSPATHIC, BIOTURBATED VERTICAL BURROWS, WISPY IRREGULAR LAMINATED DK GRAY SHALE

SS, MED - DK BRN, FN GR, MASSIVE - TO LAMINATED - ARGILLACEOUS BIOTURBATED, INTRAFORMATIONAL BRECCIA 5564.6

SS, SILTSTONE MED - DK BRN, ORANGE, PINK, V FN GRN, MASSIVE, LAMINATED, WISPY, IRREG. BEDDED, BIOTURBATED, VERTICAL BURROWS, TRACE FOSSILS (SCOLITHUS) ON BEDDING PLANE SURFACES TRACE FOSSIL GHOSTS (BRACHIOPODS?) TR DOLO'C

MONITOR WELL (NO.4)

WELL NAME ARISTECH CORP. **DEPTH** 4974.9 **TO** 5100 **DATE** 3/6/01

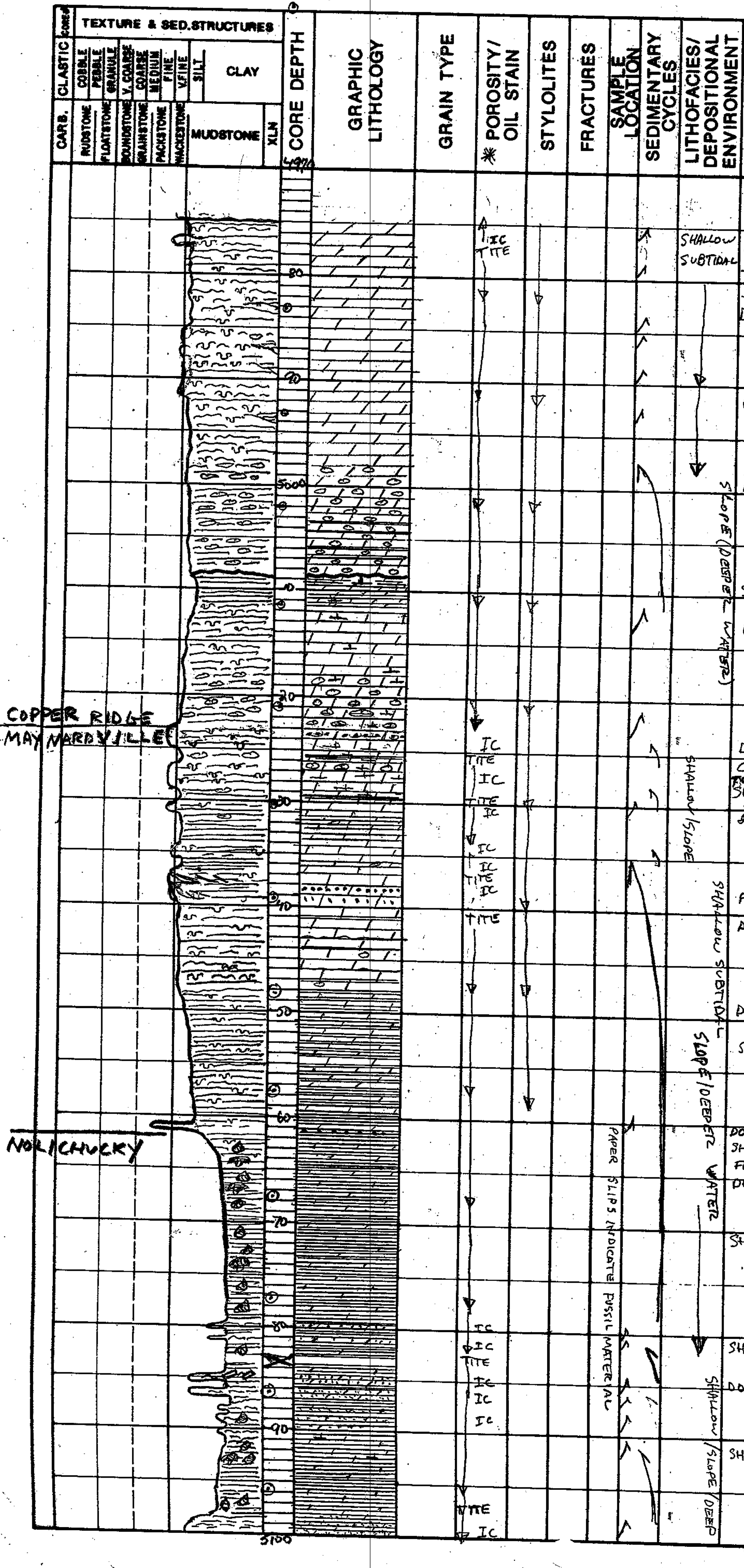
GREEN TWP.

LOCATION SCIOTO CO., OHIO **CORE(S)** OHIO GEOL. SUR. #3409 **DESCRIBED BY** M. BARANOSKI

STRATIGRAPHIC UNIT COPPER RIDGE, MAYNARDVILLE, NOLICHUCKY (CONASAUGA OF JANSSENS) **SHEET** 1 **OF** 4 **VERTICAL SCALE** 1" = 10'

MISSING ✕

DEPTH BTM BOX ⊙



DESCRIPTIVE REMARKS

↰ shallowing upward

↗ fining upwards

COPPER RIDGE DOL.

LOWER PART OF KNOX DOLOMITE

DOLOMITE, LT. TO MED TO DARK BRN, LAMINATED, WISPY, ARGIL LAMINATED TO MASSIVE, RELICT BIOTURBATION, IC ∅ TO TITE, STYLOLITES, SOME STROMATOLITES, SOFT SEDIMENT DEFORMATION, ABUNDANT DISCONTINUITES

DOLOMITE, LT. TO MED. TO DARK BRN, LAMINATED TO WAVY IRREGULAR BEDDED A/A

DOLOMITE A/A NODULAR BEDDED

SHALE DK BRN - BRN, SLI. CALCAREOUS; DOL. A/A

DOLOMITE A/A TITE
SLI CALCAREOUS - INCREASING DOWNWARD

DOLOMITE LT. TO MED. BRN, INCREASING CALCAREOUS NODULES. CONTACT PLACED AT TOP DOLO'C SILTSTONE BED;
SHALE - DK BRN, CALCAREOUS
DECREASING CALCAREOUS NODULAR BEDDING & SHALE

DOLOMITE & SHALE A/A
↳ RELICT BIOCLASTIC GRAINSTONE BEDS
TRACE NODULAR BEDS

POORLY DEV. CROSSBEDS

DOL. A/A TRACE NODULAR BEDS

DOL. A/A INTERBEDDED W/ SHALE
INCREASING SHALE DOWNWARDS
SHALE DK GRAY, LAMINATED, DOLO'C

DOL. A/A INTERBEDDED RELICT BIOCLASTIC GRAINSTONE
SHALE, DK GRY TO BLACK, LAMINATED, DOLO'C, FOSSILIFEROUS; CONTACT GRADATIONAL
DOL. A/A LAMINATED INTERBEDDED W/ SHALE

SHALE A/A INTERBEDDED W/ DOL A/A

SHALE A/A INTERBEDDED W/ DOL. A/A
GRADED FINING UPWARDS
DOL A/A & SILTSTONE W/ INTRAFORMATIONAL CLASTS, RELICT BIOCLASTIC MATERIAL

SHALE A/A INTERBEDDED W/ DOL A/A
↳ SLI. CALCAREOUS

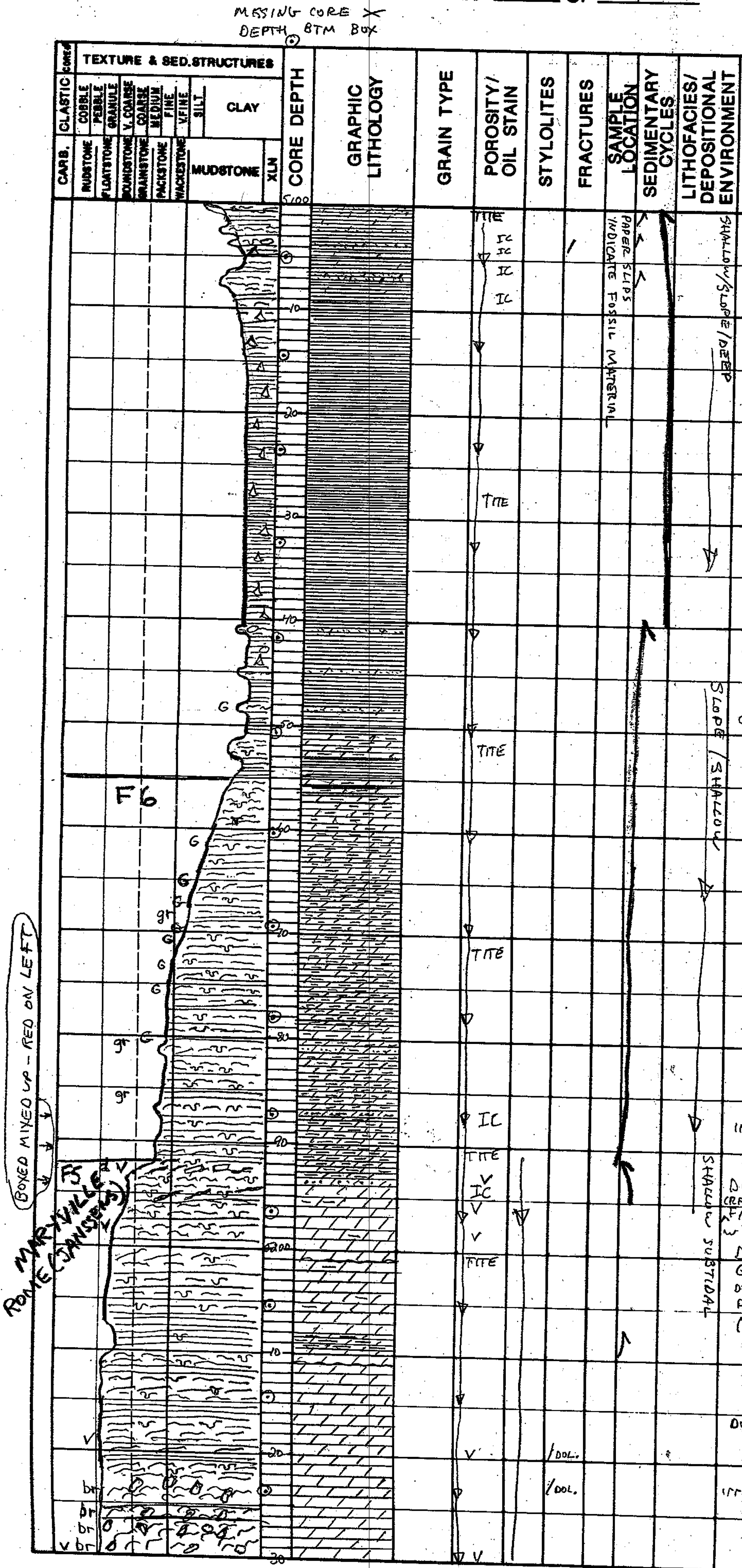
MONITOR WELL (NO. 4)

WELL NAME ARISTECH CORP. DEPTH 5100 TO 5230 DATE 3/6/01

LOCATION GREEN TWP. SCIOTO CO., OHIO CORE(S) OHIO GEOL. SUR. #3409 DESCRIBED BY M. BARANOSKI

STRATIGRAPHIC UNIT NOLICHUCKY, MARYVILLE SHEET 2 OF 4 VERTICAL SCALE 1" = 10'

IC - inter cry. ø
V - vuggy ø
d - discontinuity
br - brecciated
G - glauconite
gr - graded bedding
V = vuggy



DESCRIPTIVE REMARKS

shallowing upwards

fining upwards

DOL. LT. TO MED. BRN LAMINATED, WISPY IRREGULAR BEDDED, RELICT BIOCLASTIC GRAINSTONE BED W/ INTRACLAST MED TO ~~& INTERBEDDED w/ SHALE~~, DK GRAY TO BLACK LAMINATED, FOSSILIFEROUS

SHALE, MED TO DK GRAY A/A, FOSSILIFEROUS

INCREASING INTERLAMINATED AND DOLO'IC SHALE DOWNWARD; INCREASING INTERCLASTS

GLAUCONITE ZONE

F6 CONTACT MARKS LAST MAJOR SHALE BED; CONTACT WITH DOL. GRADATIONAL

GLAUCONITE AND GRADED BEDDING INCREASES DOWNWARDS

INTERBEDDED SHALE A/A & DOL, WHITE TO LT. GRAY, BIOTURBATED

DOLOMITE, WHITE TO LT. GRY, MASSIVE, CRPTXLN, FINELY TO MED. XLN, VUGGY, GRADATIONAL w/ OVERLYING SHALE AND BIOTURBATED DOL.; LOCALLY ARENACEOUS AND GLAUCONITIC; STYLOLITES ABUNDANT, DOLOMITE FILLED FRACTURES, RARE PYRITE; SELENITE FILLED VUGS

(Vugs and rip-up clasts beneath MARYSVILLE CONTACT)

DOL. A/A - LAMINATED TO MASSIVE BEDDED; LOW ANGLE BEDDING DIP?

irregular fractures - dol. filled

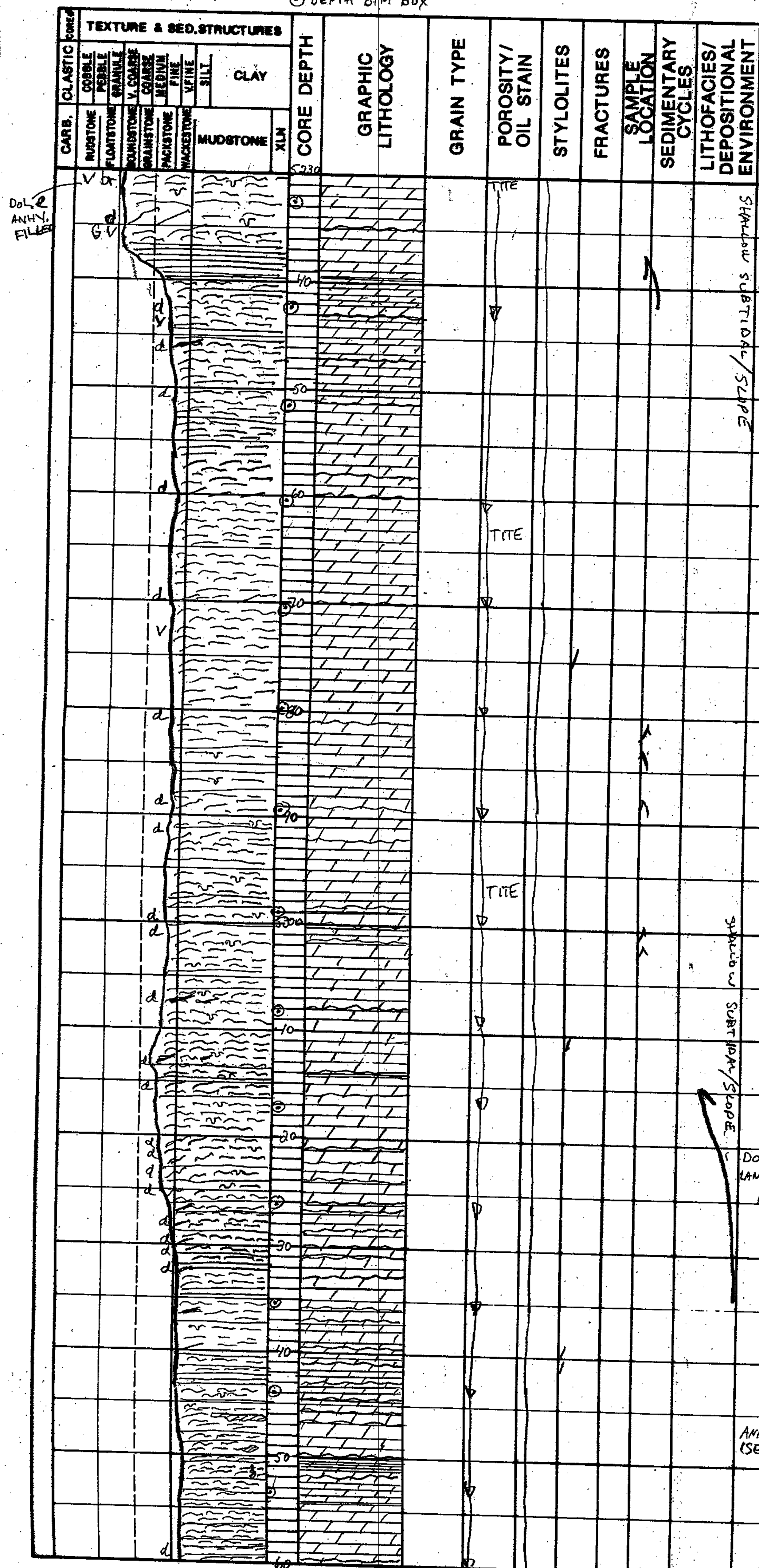
MONITOR WELL (NO. 4)

WELL NAME ARISTECH CORP. DEPTH 5230 TO 5360 DATE 3/6/01

LOCATION GREEN TWP, SCIOTO CO., OH CORE(S) OHIO GEOL. SUR. #3409 DESCRIBED BY M. BARANOSKI

STRATIGRAPHIC UNIT MARYVILLE (ROME & JANSSENS) SHEET 3 OF 4 VERTICAL SCALE 1" = 10'

⊙ DEPTH BTM BOX



DESCRIPTIVE REMARKS

WISPY, IRREG.

DOL. - WH to LT/MED GRY, LAMINATED, TO MASSIVE BEDDED, CRPTYLN, FN TO MED XLN, LOCALLY ARENACEOUS, POORLY DEVELOPED BIOTURBATION, SLIGHTLY VUGGY, HIGH ANGLE DISCONTINUITIES. INTERLAMINATED MED TO DK GRY SHALE, BRECCITED SHALE CLASTS, ABUNDANT STYLOLITES, DISCONTINUITIES/SCOUR SURFACES COMMON

DOL A/A, SH A/A - INCREASING DOWNWARD LAMINATED, WISPY, IRREGULAR BEDDED SHALEY DISCONTINUITIES/SCOUR SURFACES COMMON

ANHYDRITE BED/NODULE (SELENITE)

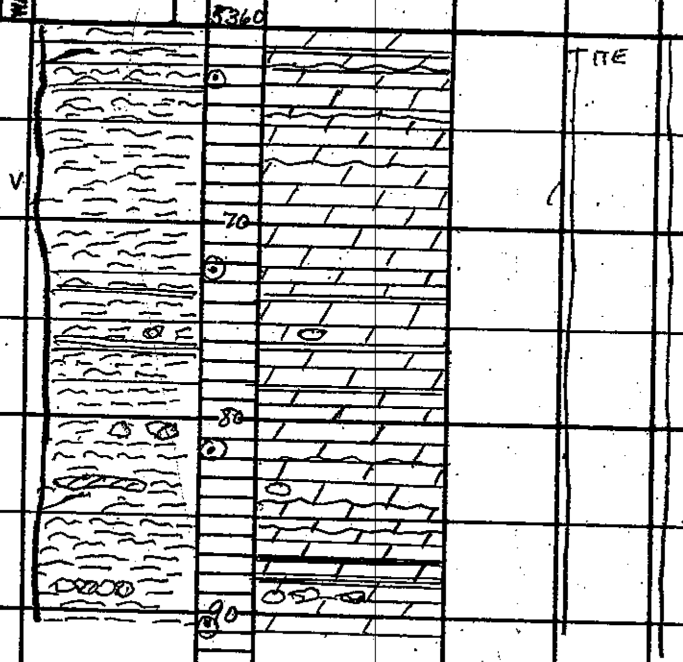
WELL NAME ARISTECH CORP. DEPTH 5360 TO 5390.9 DATE 3/7/01

LOCATION GREEN TWP. SCIOTO CO., OHIO CORE(S) OHIO GEOL. SUR #3409 DESCRIBED BY M. BARANOSKI

STRATIGRAPHIC UNIT MARYVILLE (ROME OF JANSSENS) SHEET 4 OF 4 VERTICAL SCALE 1" = 10'

⊙ BTM CORE BOX

TEXTURE & SED. STRUCTURES | CORE# | CLASTIC: COBBLE, PEBBLE, GRANULE, V. COARSE, COARSE, MEDIUM, FINE, V/FINE, SILT, CLAY | CARB.: RUDSTONE, FLOATSTONE, BOUNDSTONE, GRAINSTONE, PACKSTONE, WACKESTONE, MUDSTONE, XLN | CORE DEPTH | GRAPHIC LITHOLOGY | GRAIN TYPE | POROSITY/ OIL STAIN | STYLOLITES | FRACTURES | SAMPLE LOCATION | SEDIMENTARY CYCLES | LITHOFACIES/ DEPOSITIONAL ENVIRONMENT | DESCRIPTIVE REMARKS



DOL. - LT to MED GRY, CRYPT-FNXLN, LAMINATED, WAVY BEDDED: INTERBEDDED THIN LAMINATED WISPY IRREG MED TO DK GRAY SHALE, DISCONTINUITIES/SCOUR SURFA
COMMON

ANHYDRITE (SELENITE) FILLED VUGS

BRECCIA

ANHDRITE (SELENITE)

BRECCIA / W ANHYDRITE (SELENITE) FILL

HOPE NAT. GAS

core images available

WELL NAME #9634 Power Oil Co. **DEPTH** 13,005 **TO** 13,060 **DATE** 5/10/01

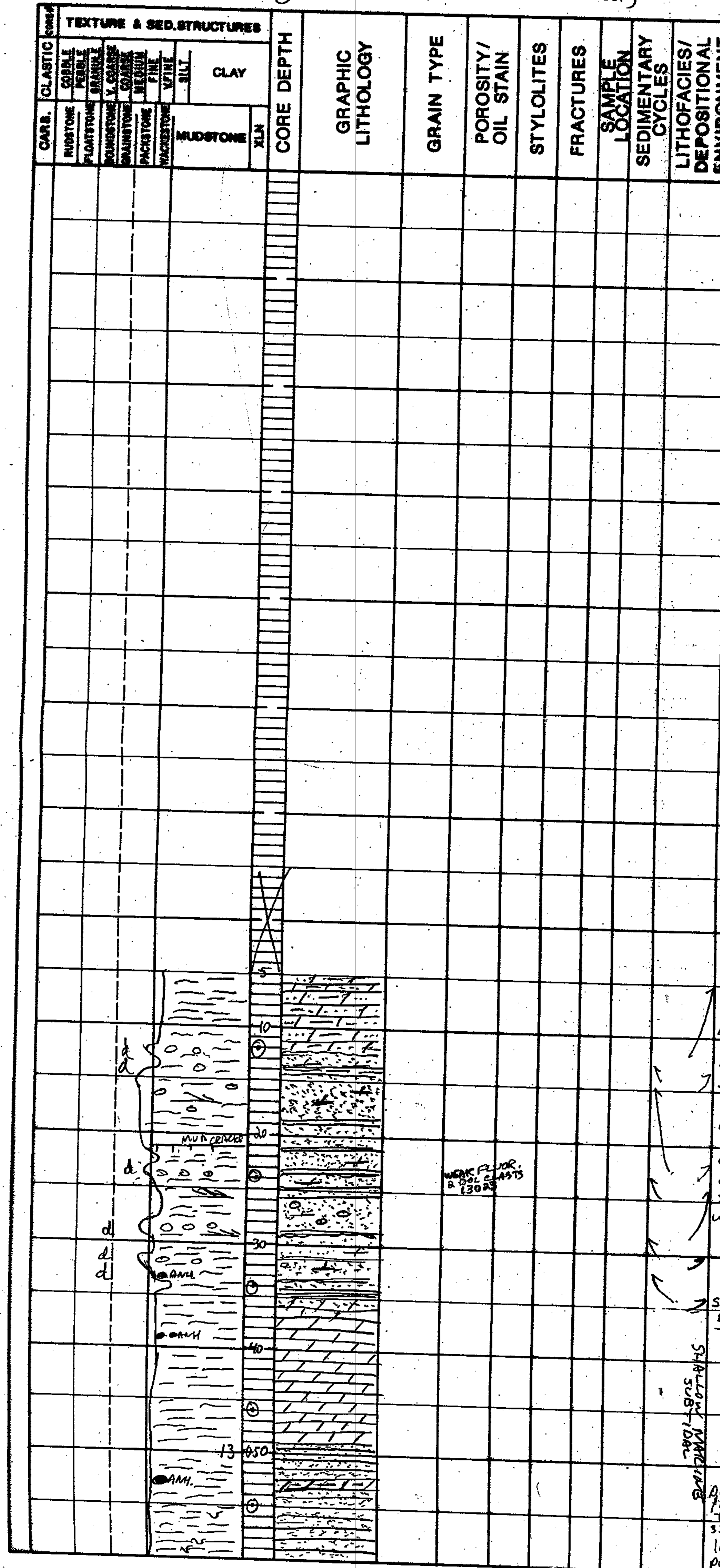
LOCATION Wood Co., WV **CORE(S)** 768 **DESCRIBED BY** MTB

MARYVILLE LS.

STRATIGRAPHIC UNIT JANSSENS MNSM **SHEET** 1 **OF** 2 **VERTICAL SCALE** 1" = 10'

CONASAUGA GP.

⊙ BOTTOM CORE BOX (LOWER LEFT ON BOX)



DESCRIPTIVE REMARKS

↑ coarsening upwards

↗ fining upwards

d - discontinuity

P - pyrite

● nodular

○ clasts

DOL - MED GRAY, FN XLN - CRPTOXLN, MASSIVE TO LAMINATED/IRREGULAR BEDDED ARENACEOUS, ARGILLACEOUS, RARE NODULAR

ss/siltstone/sh - lt brn, gry, redgry, green fn - med grn - poorly to mod srted intraformational conglomerate, doloic mudcracks; numerous fining upward cycles; punctuated by coarse cycles; anhydrite nodules at bottom of sequence discontinuities in part angular. some X-bedding developed, irregular wispy bedded. contacts may be thin paleosols?

sh/silt - laminated, burrowed LT BRN

DOL - LT GRAY, FN XLN - ARENACEOUS AT TOP OF SEQ. / - DOL MED - DK GRAY AS BELOW

DOL - med-dkgry, fn to cryptxln, oolith ghosts laminated to massive bedded, irregular fractures filled w/DOL.; ANHY NODULES

ss/silt, lt br, medgray, fn grn, sl. doloic laminated to irregular, wispy bedded poorly dev. bioturbation, argillaceous

1110100551 HOPE NAT. GAS

WELL NAME #9634 POWER OIL CO. **DEPTH** 13060 **TO** 13312 **DATE** 5/10/01

LOCATION WOOD CO. WV **CORE(S)** 768 **DESCRIBED BY** WJB

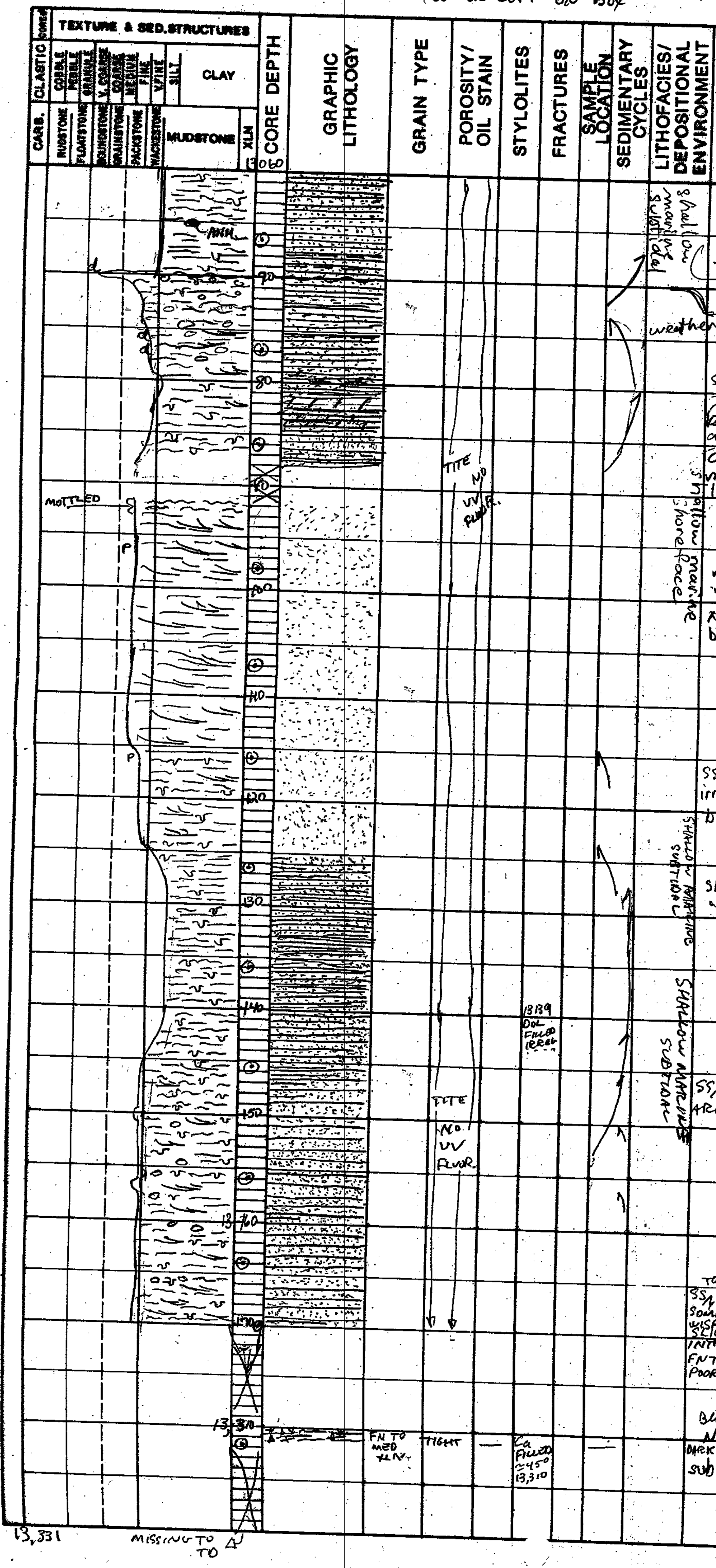
MARYVILLE LS.

STRATIGRAPHIC UNIT JANSSENS MASM 9PCMB **SHEET** 2 **OF** 2 **VERTICAL SCALE** 1"=10'

CONASAUGA GP.

✕ MISSING

⊙ DEPTH BTM. BOX (LOWER LEFT ON BOX



coarsening

fining

DESCRIPTIVE REMARKS

p-pyrite ○ clasts

d-discontinuity

● NODULAR

ss/silt, lt. brn, gray, med gry fn grn, irregular bedded to laminated; interbedded w/ sh-med to dark gray → poorly dev. X-bedding/bioturb. anhydrite nodules ⊙ 13,065. trace calcite

weathered paleosols? 13070 to 13077

ss, silt, wh-medgray, grn gry, red gry, DOLO'L interbedded with shale med gry, grn gry, reddish gray mottled, fn grn, argillaceous, irregular bedded, to massive, poorly dev. X-bedding and bioturbation; intraform. conglom.

dol. lt. to med gry, ~~to~~ lt brn, fn to med xln, cryptoxln, arenaceous, bioturbation laminated to wispy irr bedded

silica

ss-wh. to lt./med. brn. to gray, fn to med grained, rnd to subang; poorly to mod. srtd, silica cement, massive, xbedded, laminated, poorly dev. bioturbation, mottled

ss/silt - lt gray, lt brn, gray, fn grn, irregular - wispy bedded to massive bioturbated, poorly dev. xbedding

sh-black-dark gry, micaceous, tr. dolo'c; interbedded w/ ss/silt as below.

SS, SILT AS BELOW, BECOMING MORE ARGILLACEOUS UPWARD; soft sed. def.

SS, TO SILT. LT. TO MED. GRAY, LT BRN, LAMINATED, SOME MASSIVE BEDDING, BIOTURBATED / WISPY IRREGULAR BEDDING, X-BEDDING, SLIGHTLY ARGILLACEOUS, INTRAFORMATION CLASTS / BRECCIA, ARGILLACEOUS FN TO MED. GRAINED, SUBANG TO ROUNDED, POORLY TO MOD. SORTED; MINOR DISCONTINUITIES

Black to PINK TO ORANGE N1-N2; SR 8/2; 10R 6/6

DARK HORNBLENDE SCHIST?; granite gneiss; sub horizontal schistocity.

APPENDIX AA

ANALYSIS OF DST DATA FROM ARISTECH WELLS, 1989
(MEMO FROM REC TO ARISTECH)

P4-91

002639

Box 37

MEMORANDUM

June 20, 1989

TO: Paul Kaplow/Aristech and John Fleniken/Envirocorp

FROM: Gene Collins / REC

RE: Analysis of DST data from Aristech Wells

Objective: REC has been requested to evaluate pressure data obtained in the Rose Run formation by a drill stem test (DST) in WDW No. 3 at the Aristech site in Scioto County, Ohio in May, 1989. These data are to be compared to results of the DST in the Rose Run in WDW No. 1 at this site in June, 1968.

Mr. Harlan Gerrish of the USEPA Region V, Chicago, Illinois has contended that these two tests indicate a **pressure rise** in the Rose Run of approximately 100 psi since 1968. REC has been asked to determine whether this is reasonable, based upon these data.

Method: The first step was to extrapolate the shut-in pressures for the second shut-in period of each DST test by using the Horner plot technique. This is a standard, well accepted method for determining shut-in pressures. This is a plot of shut-in pressure versus $\ln (t + \Delta t) / \Delta t$, where t is the duration of the second flow period and Δt is elapsed shut-in time in the second shut-in period. Theory [Horner (1951)] shows that these data should approach a straight line for larger Δt with intercept P^* as $\Delta t \rightarrow \infty$, where P^* is the true shut-in pressure after all transients due to the flowing tests have disappeared.

The Horner plot for the 1989 Rose Run DST in WDW No. 3 is shown in Figure 1, while that for the 1968 Rose Run DST in WDW No. 1 is shown in Figure 2. Also shown in Figure 3 is the plot for the DST in the Mt. Simon formation obtained in WDW No. 1 in 1968 prior to beginning injection in the Mt. Simon. The resulting extrapolated P^* pressure values are shown in Table I along with other pertinent data from these tests.

Table I

Well	Date	Formation	Gauge Elev. (ft.,True S.L.)	P^* Psi	Brine Sp.Gr.
WDW#1	5/25/68	Rose Run	-3673	1896	1.199
WDW#1	6/ 6/68	Mt. Simon	-4988	2633	1.255
WDW#3	5/15/89	Rose Run.	-3706	1969	N/A

Data Corrections and Discussion: Valid comparison of P^* values for the Rose Run between the two wells requires that these be corrected for depth to a common datum relative to sea level. This difference in elevation between the two wells results in a naturally occurring higher pressure in the Rose Run in WDW No. 3 over that in WDW No. 1 by:

$$\Delta P = .433 \times 1.199\ (3706 - 3673)$$

$$\Delta P = 17.13 \text{ psi}$$

Thus for the Rose Run, the pressure in WDW No. 3, corrected to the <u>same elevation</u> as in WDW No. 1, is:

$$P^*_{cor.} = 1969 - 17.13 = 1951.9 \text{ psi}$$

which is still higher than that in WDW No. 1 by 55.67 psi.

However, it appears that the DST data in WDW No. 1 are in error because the P^* value from the DST, in relation to that for the Mt. Simon, varies from a well established relationship. (hydrostatic equilibrium consistency) Hydrostatic consistency between the Rose Run and Mt. Simon in 1968 is tested as follows:

Letting:

P_1^* = (Rose Run, 1968 WDW No. 1)
P_2^* = (Mt. Simon, 1968 WDW No. 1)

with d_1 and d_2 corresponding depths, we see that hydrostatics would require

$$P_2^* - P_1^* = 0.433 \frac{\gamma_1 + \gamma_2}{2} (d_2 - d_1) = 0.433\,\gamma\ (d_2 - d_1)$$

where γ_1 and γ_2 are the respective specific gravities. Using the P^* values above, we compute the average of these, γ, implied as

$$\gamma = \frac{P_1{}^* - P_2{}^*}{.433\ (d_2 - d_1)} = \frac{2633 - 1896}{.433(4988 - 3673)}$$

or $\gamma = 1.294$

This differs markedly from $(\gamma_1 + \gamma_2) / 2$ which is 1.227. Thus it appears that $P_1{}^*$ and/or $P_2{}^*$ are in error since specific gravities are measured with greater accuracy and precision than DST pressures.

If we assign all of this inconsistency to the Rose Run pressure, we can use hydrostatics to compute a corrected Rose Run P^* value from the Mt. Simon value. This is by using:

$$P_1{}^* = P_2{}^* - 0.433 \frac{\gamma_1 + \gamma_2}{2} (d_2 - d_1)$$

which is:

$$P_1{}^* = 2633 - 0.433\ (1.227)\ (4988 - 3673)$$

or

$$P_1{}^* = 1934.4 \text{ psi}$$

This value for P^* in the Rose Run in WDW No. 1 is 38.4 psi **higher** than the value from the DST.

Thus, with the datum corrected value for P^* of the Rose Run in No. 3 and the hydrostatic corrected value for P^* in the Rose Run in No. 1, we see a difference,

$$(P^*_{\text{cor.}}\ \text{No. 3}) - (P^*_{\text{cor.}}\ \text{No. 1}) = 1951.9 - 1934.4$$

$$= 17.5 \text{ psi}$$

This difference in pressures (at the same elevation datum) is within the range of error of mechanical gauges used in 1968. [Errors of = ±10 psi are not uncommon in older gauges]

Reference

Horner, D.R.; Proc. 3rd World Pet. Cong., Sect. II, E. J. Brill, Leiden (1951).

DRILL STEM TEST, 5/15/89
Aristech Chemical Corporation
Final Shut-in Period, WDW No. 3
Rose Run Formation, Scioto County, Ohio
Test Depth – 3706 Feet True Vertical Sub-Sea Depth

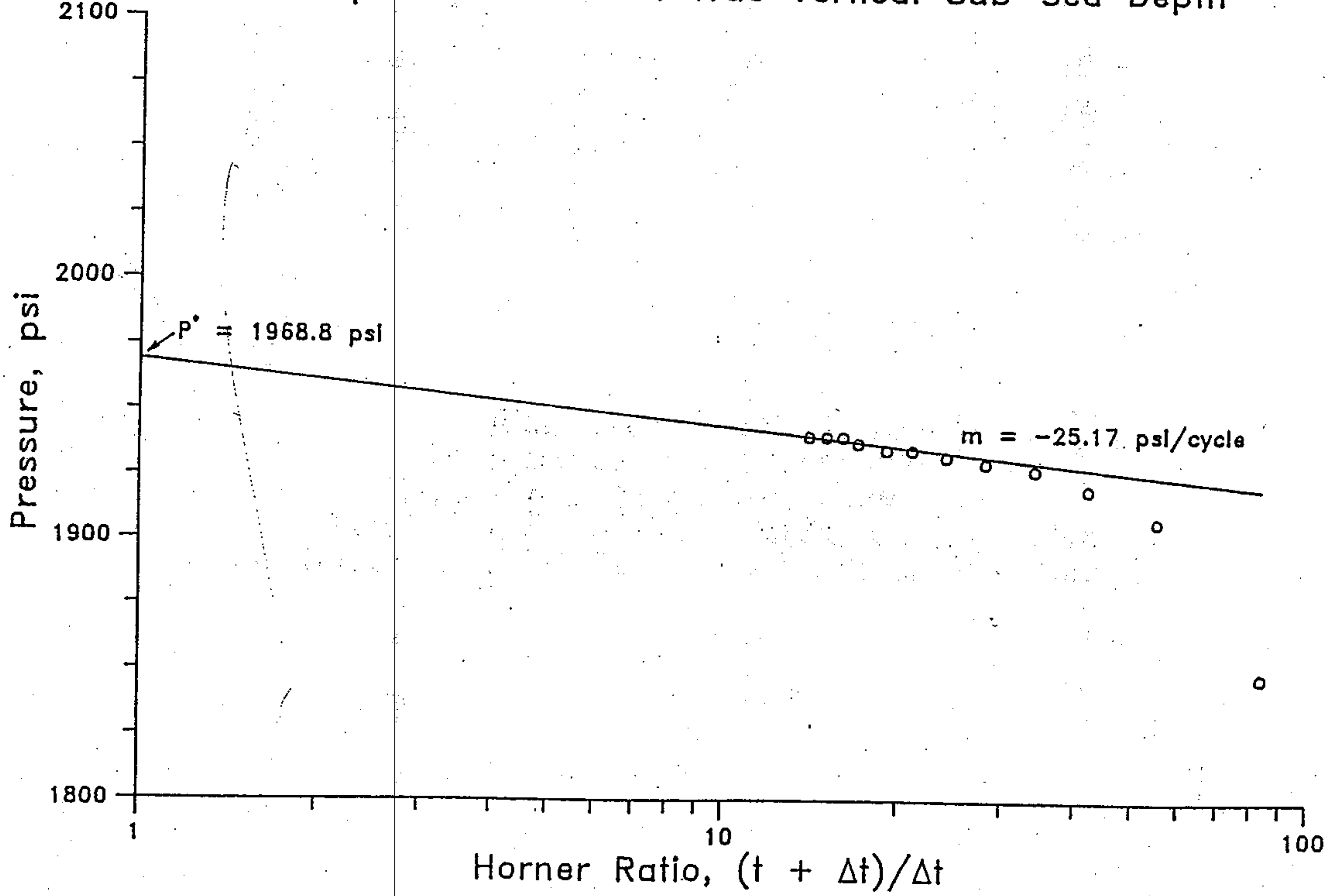


Figure 1

REC, INC.
June 1989

DRILL STEM TEST, 5/25/68
Aristech Chemical Corporation
Final Shut-in Period, WDW No. 1
Rose Run Formation, Scioto County, Ohio
Test Depth – 3673 Feet True Vertical Sub-Sea Depth

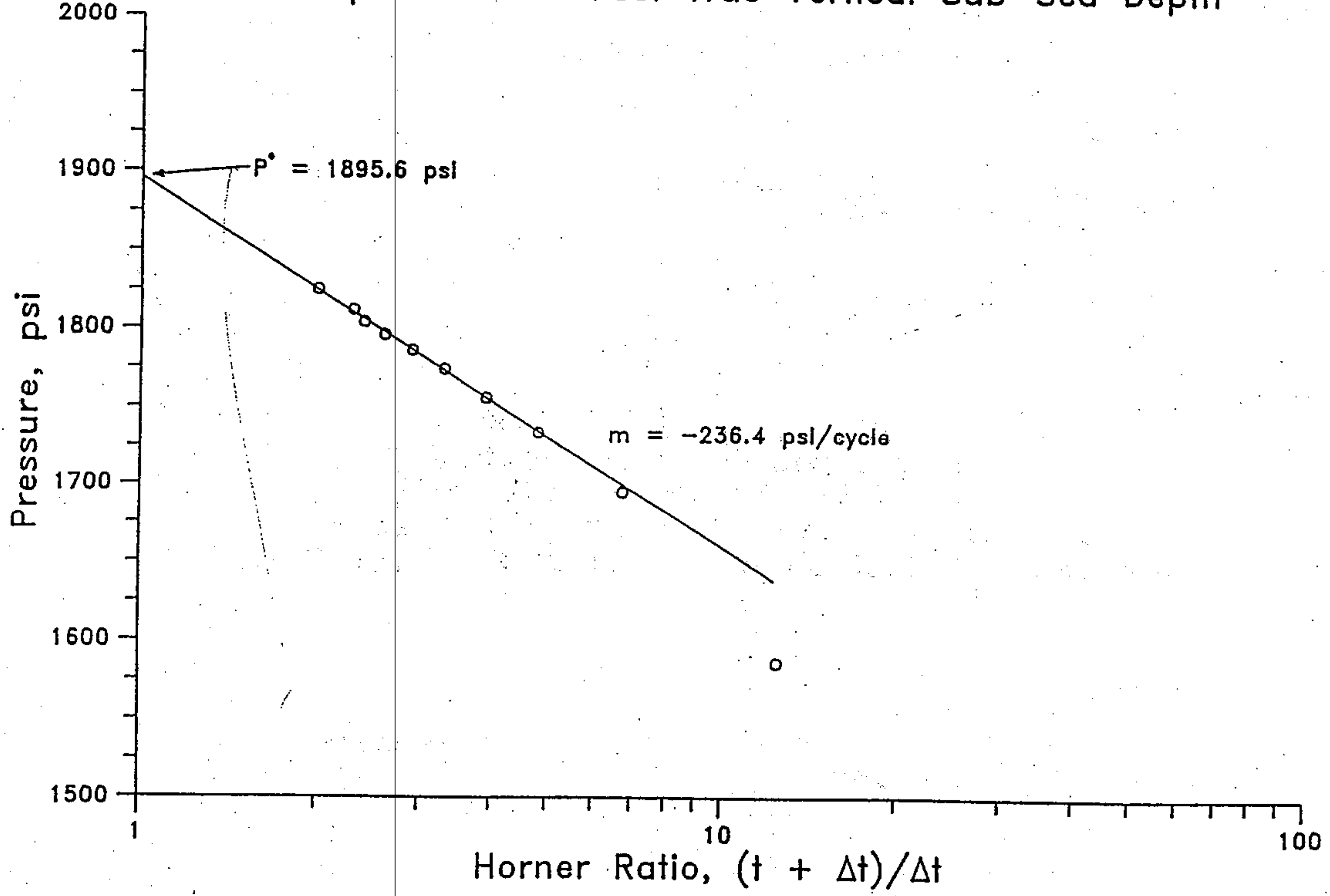


Figure 2

REC, INC.
June 1989

DRILL STEM TEST, 6/6/68
USS Chemicals
Final Shut-in Period, Haverhill Disposal Well No. 1
Mt. Simon Sand, Scioto County, Ohio
Test Depth – 4988 Feet True Vertical Sub-Sea Depth

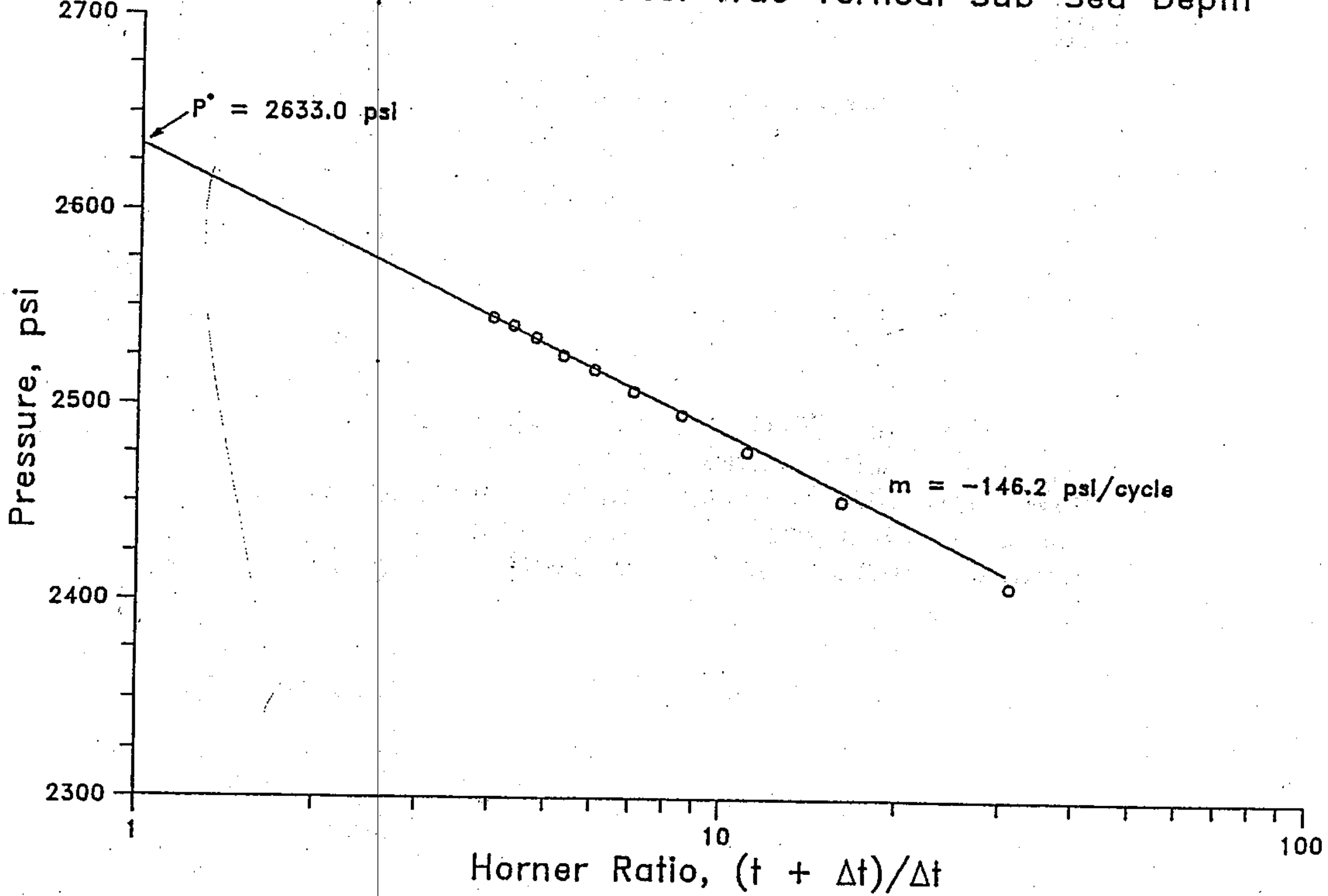


Figure 3

REC, INC.
June 1989

APPENDIX BB

SUMMARY OF STUDIES PERFORMED AND METHODOLOGIES

002639

Box 37

P4-91

A. Organic and Inorganic Geochemistry

As summarized in previous sections, biogeochemical studies were conducted to determine fate and transport of chemical constituents. The chemical conditions within the hydrologic system were assessed (e.g., anaerobic vs. aerobic, saline vs. fresh water, host rock-fluid interaction, etc.), as well as both the potential for biodegradation and resulting compound-specific biodegradation products.

A number of transport and transformation processes can affect the concentrations of these compounds as the fluids migrate. These include volatilization from water to vapor phase (if present), cation exchange, and oxidation. The importance of each of these mechanisms was also assessed. Adsorption of both organic and inorganic constituents onto rock matrix and the potential for differential contaminant movement were examined, as well as a number of chemical transformations such as pH changes and the potential addition of other inorganic species through dissolution. These detailed chemical assessments were conducted to obtain a clear understanding of both the chemical system and potential chemical interactions.

B. Organic Chemical "Fingerprinting"

Groundwater samples from the Rose Run and injectate were reanalyzed using state-of-the-art LC/MS/MS techniques, wherein very detailed, compound-specific analyses are being conducted. Results of these analyses are pending. The results of chemical fingerprinting are included in Section IV of this report.

C. Hydrogeologic and Geologic Assessments

As previously stated, a site-specific geohydrologic assessment was conducted as part of the UIC petition and provided a good understanding of regional geology. A summary of the site and regional hydrogeologic conditions was discussed in Section III above. In the UIC study, a detailed examination (microscopic) of the core (Appendix A) was also conducted to provide detailed mineralogical information, and well logs (Appendix T), drilling data, and literature reviews all provided additional geologic information. Although hydrologic information in the area is limited, the Project Team assembled and interpreted available information to acquire an understanding of the hydrogeologic conditions (Appendix C). A regional structural geology (lineament) study was also conducted, wherein geomorphic and geophysical data were integrated to assess the nature of structural features.

D. Geophysical Information and Well Construction Assessments

Geophysical studies were conducted to provide both detailed site-specific and regional geologic, hydrologic, and geochemical support information. For example, Schlumberger was retained to assess whether the organic fluid content of the groundwater could be determined using well log data (Appendix F). A regional seismic survey was conducted to evaluate large-scale structural characteristics that were not apparent in cores or in the geologic literature (Appendices D and E). Well histories were studied, and mechanical integrity tests (MITs) were examined to assess well construction (Appendix G and H). The chemical nature of drilling fluids that were used during drilling of WDW No. 3 was also evaluated (Appendix U).

In addition, an aerial photography survey was conducted to examine historic land use in the facility area; the results of this survey prompted Aristech to conduct a field magnetometer survey over an approximately 1000 square foot area. The purpose of this magnetic survey was to determine if buried metal is present at the site, including, possibly, metallic well conductor casing that could be present. Results of this survey are included in Appendix V.

E. Data Validation, QA/QC

A large quantity of data collected from a number of sources and analyzed by various laboratories were used for this assessment. The use of quality data was a high priority for the project. Therefore, the Project Team conducted comprehensive data validation and quality assurance (QA)/quality control (QC) exercises for all data --geologic, chemical, hydrologic, geophysical, MIT, etc. These exercises assured that only the most reliable information was used in assessments (Appendices L and W).

F. Additional Site Studies

To complete this assessment and as discussed above, the Project Team evaluated the historic production at the Haverhill facility, as well as the manufacture of similar products (and waste disposal practices) in the Haverhill area. Harrison/Kroll conducted comprehensive interviews of area residents/employees, which also included a study of historic phenol manufacturing processes in the Haverhill region. Also, wells in the Aristech area that were drilled into the Rose Run Formation were identified (Appendix K). ERM also conducted a well and industry survey within a 50-mile radius of the Haverhill facility (Appendix X). Aerial photographs taken between 1951 and 1988, covering an approximately 10-mile radius surrounding the facility, were also examined. A field survey of the area immediately surrounding the facility was conducted, as well as a field magnetometer survey (Appendix V).

Appendix B

Miscellaneous test and analyses

APINO 3408720219 completion and DST data Knox dolomite

Arrington well DST results APINO 4705300069 Maryville Limestone DST (no pressures) brine analyses (Overbey, 1961).

OVERBY (1961)

Cambrian System

Upper Cambrian

Trempealeau Formation—This formation, composed mainly of brownish-gray dolomite in the Mason-69 deep well, may range in thickness from 400 to 600 feet in the area of the report. It is generally finely crystalline with scattered sand layers and small amounts of gray shale.

ARRINGTON

Franconia-Dresbach Formation—In the Mason-69 deep well, this formation is a white to light brownish gray, finely crystalline, sandy dolomite, 199 feet thick. The maximum thickness in this area is probably 400 feet.

Eau Claire Formation—This unit is composed of greenish gray and brown silty, dolomitic shales and dolomites. The estimated range in thickness is 460 to 600 feet. In the Mason-69 well the Eau Claire is 403 feet thick.

Mt. Simon Sandstone—A sandstone with shaly and dolomitic interbeds, the Mt. Simon is 116 feet thick in the Mason-69 well and may range to 250 feet thick in the area of this report.

Basal Complex—In the Mason-69 well, 77 feet of the basement complex, supposedly of pre-Cambrian age, was penetrated. The upper 22 feet or so consisted of a granite wash and the lower 55 feet was composed of a material resembling micaceous gneiss or a chlorite schist.

EXAMINATION OF MASON COUNTY BASEMENT TEST

Only two wells have penetrated the entire thickness of sedimentary rocks in West Virginia: The Sandhill well in Wood County, which has been thoroughly covered in the Survey Report of Investigations No. 18, and the Grover Arrington No. 1 well in Mason County. The log of the Mason County well is included here.

The author wishes to acknowledge the aid of Dr. Ping-fan Chen, Petroleum Geologist, of the Survey, whose partial log of this well from 3,300 feet to total depth was consulted.

Grover Arrington No. 1 Well (Permit Mason-69)

By United Fuel Gas Company, Clendenin District; elevation 597.22'; located 2.50 mi. S. of 38° 45'; 4.12 mi. W. of 82° 05'.

Drilling began June 7, 1959, and was completed on August 8, 1959. It was a dry hole. Four drill stem tests were attempted, the results of which were as follows:

Zone #1, from 7662 to 7672 feet showed salt water; total chloride, 112,500 ppm.

Zone #2, from 7643 to 7663 feet showed salt water; total chloride, 183,000 ppm.

Zone #3, from 6682 to 6687 feet, packer failed, no test.

Zone #4, 6669 feet, packer failed, no test.

3408720219

ANALYSES FILES

JADO

SUBSURFACE ENGINEERING • OIL PROPERTY MANAGEMENT

P.O. Box 388
GRANVILLE, OHIO
344-6542

1105 GRANVILLE ROAD
NEWARK, OHIO
344-2427

Sec 27

p 219 Elizabeth Twp
Lawrence Co, OH

COMPLETION PROCEDURE

CAMBRIA CLAY # 1-A

2-20-71 Logged with Schlumberger utilizing Compensated Formation Density and Dual Induction Laterolog from 5873' to 5273' (depth of first logging program.)

2-21-71 Ran 5609.27' 4½" OD, 10.5#, K-55, API, smls, R-2, 8 rd thd casing to 5564'. Fitted casing with 6 centralizers and an automatic fillup shoe and float. Cemented with 240 sks Class A cement with 2256# D-53 and 600# D-33; followed top rubber plug with 500 ga. Dowell perforating acid.

3- 5-71 Moved service rig from Hanover to Pedro; unable to move onto location; cat did not meet rig as scheduled.

6-71 Rigged up service machine. Shelwell logged with Gamma Ray, Cement Density Survey and Collar Locator. Perforated at 5447' with a Single Plane Five-Way Jet.

Perforations at 5447' entered the most porous zone of the Copper Ridge and also that zone with the most favorable fluid saturations.

Dowell rigged up to displace that acid spotted during cementing of casing.

Pressured up to 1000 psi and let acid soak with no results. Increased pressure to 1500 psi with no results. Increased pressure incrementally to 2000 psi with slight pressure bleed-off. Permitted acid leak off to decrease pressure to 600 psi; displaced 450 gal. acid at 1000 psi and 0.5 BPM.

Following initial surge of displacement fluid, well flowed at an estimated rate of 15 BPH for three and one half hours. Shut well in over night.

3- 7-71 Flowed well at estimated rate of 15 BPH for six hours with slight gas bubble apparent in displacement fluid.

3- 8-71 Swabbed well to 1000 feet (estimate) with well flowing behind swabbed - show of gas (mostly acid gas) in fluid and behind swab. Continued swabbing - unable to lower fluid below 1000 feet.

3-10-71 Swabbed well to 1000 feet; lost acid gas and natural gas; swabbed salt water; unable to lower fluid below 1000 feet.

3-10-71 Set bridge plug at 5430'.

Perforated at 5373' with a Single Plane Four-Way Jet. These perforations opened the upper portion of the Copper Ridge Dolomite - a section with good porosity, good mud cake and favorable fluid saturations.

3-11-71 Swabbed well to 5300'; well producing some salt water with slight show of gas; able to light gas. Shut in over night.

3-12-71 No pressure build-up over night; fluid level at 3000'. Set bridge plug at 5310'. Perforated 5272' - 5275' with seven jets. These perforations opened the lower Rose Run section as requested by H. Atha.

Swabbed well; unable to lower fluid below 3000'.

3-15-71 Swabbed well; detected some gas in swabbed fluid and in front of swab; unable to lower fluid below 4000'.

Set bridge plug at 5010'; perforated at 4866'. Swabbed well dry.

Perforations at this point (4866') opened the upper portion of the Beekmantown Dolomite where gas was observed on the Baroid Gas Detector. Log analysis indicated fracture systems with little porosity, but slightly less than favorable fluid saturations.

3-[illegible]-71 Checked well for fluid accumulation; swabbed only slight amount of salt water (less than 100 feet); most probably due to pipe runoff.

3-17-71 Shelwell perforated from 4837' to 4866' with 59 jets.

Dowell pumped 1000 gal. 15% H Cl acid at 4866' perforations. Perforations took acid easily at 1000 psi. Acid was displaced at less than 1 BPM at 400 psi (ave).

Swabbed displacing fluid and acid back. Well making gas throughout swabbing operations (est. 40 MCFPD).

-22-71 Checked fluid in hole; found 2700'; swabbed well dry; gas flow estimated at 40 MCFPD.

-24-71 Tried to swab well down; obstruction probably bridge plug at 2800' (floating).

-25-71 Rigged up tools; drove plug to bottom of hole (5010').

-26-71 Set bridge plug at 4986'; fluid level at 2500'; swabbed well down.

-29-71 Checked fluid level at 1500'; swabbed well down; gas estimated at 40 MCFPD.

-30-71 Checked fluid level at 1000'; swabbed well down; gas production estimate at 40 MCFPD.

Dowell pumped 5000 gal. 15% H Cl acid (10 gal. A130 + 10 gal. W-9 +80 gal. L-2) at 400 psi at 4 BPM. ISIP was 300 psi.

71. Swabbed well down; detected slight increase in gas.

31-71 Swabbed well down from fluid level of 1500'.

4- 2-71 Checked fluid level at approximately 1500'. Swabbed well down. Estimated gas at approximately 50 MCFPD.

Remarks: Acid apparently did not stimulate Beekmantown Dolomite as is noted from above results. It is to be noted that acid swabbed back was not spent as well as it should have been.

It is also to be noted that the fluid level after acidization was approximately the same as that recovered during testing of the same horizon.

Apparently, this zone will produce water with gas in some quantities -- whether or not desirable.

There remains the possibility of re-stimulation by fracturing. I suggest we postpone any further stimulation to a later period following some hopeful and successful exploration of the area.

FLUID SAMPLE DATA

S[illegible]ler Pressure __________ P.S.I.G. at Surface
R[illegible]very: Cu. Ft. Gas __________
cc. Oil __________
cc. Water __________
cc. Mud __________
Tot. Liquid cc. __________
Gravity __________ ° API @ __________ °F.
Gas/Oil Ratio __________ cu. ft./bbl.

	RESISTIVITY		CHLORIDE CONTENT
Recovery Water	@	°F.	ppm
Recovery Mud	@	°F.	
Recovery Mud Filtrate	@	°F.	ppm
Mud Pit Sample	@	°F.	
Mud Pit Sample Filtrate	@	°F.	ppm
Mud Weight	8.7	vis 37	cp

Date 2-14-71
Ticket Number 266008-B
Kind of Job STRADDLE OPEN HOLE
Halliburton District WOOSTER
Tester MR. MULLINS MR. BENNETT
Witness MR. VERNEW
Drilling Contractor ATHA DRILLING COMPANY DR

EQUIPMENT & HOLE DATA

Formation Tested Knox
Elevation 725' GL Ft.
Net Productive Interval - Ft.
All Depths Measured From Kelly Bushing
Total Depth 5305' Ft.
Main Hole/Casing Size 7 7/8"
Drill Collar Length 465' I.D. 2.60 Anchor
Drill Pipe Length 4668' I.D. 2.764"
Packer Depth(s) 4700'-4850' Owc - Obk Ft.
Depth Tester Valve 4673' Ft.

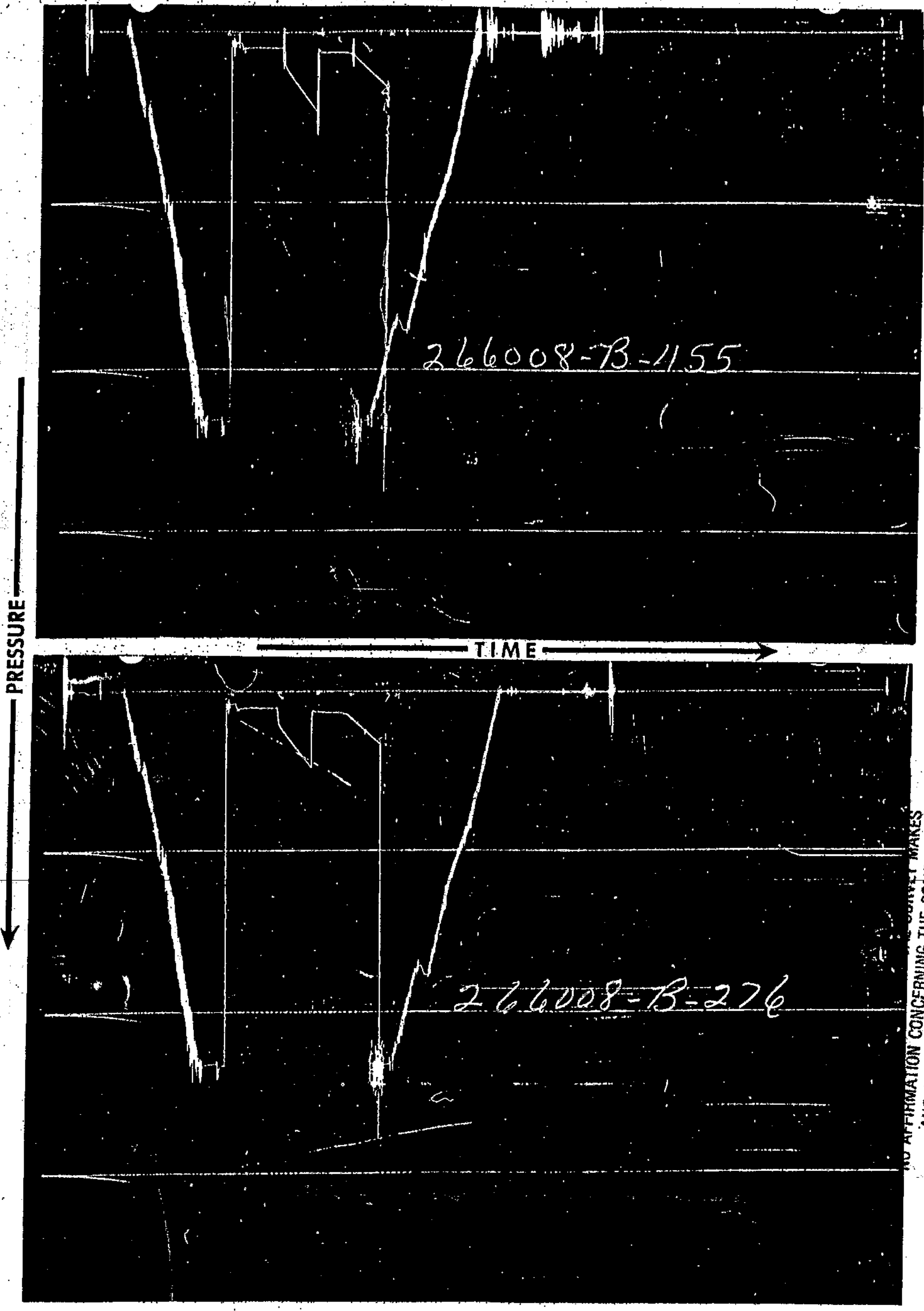
Cushion TYPE AMOUNT Ft.
Depth Back Pres. Valve
Surface Choke 3/8"
Bottom Choke 3/4"

Recovered 250 Feet of gas cut mud
Recovered Feet of
Recovered Feet of
Re[illegible]ed Feet of
Recovered Feet of
Meas. From Tester Valve

Remarks SEE PRODUCTION TEST DATA SHEET

Legal Location Sec. - Twp. - Rng. 27 ELIZABETH
Lease Name
Well No. 1A
Test No. 3
Field Area TRONTON
Tested Interval
County LAWRENCE
State OHIO
Lease Owner/Company Name

TEMPERATURE	Gauge No. 455 Depth: 4675 Ft.		Gauge No. 276 Depth: 4727 Ft.		Gauge No. 260 Depth: 4855' Ft.		TIME	
	12 Hour Clock		12 Hour Clock		Hour Clock		Tool Opened 16:40 A.M. P.M.	
109 °F.	Blanked Off No		Blanked Off Yes		Blanked Off		Tool Closed 17:55 A.M. P.M.	
Actual °F.	Pressures		Pressures		Pressures			
	Field	Office	Field	Office	Field	Office	Reported Minutes	Computed Minutes
Initial Hydrostatic	2317.0	2309	2307.8	2320		2510		
Flow Initial	51.0	60	64.7	80			—	—
Flow Final	81.6	92	107.8	105			45	
Closed In	469.4	470	474.1	478			30	
Flow Initial	102.0	115	118.5	124	HYDROSTATIC		—	—
Flow Final	122.4	127	140.1	143	RELEASE 2329			
Closed In	326.5	327	323.3	334				
Flow Initial								
Flow Final								
Closed In								
Final Hydrostatic	2295.9	2309	2307.8	2320		2510	—	—


266008-B-455
PRESSURE
TIME
266008-B-276

Casing perfs.______ Bottom choke______ Surf. temp.______ °F Ticket No. 266008-B

Gas gravity______ Oil gravity______ GOR______

Spec. gravity______ Chlorides______ ppm Res.______ @______ °F

Date Time a.m. p.m.	Choke Size	Surface Pressure psi	Gas Rate MCF	Liquid Rate BPD	Remarks
16:40	3/8"				Opened tool for first flow with a good blow, off bottom 5 gallon bucket. stayed same throughout rest of flow.
17:25	3/8"				Closed tool for 30 minute first closed in pressure.
17:55	3/8"				Reopened tool for 30 minute first flow with a good blow.
17:60					Gas to surface, but very weak, 5" water on manometer, 3500 cu. ft. in 24 hours.
18:25	3/8"				Closed tool for 30 minute second closed in pressure.
18:55					Off bottom with test tool
					Job over.

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FLUID SAMPLER DATA

ir Pressure ____ P.S.I.G. at Surface
ecovery: Cu. Ft. Gas ____
cc. Oil ____
cc. Water ____
cc. Mud ____
Tot. Liquid cc. ____
avity ____ ° API @ ____ °F.
s/Oil Ratio ____ cu. ft./bbl.

	RESISTIVITY		CHLORIDE CONTENT
covery Water	____ @ ____ °F.		____ ppm
covery Mud	____ @ ____ °F.		
covery Mud Filtrate	____ @ ____ °F.		____ ppm
ud Pit Sample	____ @ ____ °F.		
ud Pit Sample Filtrate	____ @ ____ °F.		____ ppm
ud Weight	8.8	vis 37	cp

Date 2-13-71
Ticket Number 266008 - A
Kind of Job STRADDLE TEST OPEN HOLE
Halliburton District WOOSTER, OHIO
Tester BENNETT
Witness VERNEW
Drilling Contractor ATHA DRILLING COMPANY NM S

EQUIPMENT & HOLE DATA

Formation Tested Knox
Elevation 725' G.L. Ft.
Net Productive Interval ? Ft.
All Depths Measured From Kelly Bushing
Total Depth 5305' Ft.
Main Hole/Casing Size 7 7/8"
Drill Collar Length 421' I.D. 2.50"ANCHOR
Drill Pipe Length 4823' I.D. 2.764"
Packer Depth(s) 4850' - 5000' 66k Ft.
Depth Tester Valve 4828' Ft.

shion TYPE NONE AMOUNT Ft.
Depth Back Pres. Valve NONE
Surface Choke 3/8"
Bottom Choke 3/4"

covered 1000' Feet of gas cut mud
covered 500' Feet of salt water and gas cut mud
covered 1500' Feet of salt water - 9.3#
c d Feet of
covered Feet of

Meo. From Tester Valve

marks SEE PRODUCTION TEST DATA SHEET...

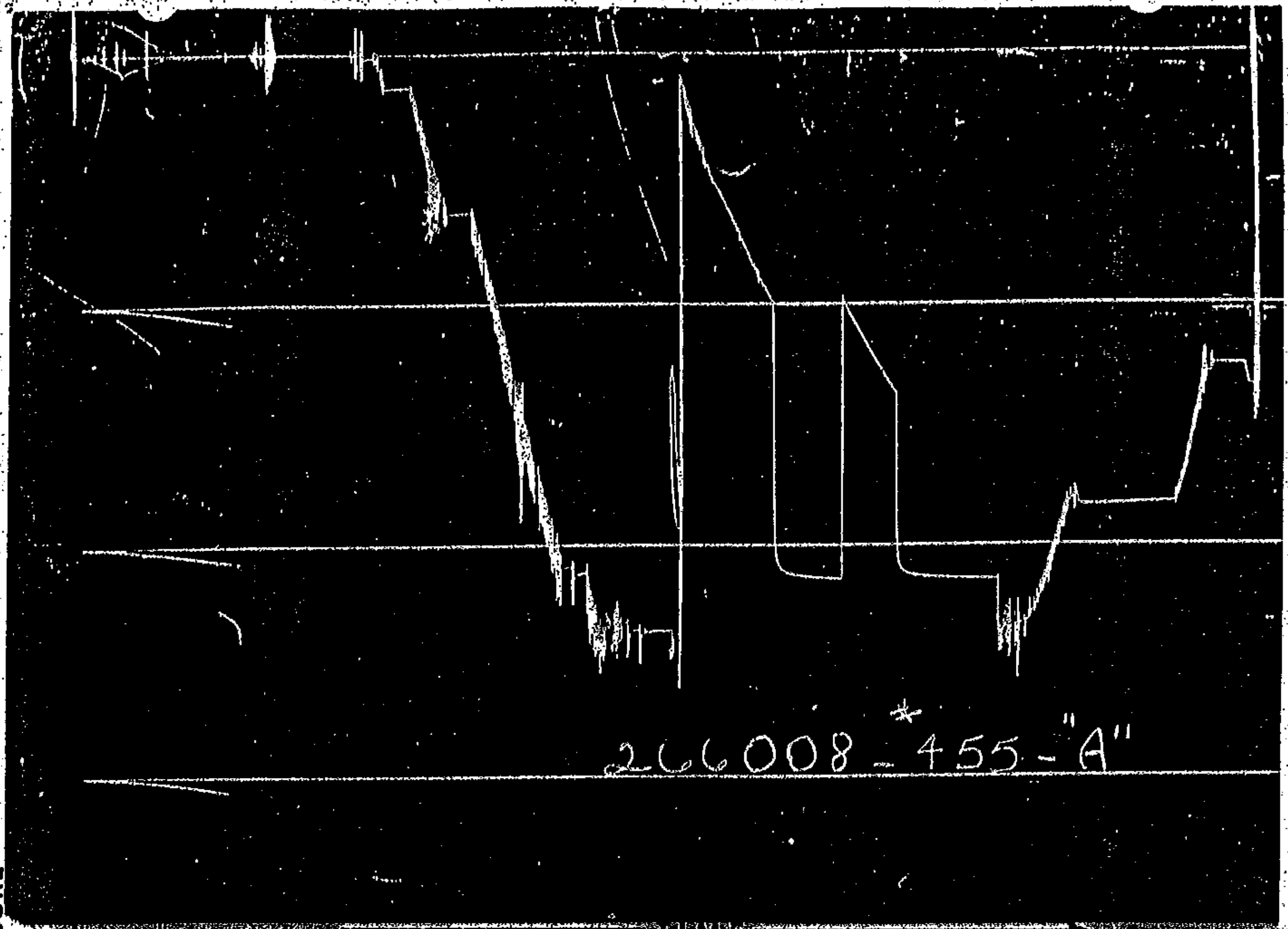
THE DIVISION OF GEOLOGICAL SURVEY MAKES NO AFFIRMATION CONCERNING THE COMPLETENESS AND ACCURACY OF THIS INFORMATION

EMPERATURE	Gauge No. 455 Depth: 4833' Ft.		Gauge No. 276 Depth: 4879' Ft.		Gauge No. 260 Depth: 5004' Ft.		TIME	
	12 Hour Clock		12 Hour Clock		12 Hour Clock		Tool Opened	A.M. 02:45P.M.
109 °F.	Blanked Off NO		Blanked Off YES		Blanked Off YES		Tool Closed	A.M. 05:50P.M.
ual °F.	Pressures		Pressures		Pressures			
	Field	Office	Field	Office	Field	Office	Reported Minutes	Computed Minutes
al Hydrostatic	2359.3	2387	2374.1	2398	-	2462		
Flow Initial	91.8	104	129.3	129	-	-	——	——
Flow Final	1001.0	1001	1004.3	1015	-	-	50	54
Closed In	2147.9	2148	2153.3	2160	-	-	45	40
Flow Initial	970.3	986	982.7	997	-	-	——	——
Flow Final	1363.3	1373	1374.7	1382	-	-	30	32
losed In	2147.9	2150	2153.3	2161	HYDROSTATIC		60	59
Flow Initial						RELEASE: 2288	——	——
Flow Final								
Closed In								
al Hydrostatic	2359.3	2370	2374.1	2383	-	2431	——	——

FORMATION TEST DATA

LITTLE 8 63429 10M 4/69—SS. 34-19

Legal Location Sec. - Twp. - Rng. 27 ELIZABETH
Lease Name
Well No.
Test No.
Field Area TRONTON
Tested Interval
County LAWRENCE
State OHIO
Lease Owner/Company Name



266008 * 455 - "A"

266008 # 276 = "A"

Gauge No. 455 | Depth 4833' | Clock No. 1719 | 12 hour | Ticket No. 266008 - A

	First Flow Period		First Closed In Pressure			Second Flow Period		Second Closed In Pressure			Third Flow Period		Third Closed In Pressure		
	Time Defl. .000"	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.	Time Defl. .000"	PSIG Temp. Corr.	Time Defl. .000"	Log $\frac{t+\theta}{\theta}$	PSIG Temp. Corr.
0	.000	104	.000		1001	.000	986	.000		1373					
1	.0676	345	.0274		2100	.0344	1041	.0410		2123					
2	.1352	522	.0548		2122	.0688	1110	.0820		2133					
3	.2028	664	.0822		2129	.1032	1174	.1230		2137					
4	.2704	818	.1096		2135	.1376	1235	.1640		2141					
5	.365	1001*	.1370		2138	.1720	1294	.2050		2143					
6			.1644		2141	.220	1373**	.2460		2145					
7			.1918		2144			.2870		2146					
8			.2192		2145			.3280		2148					
9			.2466		2147			.3690		2149					
10			.274		2148			.403		2150***					
11															
12															
13															
14															
15															

Gauge No. 276 | Depth 4879' | Clock No. 7521 | hour 12

0	.000	129	.000		1015	.000	997	.000		1382					
1	.0678	359	.0274		2110	.0339	1058	.0411		2135					
2	.1356	529	.0548		2134	.0678	1126	.0822		2146					
3	.2034	674	.0822		2142	.1017	1186	.1233		2151					
4	.2712	830	.1096		2148	.1356	1247	.1644		2155					
5	.366	1015*	.1370		2151	.1695	1307	.2055		2157					
6			.1644		2155	.217	1382**	.2466		2158					
7			.1918		2156			.2877		2159					
8			.2192		2158			.3288		2160					
9			.2466		2159			.3699		2160					
10			.274		2160			.404		2161***					
11															
12															
13															
14															
15															
Reading Interval	10		4			5		6							Minutes

THE DIVISION OF GEOLOGICAL SURVEY MAKES
NO AFFIRMATION CONCERNING THE COMPLETENESS
AND ACCURACY OF THIS INFORMATION.

REMARKS: * INTERVAL = 14 MINUTES. ** INTERVAL = 7 MINUTES. *** INTERVAL = 5 MINUTES.

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SPECIAL PRESSURE DATA

LITTLE'S

Casing perfs. ______ Bottom choke 3/4" Surf. temp 18 °F Ticket No. 266008 - A

Gas gravity ______ Oil gravity ______ GOR ______

Spec. gravity ______ Chlorides ______ ppm Res. ______ @ ______ °F

Date Time a.m. p.m.	Choke Size	Surface Pressure psi	Gas Rate MCF	Liquid Rate BPD	Remarks
02:45	3/8"	NONE			Tool opened on first flow
					Good blow off bottom
					5 gallon bucket - stayed same
					through first flow time
03:35	3/8"	NONE			Closed for first closed in pressure
04:20	3/8"	NONE			Opened to the second flow
					Good blow off bottom
					of 5 gallon bucket
04:25	3/8"	NONE			Gas to the surface but very
					weak - stayed same through
					second flow
04:50	3/8"	NONE			Closed for final closed in
05:50	3/8"	NONE			Off bottom with tools
					Job over
					Bubble hose was trying to freeze off
					on first flow.

PRODUCTION TEST DATA

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APPENDIX C

DRILL STEM AND SWAB TESTS

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APPENDIX C.4

DRILL STEM TEST NO. 4 AND SWAB TEST
UPPER KNOX
4012 FEET TO 4035 FEET

ARISTECH CHEMICAL CORPORATION
TEST/MONITOR WELL
DRILL STEM TEST NO. 4 - FLUID RECOVERY
4/14-18/91

DATE	TIME	ELAPSED TIME (HRS)	TANK GUAGE (INCHES)	TOTAL VOLUME (GALLONS)	INCREMENTAL VOLUME (GALLONS)	VOLUME THIS TEST (GALLONS)
4/14	20:30	PRIOR TO TEST START	10.250	1273.5		0.0
		START TEST				
	23:30	0.00	10.250	1273.5	0.0	0.0
4/15	01:00	0.50	10.250	1273.5	0.0	0.0
	02:00	1.50	10.375	1292.8	19.3	19.3
	03:00	2.50	10.500	1312.0	19.2	38.5
	04:00	3.50	10.625	1331.3	19.3	57.8
	05:00	4.50	10.750	1350.5	19.3	77.0
	06:00	5.50	10.875	1369.8	19.3	96.3
	07:00	6.50	10.875	1369.8	0.0	96.3
	08:00	7.50	11.000	1389.0	19.3	115.5
	09:00	8.50	11.250	1427.5	38.5	154.0
	10:00	9.50	11.375	1446.8	19.3	173.3
	11:00	10.50	11.500	1466.0	19.3	192.5
	12:00	11.50	11.500	1466.0	0.0	192.5
	13:00	12.50	11.500	1466.0	0.0	192.5
	14:00	13.50	11.625	1485.3	19.3	211.8
	15:00	14.50	11.750	1504.5	19.2	231.0
	16:00	15.50	12.000	1543.0	38.5	269.5
	17:00	16.50	12.000	1543.0	0.0	269.5
	18:00	17.50	12.000	1543.0	0.0	269.5
	19:00	18.50	12.000	1543.0	0.0	269.5
	20:00	19.50	12.000	1543.0	0.0	269.5
	21:00	20.50	12.000	1543.0	0.0	269.5
	22:00	21.50	12.000	1543.0	0.0	269.5
	23:00	22.50	12.000	1543.0	0.0	269.5
	24:00	23.50	12.000	1543.0	0.0	269.5
4/16	01:00	24.50	12.000	1543.0	0.0	269.5
	02:00	25.50	12.000	1543.0	0.0	269.5
	03:00	26.50	12.000	1543.0	0.0	269.5
	04:00	27.50	12.000	1543.0	0.0	269.5
	05:00	28.50	12.000	1543.0	0.0	269.5
	06:00	29.50	12.000	1543.0	0.0	269.5

NOTE: 6:00 A.M. GAUGE OF TANK INDICATED 11-7/8" IN TANK
WAIT FOR POOL WELL SERVICE SWAB UNIT
POOL RIGGED UP, DEPTHOMETER INDICATED FLUID LEVEL WAS @ 1611 FT.
WILL RESTART TEST AND LET CUM. FLUID TO DATE MAKE UP PART OF FLUID
LEVEL INCREASE (FOR PURPOSES OF THREE TUBE VOLUMES, NOW = 1216 GAL

DATE	TIME	ELAPSED TIME (HRS)	TANK GUAGE (INCHES)	TOTAL VOLUME (GALLONS)	INCREMENTAL VOLUME (GALLONS)	VOLUME THIS TEST (GALLONS)
	18:00	0.00	12.000	1543.0	0.0	269.5
	18:30	0.50	13.000	1697.0	154.0	423.5
	19:00	1.00	13.250	1735.5	38.5	462.0
	19:20	1.33	13.625	1793.3	57.8	519.8
	19:40	1.67	14.375	1908.8	115.5	635.3
	20:15	2.250	14.625	1947.3	38.5	673.8
	21:00	3.00	14.750	1966.5	19.3	693.0
	22:00	4.00	14.875	1985.8	19.3	712.3

	23:00	5.00	15.000	2005.0	19.3	731.5
4/17	01:00	7.00	15.125	2024.3	19.3	750.8
	03:00	9.00	15.750	2120.5	96.3	847.0
	05:00	11.00	16.000	2158.0	37.5	884.5
	07:00	13.00	16.125	2178.4	20.4	904.9
	08:00	14:00	16.500	2236.5	58.1	963.0
	10:00	16:00	17.000	2314.0	77.5	1040.5
	12:00	18:00	17.000	2314.0	0.0	1040.5
	14:00	20:00	17.000	2314.0	0.0	1040.5
	16:00	22:00	17.250	2352.5	38.5	1079.0
	18:00	24:00	17.625	2410.3	57.8	1136.8
	20:00	26.00	17.625	2410.3	0.0	1136.8
	22:00	28.00	17.750	2429.5	19.3	1156.0
	24:00	30.00	17.875	2448.8	19.3	1175.3
4/18	02:00	32.00	18.000	2468.0	19.3	1194.5
	04:00	34.00	18.250	2506.5	38.5	1233.0

READY FOR COLLECTION OF REPRESENTATIVE SAMPLE
LET WELL RECHARGE UNTIL 08:00, 4/18/91

08:00	38.00	18.250	2506.5	0.0	1233.0
10:00	40.00	18.375	2525.8	19.3	1252.3
11:00	41.00	18.625	2564.3	38.5	1290.8
12:00	42.00	18.875	2602.8	38.5	1329.3
13:00	43.00	19.125	2641.3	38.5	1367.8
14:00	44.00	19.250	2660.5	19.3	1387.1
15:30	45.50	19.500	2699.0	38.5	1425.6

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report is
about 40 pages

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APPENDIX C.5

DRILL STEM TEST NO. 4A
UPPER KNOX
4006 FEET TO 4035 FEET

ENVIROCORP

LEASE : ARISTECH TEST WELL

WELL NO.: 4

TEST NO.: 4-A

TICKET NO. 00873500
25-APR-91
KALKASKA

DST REPORT PRODUCED BY HRS
A DIVISION OF HALLIBURTON COMPANY

ARISTECH TEST WELL
LEASE NAME

4
WELL NO.

4-A
TEST NO.

4006.7 - 4035.0
TESTED INTERVAL

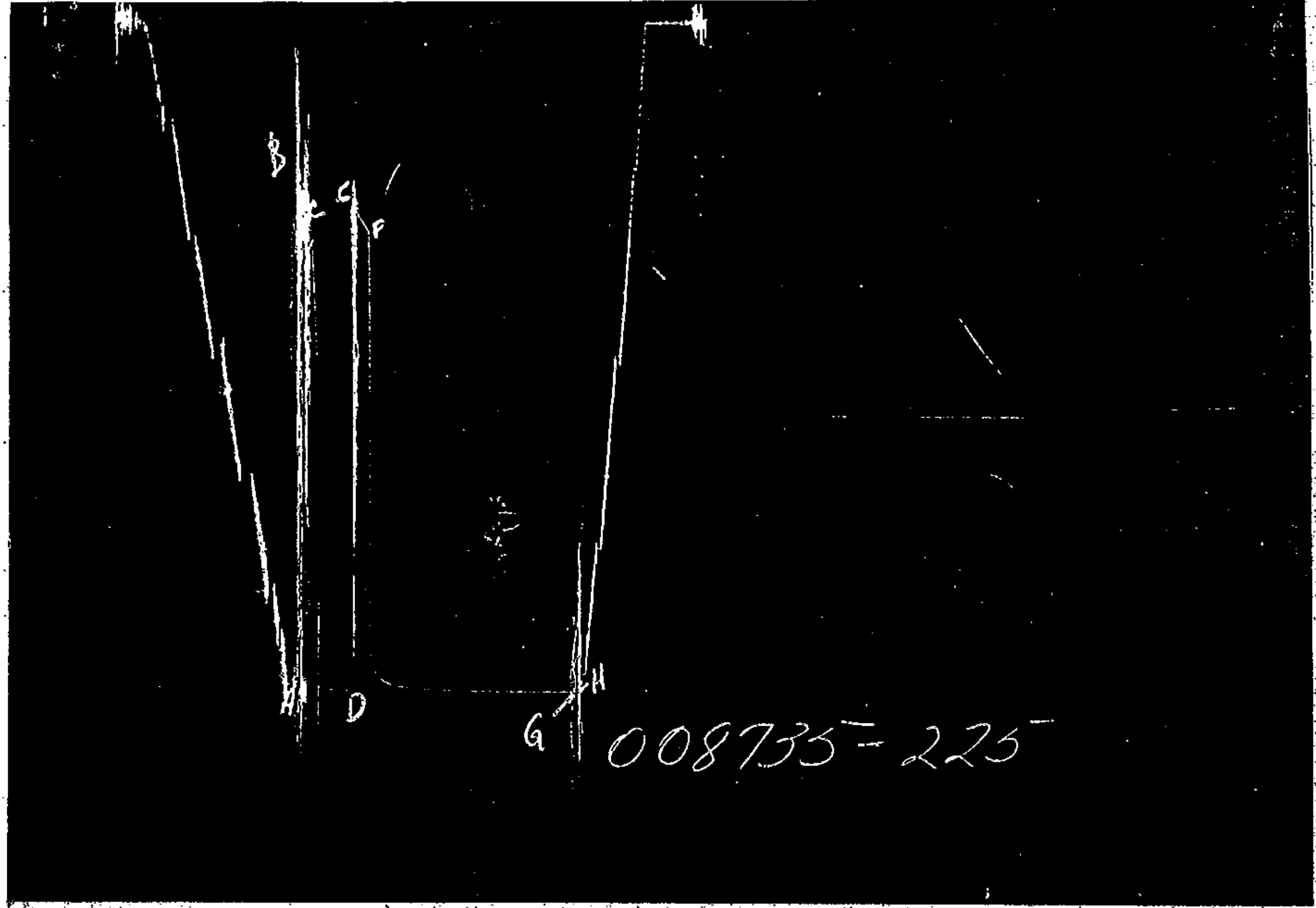
ENVIROCORP
LEASE OWNER/COMPANY NAME

LEGAL LOCATION
SEC. - TWP. - RNG.

FIELD AREA
HAVERHILL

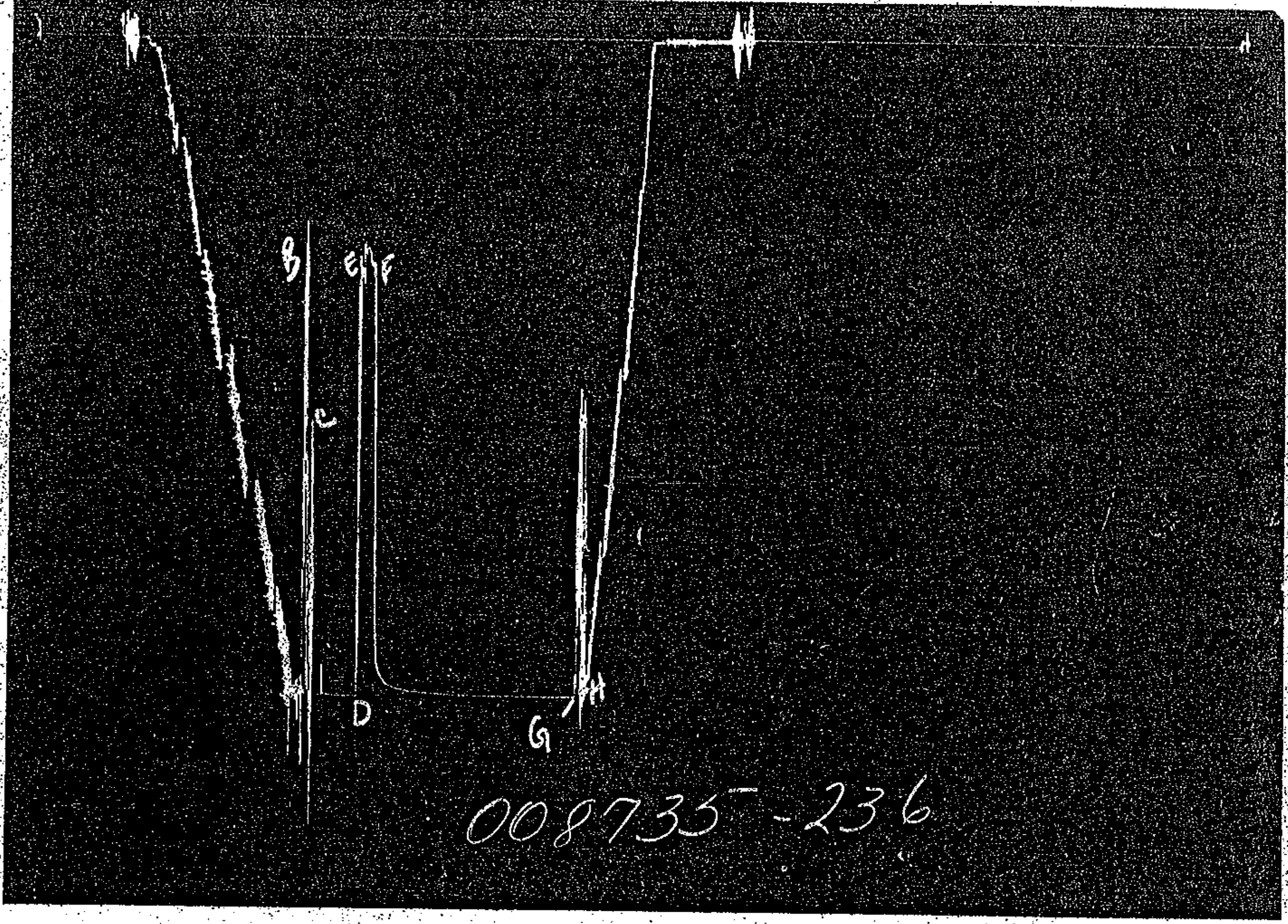
COUNTY
SCIOTO

STATE
OHIO SM



GAUGE NO: 225 DEPTH: 3986.1 BLANKED OFF: NO HOUR OF CLOCK: 72

ID	DESCRIPTION	PRESSURE		TIME		TYPE
		REPORTED	CALCULATED	REPORTED	CALCULATED	
A	INITIAL HYDROSTATIC	1755	1783.6			
B	INITIAL FIRST FLOW	4	461.7	18	32	F
C	FINAL FIRST FLOW		479.5			
C	INITIAL FIRST CLOSED-IN		479.5	159	159	C
D	FINAL FIRST CLOSED-IN	1769	1784.7			
E	INITIAL SECOND FLOW	490	487.7	54	58	F
F	FINAL SECOND FLOW	545	559.5			
F	INITIAL SECOND CLOSED-IN	545	559.5	718	715	C
G	FINAL SECOND CLOSED-IN	1769	1786.7			
H	FINAL HYDROSTATIC	1769	1783.5			



GAUGE NO: 236 DEPTH:4031.8 BLANKED OFF:YES HOUR OF CLOCK: 72

ID	DESCRIPTION	PRESSURE		TIME		TYPE
		REPORTED	CALCULATED	REPORTED	CALCULATED	
A	INITIAL HYDROSTATIC	1771	1790.8			
B	INITIAL FIRST FLOW		628.0	18	32	F
C	FINAL FIRST FLOW		1049.1			
C	INITIAL FIRST CLOSED-IN		1049.1	159	159	C
D	FINAL FIRST CLOSED-IN	1798	1815.1			
E	INITIAL SECOND FLOW		664.8	54	58	F
F	FINAL SECOND FLOW		617.1			
F	INITIAL SECOND CLOSED-IN		617.1	718	715	C
G	FINAL SECOND CLOSED-IN	1805	1812.8			
H	FINAL HYDROSTATIC	1805	1790.4			

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Report is about
80 pages

002636
Box 34

APPENDIX C.7

DRILL STEM TEST NO. 6 AND SWAB TEST
LOWER KNOX
4446.7 FEET TO 4480 FEET

ARISTECH CHEMICAL CORPORATION
TEST/MONITOR WELL
DRILL STEM TEST NO. 6 - FLUID RECOVERY
5/09/91

DATE	TIME (HRS)	ELAPSED TIME (HRS)	TANK GAUGE (INCHES)	TOTAL VOLUME (GALLONS)	INCREMENTAL VOLUME (GALLONS)	VOLUME THIS TEST (GALLONS)
5/09	08:00	PRIOR TO TEST START START TEST	34.250	4970.5	0.0	0.0
	09:30	1.50	34.750	5047.5	77.0	77.0
	10:00	2.00	38.000	5551.0	503.5	580.5
	10:30	2.50	40.000	5871.0	320.0	900.5
	11:00	3.00	42.750	6328.0	457.0	1357.5
	11:30	3.50	45.500	6803.0	475.0	1832.5
	12:00	4.00	49.000	7419.0	616.0	2448.5
Stop swabbing continuously, have achieved three tubing volumes.						
	13:30	5.50	49.500	7507.0	88.0	2536.5
	15:00	7.00	50.000	7595.0	88.0	2624.5
	16:00	8.00	50.750	7670.5	75.5	2700.0
	16:30	8.50	52.000	7946.0	275.5	2975.5
	17:00	9.00	53.000	8122.0	176.0	3151.5
Begin sampling at 19:00. Dave Evans with OEPA on location to observe.						
	19:00	11.00	55.500	8562.0	440.0	3591.5
	20:00	12.00	58.000	9001.0	439.0	4030.5
	21:00	13.00	63.000	9881.0	880.0	4910.5
	22:00	14.00	68.000	10760.0	879.0	5789.5
	23:00	15.00	68.250	10804.5	44.5	5834.0

Finish sampling at 22:30.

ARISTECH TEST WELL
DST NO.6 - LOWER KNOX (4447 FT. - 4480 FT.)
FLUID LEVEL AND "TUBING VOLUME" DETERMINATION
May 9, 1991

TEST INTERVAL - 4480 FT. - 4447 FT., 33.0 FT.
TOTAL VOLUME OF 4" HOLE = .6528 GAL./FT.
VOLUME BELOW PACKER = 21.54 GALLONS

*DUE TO THE FLUID INFLUX AND RECHARGING CAPABILITY OF THIS TEST ZONE, THREE TUBING VOLUMES WERE CALCULATED USING THE ENTIRE TUBING STRING.

TUBING VOLUME IS .1624 GAL./FT., PACKER IS SET AT 4447 FT.
THUS, ONE "TUBING VOLUME" = .1624 * (4447 FT)
ONE "TUBE VOLUME" = 722 GALLONS
SYSTEM VOLUME = 744 GALLONS

THREE TUBING VOLUMES = 2231 GALLONS

ARISTECH CHEMICAL % ENVIROCORP

LEASE : TEST WELL

WELL NO.: 4

TEST NO.: 6

DRILL STEM TEST REPORT

HALLIBURTON RESERVOIR SERVICES

A Halliburton Company

TEST WELL
LEASE NAME

4
WELL NO.

6
TEST NO.

4446.7 - 4480.0
TESTED INTERVAL

ARISTECH CHEMICAL % ENVIROCORP
LEASE OWNER/COMPANY NAME

NOMENCLATURE

B = Formation Volume Factor (Res Vol/Std Vol)

c = System Total Compressibility (Vol/Vol)/psi

DR = Damage Ratio

h = Estimated Net Pay Thickness Ft

k = Permeability md

m { = (Liquid) Slope Extrapolated Pressure Plot psi/cycle
  { = (Gas) Slope Extrapolated m(P) Plot MM psi²/cp/cycle

$m(P^*)$ = Real Gas Potential at P^* MM psi²/cp

$m(P_f)$ = Real Gas Potential at P_f MM psi²/cp

AOF_1 = Maximum Indicated Absolute Open Flow at Test Conditions MCFD

AOF_2 = Minimum Indicated Absolute Open Flow at Test Conditions MCFD

P^* = Extrapolated Static Pressure Psig

P_f = Final Flow Pressure Psig

Q = Liquid Production Rate During Test BPD

Q_1 = Theoretical Liquid Production w/Damage Removed BPD

Q_g = Measured Gas Production Rate MCFD

r_i = Approximate Radius of Investigation Ft

r_w = Radius of Well Bore Ft

S = Skin Factor

t = Total Flow Time Previous to Closed-in Minutes

Δt = Closed-in Time at Data Point Minutes

T = Temperature Rankine °R

φ = Porosity (fraction)

μ = Viscosity of Gas or Liquid cp

Log = Common Log

ARISTECH CHEMICAL % ENVIROCORP

LEASE : TEST WELL

WELL NO.: 4

TEST NO.: 6

TICKET NO. 00783100
20-MAY-91
KALKASKA

TEST WELL
LEASE NAME

4
WELL NO.

6
TEST NO.

4446.7 - 4480.0
TESTED INTERVAL

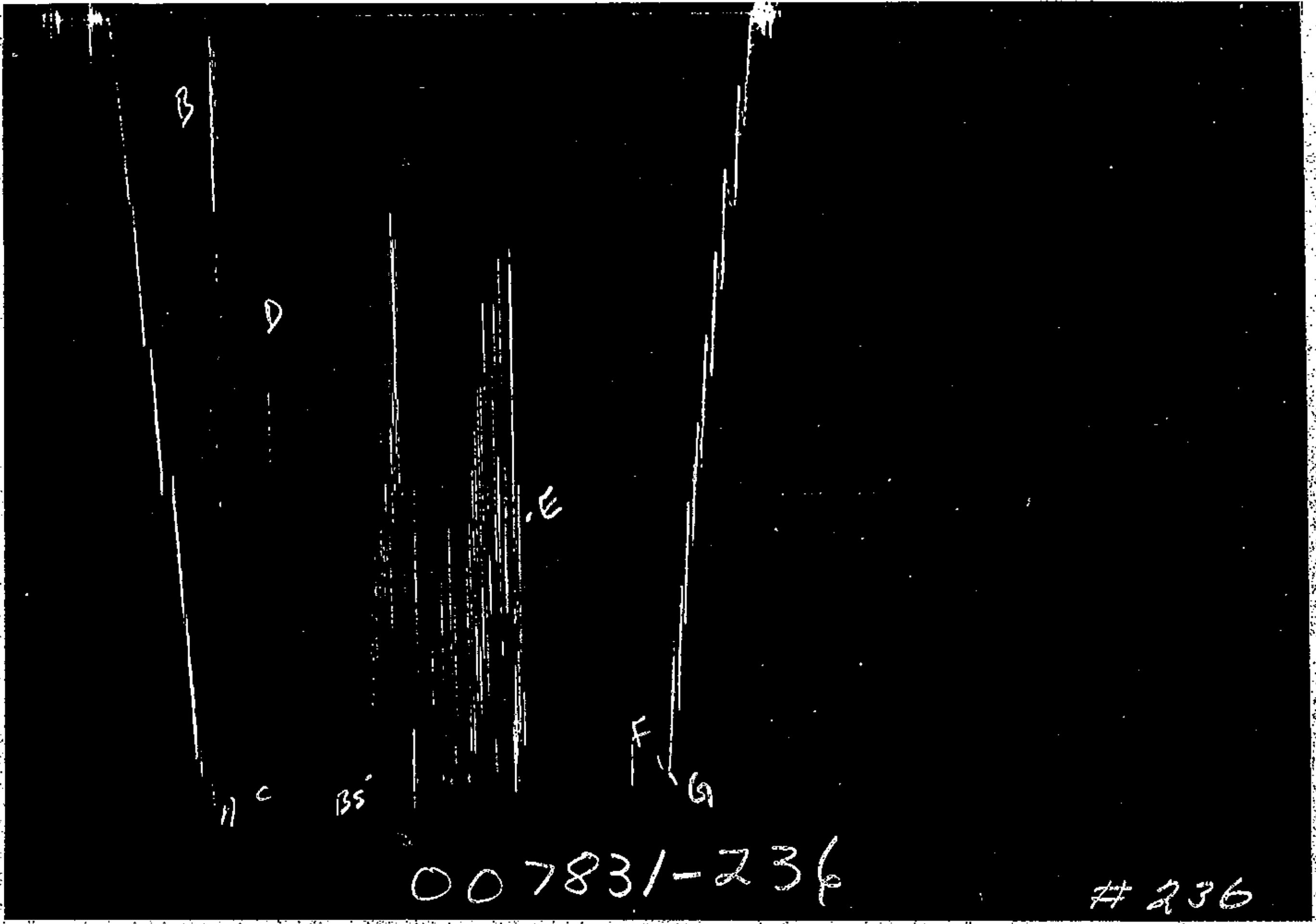
ARISTECH CHEMICAL % ENVIR
LEASE OWNER/COMPANY NAME

ATION
P. - RNG.
ARISTECH PLANT

FIELD
AREA
HAVERHILL

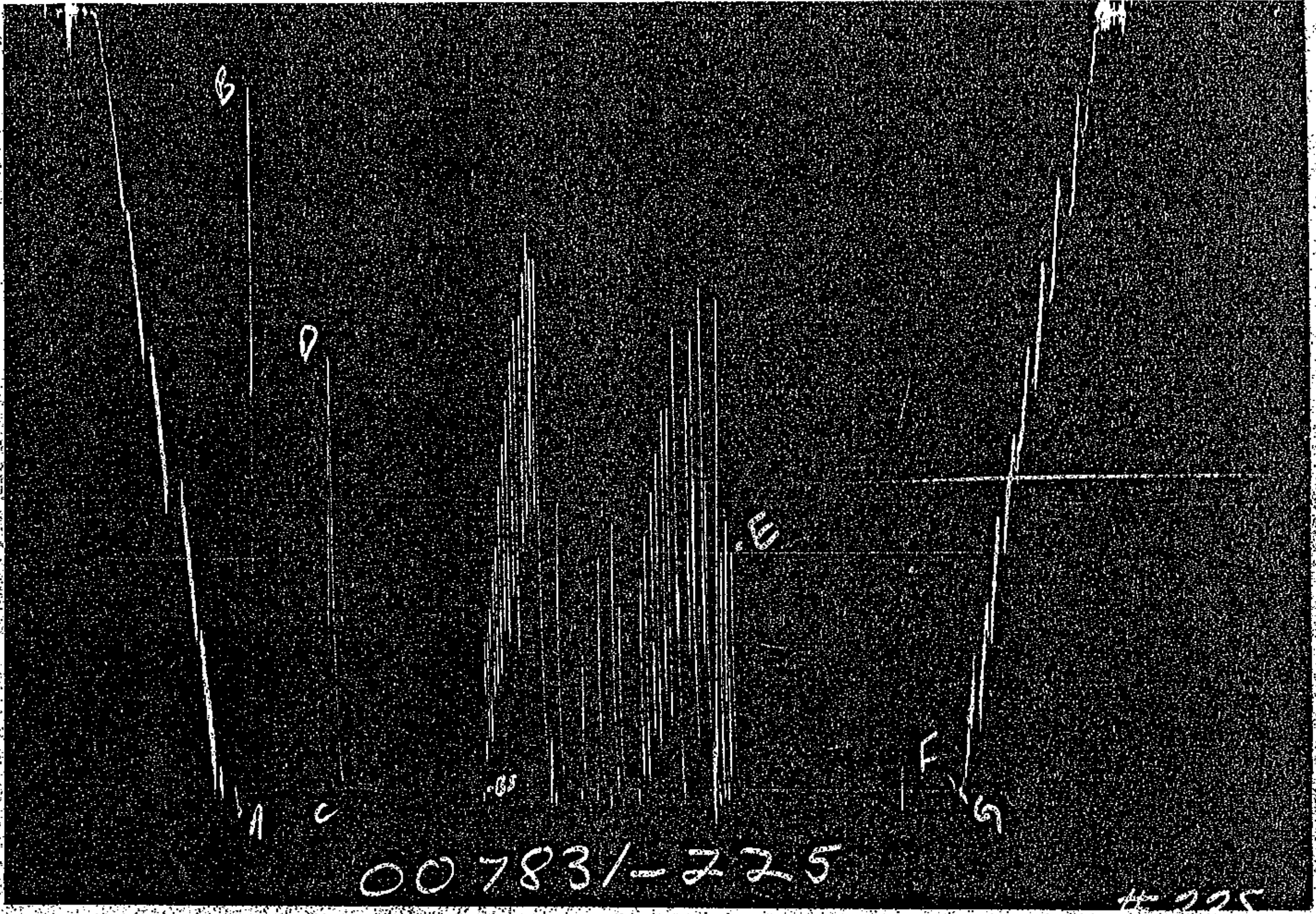
COUNTY
SCIOTO

STATE
OHIO



GAUGE NO: 236 DEPTH: 4427.8 BLANKED OFF: NO HOUR OF CLOCK: 120

ID	DESCRIPTION	PRESSURE		TIME		TYPE
		REPORTED	CALCULATED	REPORTED	CALCULATED	
A	INITIAL HYDROSTATIC	2118	2116.9			
B	START OF BUILDUP	25	118.1	283	272	C
C	END OF BUILDUP	2061	2058.4			
D	INITIAL FIRST FLOW	870	862.6	1446	1405	F
E	FINAL FIRST FLOW	2061	1372.2			
E	INITIAL SECOND CLOSED-IN	2061	1372.2	734	786	C
F	FINAL SECOND CLOSED-IN	2061	2060.4			
G	FINAL HYDROSTATIC	2063	2060.4			



GAUGE NO: 225 DEPTH: 4477.0 BLANKED OFF: YES HOUR OF CLOCK: 72

ID	DESCRIPTION	PRESSURE		TIME		TYPE
		REPORTED	CALCULATED	REPORTED	CALCULATED	
A	INITIAL HYDROSTATIC	2140	2139.0			
B	START OF BUILDUP	206	205.6	283	272	C
C	END OF BUILDUP	2085	2083.6			
D	INITIAL FIRST FLOW	916	914.1	1446	1405	F
E	FINAL FIRST FLOW	2081	1437.5			
E	INITIAL SECOND CLOSED-IN	2081	1437.5	734	786	C
F	FINAL SECOND CLOSED-IN	2082	2080.3			
G	FINAL HYDROSTATIC	2082	2081.0			

Appendix C

List of wells in the AOR with RHOB, porosity and permeability calculations for injection intervals

APPENDIX C

Aristech
well number 1
Scioto County, OH
Green Township
Permit no. 20212
DGS Core No. 2958 data sheets building I P8-68 002630 (see APPENDIX E this report)

Depth (ft)	Kmax(md)	Perm K-90(md) vertical perm (md)	Vertical (md)	Porosity	Grain density (	FM
4242-4246.5	0	0	NA	3.9	2.63	RSRN
4250-4261.2	83	33	NA	10.4	2.61	RSRN
5532-5561	94	26.8	NA	11.9	2.55	MRVL
5563-5573	3.9	0.4	NA	3.9	NA	MRVL

Aristech
Monitor well
Scioto County, OH
Green Township
Permit no. 60141
DGS Core No. 3409 data sheets building I P2-91 002637 (see APPENDIX E this report)

Depth (ft)	Kmax(md)	Perm K-90(md) vertical perm (md)	Vertical (md)	Porosity	Grain density (	FM
4021-22	231	0.02	0.02	2.2	2.79	BKMN
4193-94	6	3.3	0.07	9.1	2.65	RSRN
4202-03	86	70	1.4	12.7	2.64	RSRN
4592.5-93.1	0.1	0.06	<.01	2.7	2.73	CPRG
5196.5-97.0	1.8	0.04	1.7	3.6	2.84	CPRG

Aristech
well number 3
Scioto County, OH
Green Township
Permit no. 60033
DGS Core No. 3248 data sheets building I P1-90 002632 (see APPENDIX E this report)

APPENDIX C

Nu Corp. Energy Company
#1 Trepanier
Jackson County, OH
Franklin Township
Section 8
Permit No. 102
OGS Core No. 2898
Source: Core Laboratories, Inc.; Note: Depths annotated on cores are 10 ft deeper than those on core descriptions.

		Perm. To Air MD			Porosity	Fluid Sats.				
Samp No.	Depth	Max.	90 deg.	Vert.	Gex. Fld.	Oil	Water	Gr. Den.	Description	FM
1	4498-99	0.1	0.1	0.1	1.5	0	94.7	2.77	DOL,SDY,SL/SHY,FOSS	RSRN
2	4499-00	3	2.5	0.2	3.1	0	56.5	2.68	SD,SL/SHY	RSRN
3	4500-01	17	17	0.9	7.8	0	24.8	2.67	SD,SL/SHY	RSRN
4	4501-02	33	32	1.9	9.6	0	62.3	2.64	SD,SL/SHY	RSRN
5	4502-03	26	26	14	11.5	0	89.5	2.65	SD,SL/SHY	RSRN
6	4503-04	156	152	11	12.8	0	94	2.63	SD,SL/SHY	RSRN
7	4504-05	60	17	1.2	10.4	0	82.8	2.62	SD,SL/SHY	RSRN
8	4505-06	17	15	0.6	8.6	0	71.3	2.64	SD,SL/SHY	RSRN
9	4506-07	6.3	5.8	0.5	8.4	0	71.1	2.64	SD,SL/SHY	RSRN
10	4507-08	6.7	6.6	1	9.1	0	72.9	2.66	SD,SL/SHY	RSRN
11	4508-09	3.5	3.4	0.6	7.7	0	73.4	2.64	SD,SL/SHY	RSRN
12	4509-10	0.3	0.2	0.1	5.2	0	85.4	2.63	SD,SL/SHY,STY	RSRN
13	4510-11	0.1	0.1	0.1	2.9	0	85.3	2.7	SD,SL/SHY	RSRN
14	4511-12	0.1	0.1	0.5	5.3	0	77.3	2.68	SD,SL/SHY	RSRN
15	4512-13	0.2	0.1	0.3	5.6	0	75	2.68	SD,SL/SHY	RSRN
16	4513-14	8.6	7	2	8	0	75.8	2.67	SD	RSRN
17	4514-15	8.1	7.3	0.4	7.3	0	76.9	2.66	SD	RSRN
18	4515-16	3.5	3.4	0.5	9.5	0	79.5	2.68	SD,SL/SHY	RSRN
19	4516-17	0.9	0.8	0.1	9	0	86	2.65	SD,SL/SHY	RSRN
20	4517-18	20	16	0.2	11.6	0	79.1	2.64	SD,SL/SHY	RSRN
21	4518-19	18	16	1.7	12.5	0	84.7	2.68	SD	RSRN
22	4519-20	159	144	35	14.9	0	73.1	2.68	SD	RSRN
23	4520-21	28	26	46	10.8	0	90.7	2.68	SD	RSRN
24	4521-22	63	59	41	13.2	0	86	2.68	SD,SL/SHY	RSRN
25	4522-23	71	70	27	13.6	0	80.9	2.68	SD,SL/SHY	RSRN

26	4523-24	198	194	98	14.8	0	89.3	2.68	SD,SL/SHY	RSRN
27	4524-25	20	19	0.1	9.9	0	72	2.68	SD,SL/SHY	RSRN
28	4525-26	184	152	22	13.2	0	95.3	2.67	SD,SL/SHY	RSRN
29	4526-27	178	159	51	13	0	98.8	2.68	SD	RSRN
30	4527-28	180	162	76	13.1	0	98.1	2.68	SD,SL/SHY	RSRN
31	4528-29	109	103	41	12.1	0	97.8	2.68	SD,SL/SHY	RSRN
32	4529-30	11	3.4	0.7	7	0	69.6	2.67	SD,SL/SHY	RSRN
33	4530-31	0.1	0.1	0.1	4.3	0	75.6	2.68	SD,SL/SHY	RSRN
34	4531-32	0.2	0.1	0.1	2	0	75	2.67	SD	RSRN

APPENDIX C

Hope Natural Gas
No. 9634 Power Oil Company
Wood County, WV
Permit No. 351
DGS Core No. 768
Source: 1959, West Virginia Geological Survey, Investigations No. 18, p. 126,127.
Interval: Wells Creek-Rome

Depth	Density	Porosity	Thermal Cond.	Dielectric Constant	Magnetic Suscep.	Young's Modulus	Rigidity Modulus	Poisson's Ratio	Longit. Internal Friction	Shear Internal Friction	FM
10670	2.79		9.3	32	5						WLCK
10692	2.665	0.7	13.2	8.1							WLCK
10710	2839	0.14	11.1	9.1							BKMN
10730					6						BKMN
10750	2.749	0.5	10.8	8.5							BKMN
10771	2.771	0.2	12	8.2							BKMN
10791	2.813	0.45	12.2	7.7							BKMN
10831											BKMN
10851	2.783	0.15	9.7	11.5	1	9.5	3.75	0.26	0.019	0.008	BKMN
10871	2.832	0.2	11.7	9.6	3	8.65	3.64	0.19	0.023	0.014	BKMN
10891	2.817	0.1	11.5	8.1	1						BKMN
10911	2.797	0.45	10.4	12.9	2	8.55	2.95	0.44	0.04	0.04	BKMN
10931	2.836	0.35	12.6	7.8	2						BKMN
10951	2.804	0.45	10.6	8.6	4						BKMN
10971	2.811	0.25	11.3		4	7.5	3.45	0.11	0.026	0.023	BKMN
10991	2.813	0.35	11.1	8.6	2	6.9	3.05	0.13	0.024	0.027	BKMN
11011	2.841	0.2	11.8	7.7							BKMN
11031	2.815	0.4	11.4	5.9		6.15	2.8	0.1	0.023	0.057	BKMN
11050	2.835	0.25	11.7	7.4	1						BKMN
11070	2.827	0.25	12.2	7.1	2	5.95	2.75	0.09	0.038	0.025	BKMN
11090	2.824	0.45	13.2	10.5	1						BKMN
11101	2.825	0.4	13.2	10	1	7.45	3.25	0.14	0.032	0.029	BKMN
11130	2.819	0.2	13.7	8.6	1	4.25	2.3	-0.09	0.068	0.043	BKMN
11150	2.818	0.35	12.6	8.4	1						BKMN
11170	2.756	0.15	11.2	7.4	1	8.55	3.7	0.16	0.031	0.015	BKMN
11190	2.797	0.3	11.6	7.7	1	3.05	2.1	-0.27	0.022	0.038	BKMN

11211	2.79	0.6	12.1	9.3	1						BKMN
11230	2.814	0.4	11.6	10	2	3.55	2.2	-0.21	0.114	0.038	BKMN
11251	2.819	0.45	12.1	8.9	1	4.45	2.35	-0.06	0.065	0.031	BKMN
11267	2.819	0.3	11.5	8.1	1						BKMN
11291	2.817	0.45	11.9	9.6	1						BKMN
11330	2.676	0.55	9.7	11.1	1						BKMN
11349	2.805	0.65	11.6	7.5	1						BKMN
11371	2.825	0.35	11.6	8.5	3						BKMN
11391	2.792	1.05	11.2	7.6	1	6.6	2.9	0.13	0.078	0.044	BKMN
11410	2.815	0.45	12.2	8		6.85	2.9	0.18	0.036	0.041	BKMN
11431	2.816	0.45	11.8	9.7	2						BKMN
11450	2.813	0.2	11.3	7.7		6.45	2.9	0.12	0.03	0.02	BKMN
11470	2.835	0.45	11.2	7.4							BKMN
11491	2.803	0.4	12.2	9.2							BKMN
11510	2.799	0.35	10.1	8.2	2						BKMN
11531	2.825	0.25	11.9	8.1							BKMN
11551	2.819	0.45	13.1	8.4							BKMN
11571	2.824	0.3	12.2	8.4	2						BKMN
11591	2.821	0.3	12.4	9.1							BKMN
11611	2.806	0.3	11	10.1							BKMN
11631	2.813	0.4	11.8	8							BKMN
11650	2.651	0.45	14.7	4.6		2.95	1.85	-0.2	0.112	0.041	RSRN
11671	2.729	0.45	14	6.8		3.3	2	-0.16	0.095	0.055	RSRN
11684	2.63	0.5	15.2	4.5		4.35	2.45	-0.11	0.025	0.031	RSRN
11924	2.824	0.75	12.4	5.6		7.2	3.05	0.19	0.074	0.067	CPRG
11945	2.819	0.3	13.4	8.6	1						CPRG
13005	2.819	0.25	9.2	7.8	4						MRVL
13026	2.678	0.65	10	6.2	6						MRVL
13045	2.832	0.2	10.4	7.6	8	7.1	2.95	0.19	0.024	0.01	MRVL
13066	2.663	0.6	13.7	5.7	2						MRVL
13086	2.66	0.7	12.6	5.2	6						MRVL
13106	2.515	2.5	13.5	4.5	1						MRVL
13126	2.683	0.6	7	7	8						MRVL
13146	2.799	0.35	8	8.6	10	5.25	2.5	0.05	0.028	0.01	MRVL
13165	2.675	0.85	7.4	6.9							MRVL
13314	2.91	0.35	5	43.5	57						PCMB
13318	2.65	0.2	7.9	9.3	8						PCMB

Appendix D

Additional references

APPENDIX D. ADDITIONAL REFERENCES

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Appendix E

Tests and analyses from Aristech Class 1 well site, Scioto County, Ohio

Summary of Aristech Class I Storage Materials

APPENDIX E CLASS
1 DATA/REPORTS

Cited this report	Location	Bar Code Building I	Box No.	Dates	Company	General Report Contents	Description
	Building I	002630	28	12/20/67-4/1/88	Aristech	Report P8-68	Table 3 Fluid Mobilities through core samples of MNSM, well # 1.
YES	Building I	002630	28			Report P8-68	Table 1 Core Analysis, well #.1: Berea; Newburg; St. Peter; Rose Run; Mt Simon (Maryville "lower unit").
	Building I	002630	28			Report P8-68	Figure 3 Pressure Transient tests, MNSM, well # 1.
	Building I	002630	28			Report P2-88	Annulus pressure test, well #1 & #2.pages 86-88
	Building I	002632	30	1/29/90-5/1/90	Aristech	Report P1-90	Appendix I:Chemical analyses formation fluids: BERE, CNSG/ROME, MNSM, RSRN, SNPR, well # 3.
YES	Building I	002632	30			Report P1-90	Core analysis and results for permeability and porosity, well # 3.
YES	Building I	002633	31	5/1/90-5/31/90	Aristech	Report P2-90	Appendix 4.3-H: Core Analysis, well # 3.
	Building I	002633	31			Report P2-90	Appendix 5.3-C: Chemical Analysis, BERE sample in Scioto County brine well.
	Building I	002636	34	4/6/91-7/12/91	Aristech	Report P1-91 vol. 4	Appendix 9.1-A Interference Test analysis.
	Building I	002636	34			Report P1-91 vol. 4	page 9-2 Step-rate test analysis.
	Building I	002636	34			Report P1-91 vol. 4	page 9-2: In-situ stress test.
	Building I	002636	34			Report P1-91 vol. 4	Appendix 9.0-A: about 200 pages; Pressure fall-off, step rate and Interference tests for WDW 1,2, & 3.
	Building I	002636	34			Report P1-91 vol. 4	Appendix 7.3-B; Chemical analysis of samples of BERE and LOGN, well # 4.
	Building I	002636	34			Report P1-91 vol. 4	Appendix 7.3-C; Chemical analyses of water samples, well # 3.
	Building I	002636	34			Report P1-91 vol. 4	Appendix 7.3-D Chemical analysis of formation samples in Scioto County brine wells.
	Building I	002636	34			Report P2-91	Appendix C.1 to C.7; DRILL STEM and SWAB tests.
YES	Building I	002636	34			Report P1-91 vol. 4	Appendix 6.3-LPetrographic study of core interval 5915'-6109' (MNSM), Maryville this report, well # 3.
	Building I	002637	35	7/12/91-8/15/91	Aristech	Report P4-91	Appendix I: Description of Formation Testing Procedures. Well #3
	Building I	002637	35			Report P4-91	Appendix G-2: Summary off Formation Testing and Logging Procedures. Well #3
	Building I	002637	35			Report P4-91	Appendix G-3: Summary off Formation Testing and Logging Procedures. Well #4
	Building I	002637	35			Report P2-91	Appendix G IN-SITU stress test.
YES	Building I	002637	35			Report P2-91	Appendix H: Petrographic core analysis, well # 4, Samples from BKMN, RSRN, CPRG, ROME (Maryville this report)
	Building I	002637	35			Report P4-91	Appendix G-4: Step-rate testing, well # 3
	Building I	002637	35			Report P3-91	Tables 1 through 5: In-Situ stress test data.
	Building I	002637	35			Report P3-91	Rose Run/ Copper Ridge Rpeort V 1 sections 3 & 5 analyses and data weels 1, 2, 3, 4
	Building I	002639		8/15/91-8/31/91	Aristech	Report P4-91	Appendix S-1: In-Situ Stress Measurements.
	Building I	002639				Report P4-91	Appendix AA DST Data Analysis.
	Building I	002639				Report P4-91	Appendix BB: Summary of Studies Performed and Methodologies.
	Building I	002639				Report P4-91	Appendix M: Assessment of Haverhill Fluid Chemistry.
	Building I	002640		5/12/68-1/1/96	Aristech	Report W1-68	Inter-office memorandum well 1 june 15, 1968

note: P#-## stands for Permit - Volume Number - Year

p8-68
002630
Box 28
OGS CORE # 2958

TABLE 3

USS CHEMICALS
COMPARISON OF FLUID MOBILITIES THROUGH CORE SAMPLES OF MT. SIMON SANDSTONE HAVERHILL, WASTE DISPOSAL WELL

Core Sample No.	Depth, K.B.	% Por	Perm to Air Md.	Fluid Mobility Ratios Compared to Mt. Simon Brine 1/			
				Fresh Water	Mt. Simon Brine	Filtered Phenol Waste	
						9.7 pH	6.4 pH
1	5540	13.7	55	2.06	1.00	1.22	
2	5544	13.7	30	3.26	1.00	1.27	
71X	5545	15.3	41		1.00		1.43
3	5547	15.6	22	3.14	1.00	1.29	
75X	5549	14.1	41		1.00		1.47
76X	5550	15.5	50		1.00		1.56
4	5552	14.7	10	4.46	1.00	1.37	
82X	5556	16.2	26		1.00		1.82
Avg 9.7 pH waste		14.4	29	2.58	1.00	1.26	
Avg 6.4 pH waste		15.3	40		1.00		1.47

1/ "Mobility" of a fluid is defined as the permeability of that fluid divided by the viscosity of the fluid. The mobility ratio is the ratio of the respective mobilities of the two fluids. (See pages 4 and 5 for discussion.)

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P 8-68
002630
Box 28
CITED
DGS CORE #2958

TABLE 1

USS CHEMICALS
HAVERHILL DISPOSAL WELL NO. 1
SCIOTO COUNTY, OHIO

SUMMARY OF CORE ANALYSES

Core No.	Formation	Depth, Feet From	Depth, Feet To	Feet Analyzed	Avg Perm Md	Average Porosity Per Cent	Average Grain Density	Average Bulk Density	% Soluble in 15% HCl
1	Berea SS	710	733.0	23.	1.5	12.1	2.66	2.34	
2	Newburg Ls, plug	1805	1834.5	11.	4.2	2.1	2.79	2.73	
	Newburg Ls, whole core	1805	1833.0	5.	--	5.9	2.82	2.63	96
3	St. Peter Dolo	3979	4007.0	6.	-0-	2.5	2.74	2.67	
4	Rose Run SS	4242	4246.5	4.5	-0-	3.9	2.63	2.52	
5	Rose Run SS	4250	4261.8	11.	33.	10.4	2.61	2.34	
6	Mt. Simon SS	5532	5561.0	29.	26.8	11.9	2.55	2.26	
7	Mt. Simon SS, shaly	5563	5573.0	10.	0.4	3.9			
8	Granite	5595	5617.0	Not Analyzed, Dense.					

10-18-68 mk

TABLE 2

EARLOUGHER ENGINEERING

RESULTS OF CORE ANALYSES

COMPANY USS Chemicals

WELL Haverhill Disposal Well No. 1

Sample No.	Depth Feet	Air Perm. Md.	Porosity Per Cent		Calc Grain Density	Meas Bulk Density		Remarks
	BEREA SAND	CORE NO. 1 (710-733 FEET)						
1	710.0	2.2	12.2		2.70	2.37		Sand
2	711.0	3.4	13.8		2.64	2.27		Sand
3	712.0	2.5	13.4		2.64	2.29		Sand
4	713.0	2.2	14.1		2.69	2.31		Sand
5	714.0	1.9	13.8		2.67	2.31		Sand
6	715.0	4.0	14.3		2.66	2.28		Sand
7	716.0	1.3	13.3		2.69	2.33		Sand
8	717.0	3.7	14.4		2.64	2.26		Sand
9	718.0	1.3	13.8		2.68	2.31		Sand
10	719.0	0.4	12.5		2.62	2.29		Sand
11	720.0	-0-	5.0		2.58	2.45		Dense muddy sand
12	721.0	-0-	2.4		2.62	2.56		Dense muddy sand
13	722.0	0.2	11.8		2.64	2.33		Shaly sand
14	723.0	0.3	11.8		2.65	2.34		Shaly sand
15	724.0	1.0	13.8		2.68	2.31		Shaly sand
16	725.0	0.8	14.9		2.69	2.29		Shaly sand
17	726.0	1.6	16.7		2.70	2.25		Shaly sand
18	727.0	3.1	15.4		2.66	2.25		Shaly sand
19	728.0	0.1	7.0		2.65	2.46		Shaly sand
20	729.0	0.4	11.2		2.66	2.37		Shaly sand
21	730.0	0.9	11.9		2.66	2.34		Sand
22	731.0	2.0	13.6		2.63	2.27		Sand
23	732.0	1.4	13.4		2.63	2.28		Sand
24	733.0	0.4	5.8		2.64	2.49		Sd and shale lam
	Average	1.5	12.1		2.66	2.34		

NOTE: Bulk density measured on dry core plug. Grain density calculated from bulk density and Washburn Bunting porosity.

mk

SUMMARY

(Continued following page)

Sec.	Formation	Depth, Feet From	Depth, Feet To	Feet of Sand	Avg. Perm.	Avg. Por.	Avg. Oil Sat.	Avg. Water Sat.	Avg. Oil Content Bbl/A.Ft

Table 2 (Cont'd)

COMPANY USS Chemicals

WELL Haverhill Disposal Well No. 1

Sample No.	Depth Feet	Air Perm. Md.	Porosity Per Cent		Calc Grain Density	Meas Bulk Density	% Sol in 15% HCl	Remarks
	NEWBURG LIMESTONE		CORE	NO. 2 (1805 - 1835 FEET)			3/4"Plugs	
25	1805.0	-0-	2.6		2.83	2.76	98	Dol, grey, V vugular
26	1806.0	-0-	1.6		2.80	2.76	98	Dol, grey, V vugular
27	1807.0	44.	3.5		2.84	2.74	97	Dol, grey, V vugular
28	1808.0	-0-	0.5		2.81	2.80	98	Dol, grey
29	1809.0	-0-	0.6		2.79	2.77	95	Dol, grey
30	1830.0	-0-	0.7		2.80	2.78	98	Dol, grey
31	1831.0	-0-	1.2		2.76	2.73	89	Dol, grey
32	1832.0	-0-	3.5		2.76	2.66	97	Dol, brn vugular
33	1832.5	2.6	6.8		2.78	2.59	96	Dol, brn V vugular
34	1833.5	-0-	0.9		2.76	2.74	--	Dol, grey
35	1834.5	-0-	1.0		2.78	2.75	93	Dol, grey
Average		4.2	2.1		2.79	2.73	96	

The following porosities were measured on 4" long whole core vugular sections using grain densities from above & calipered bulk volumes.

Sample No.	Depth Feet	Air Perm. Md.	Porosity Per Cent		Calc Grain Density	Meas Bulk Density	% Sol in 15% HCl	Remarks
103	1805.0-06.0	--	6.0		2.82	2.65	--	V vugular, grey dol
104	1806.0-07.0	--	8.5		2.82	2.58	--	V vug, gr dol, cracks
105	1807.0-08.0	--	6.4		2.82	2.64	--	V vugular, grey dol
106	1831.0-32.0	--	5.1		2.76	2.62	--	Sli vug, brn dol
107	1832.0-33.0	--	3.3		2.76	2.67	--	V vugular brn dol
Average			5.9		2.80	2.63		

NOTE: Vugular zones vary from 1/8" to 1-1/4" vugs with large amount of secondary crystal deposition in vugs. Chemical analysis of white crystals indicate dolomite with Ca/mg ratio of 1.91:1. Chemical analysis of grey rock indicates dolomite with Ca/mg ratio of 1.73:1.

bw

SUMMARY

(Continued following page)

Sec.	Formation	Depth, Feet From	Depth, Feet To	Feet of Sand	Avg. Perm.	Avg. Por.	Avg. Oil Sat.	Avg. Water Sat.	Avg. Oil Content Bbl/A.Ft

EARLOUGHER ENGINEERING
RESULTS OF CORE ANALYSES

Table 2 (Cont'd)

COMPANY USS Chemicals

WELL Haverhill Disposal Well No. 1

Sample No.	Depth Feet	Air Perm. Md.	Porosity Per Cent		Calc Grain Density	Meas Bulk Density		Remarks
	ST. PETER	CORE NO. 3 (3979 - 4009.3 FEET)						
36	3979.0	-0-	6.0		2.74	2.58		Shaly dol, grey
37	3984.0	-0-	0.6		2.69	2.67		Limy dol, white
38	3989.0	-0-	1.8		2.74	2.71		Limy dol, white
39	3990.5	-0-	2.9		2.75	2.67		V shaly dol, limy
40	4002.0	-0-	0.4		2.73	2.72		Dol, grey, V.F.
41	4007.0	-0-	3.4		2.78	2.69		Dol, grey
Average		-0-	2.5		2.74	2.67		
	ROSE RUN	CORE NO. 4 (4242.0 - 4246.5 FEET)						
42	4242.0	-0-	0.9		2.65	2.62		Grey dol sand
43	4243.0	-0-	1.2		2.65	2.62		Grey dol sand
44	4244.0	-0-	4.1		2.65	2.54		Sl shly, sl gr dol chert nodules.
45	4245.0	-0-	6.1		2.59	2.44		White sand
46	4246.0	-0-	7.2		2.59	2.40		White sand
Average		-0-	3.9		2.63	2.52		
	ROSE RUN	CORE NO. 5 (4250.0 - 4261.8 FEET)						
47	4250.0	83.	11.1		2.60	2.30		Sand
48	4251.3	53.	10.7		2.62	2.34		Sand
49	4252.5	62.	11.4		2.60	2.31		Sand, sl dol, F
50	4253.8	18.	11.8		2.62	2.31		Sand
51	4255.0	2.1	10.7		2.60	2.32		Shaly sand
52	4256.3	0.3	8.0		2.56	2.36		Shaly sand
53	4257.0	48.	14.9		2.62	2.23		Sand
54	4258.0	52.	14.1		2.58	2.21		Sand
55	4258.8	1.8	10.3		2.58	2.32		Shaly
56	4259.7	1.0	8.5		2.66	2.41		Shaly
57	4261.2	0.3	2.6		2.61	2.55		Sl dol sd w/sh strks
Average		33.	10.4		2.61	2.34		

bw

SUMMARY

(Continued following page)

Sec.	Formation	Depth, Feet		Feet of Sand	Avg. Perm.	Avg. Por.	Avg. Oil Sat.	Avg. Water Sat.	Avg. Oil Content Bbl/A.Ft
		From	To						

COMPANY USS Chemicals

WELL Haverhill Disposal Well No. 1

Sample No.	Depth Feet	Air Perm. Md.	Porosity Per Cent	Kw	Calc Grain Density	Meas Bulk Density		Remarks
	MT. SIMON	CORE NO. 6 (5532.0-5560.8 FEET)						
58	5532.2	4.9	7.3		2.65	2.47		Sand, shaly
59	5533.0	-0-	1.2		2.46	2.43		Sand
60	5534.0	0.4	3.5		2.62	2.53		Sand
61	5535.0	11.	4.4		2.71	2.59		Sand, shaly
62	5535.8	27.	11.9		2.61	2.30		Sand
63	5537.2	94.	14.1		2.64	2.22		Sand
64	5538.0	71.	14.1		2.57	2.21		Sand
65	5539.0	21.	13.9		2.60	2.24		Sand
66	5540.0	18.	10.6	21.5	2.56	2.29		Sand
67	5541.0	65.	13.6		2.59	2.24		Sand, VF
68	5542.0	60.	14.6		2.55	2.18		Sand
69	5543.0	6.7	11.1		2.63	2.34		Sand
70	5544.0	48.	13.4	10.2	2.53	2.19		Sand
71	5545.0	55.	14.2		2.58	2.21		Sand
72	5546.0	22.	12.9		2.58	2.25		Sand
73	5547.0	21.	14.9	7.2	2.53	2.15		Sand
74	5548.0	75.	13.7		2.57	2.22		Sand
75	5549.0	42.	14.4		2.55	2.18		Sand
76	5550.0	48.	15.7		2.55	2.15		Sand
77	5551.0	39.	15.6		2.52	2.13		Sand
78	5551.9	7.6	14.0	3.7	2.56	2.20		Sand
79	5553.0	43.	15.7		2.55	2.15		Sand
80	5554.0	2.7	10.7		2.54	2.27		Sand
81	5555.0	1.1	14.0		2.56	2.20		Sand
82	5556.0	14.	15.9		2.54	2.14		Sand
83	5557.0	5.1	13.1		2.52	2.19		Sand
84	5558.0	1.0	10.8		2.58	2.30		Sand
85	5558.9	0.6	10.0		2.57	2.31		Sand, shaly
86	5559.9	0.5	10.8		2.53	2.26		Sand, shaly
87	5560.7	0.1	7.8		2.51	2.31		Sand, shaly
Average		26.8	11.9		2.55	2.26		

Kw = Permeability to distilled water of 1-1/2" plug.

SUMMARY

(Continued following page)

Sec.	Formation	Depth, Feet From	Depth, Feet To	Feet of Sand	Avg. Perm.	Avg. Por.	Avg. Oil Sat.	Avg. Water Sat.	Avg. Oil Content Bbl/A.Ft

RESULTS OF CORE ANALYSES

Table 2 (Cont'd)

COMPANY USS Chemicals

WELL Haverhill Disposal Well No. 1

Sample No.	Depth Feet	Air Perm. Md.	Porosity Per Cent				Avg. Oil Content Bbl./A. Ft.	Remarks
	MT. SIMON	CORE NO. 7 (5563-5573 FEET)						
88	5563.4	-0-	3.5					Shaly sand
89	5564.3	-0-	1.3					Shaly sand
90	5565.4	-0-	6.4					Shaly sand
91	5566.6	3.9	8.6					Shaly sand
92	5567.5	-0-	6.2					Shaly sand
93	5568.4	0.1	6.1					Shaly sand
94	5569.5	-0-	1.8					Shaly sand
95	5570.4	-0-	1.8					Shaly sand
96	5571.4	-0-	2.4					Limy sand
97	5572.4	-0-	0.7					Limy sand
Average		0.4	3.9					
	CORE NO. 8 (5595-5617 FEET) GRANITE, NOT ANALYZED							

mk

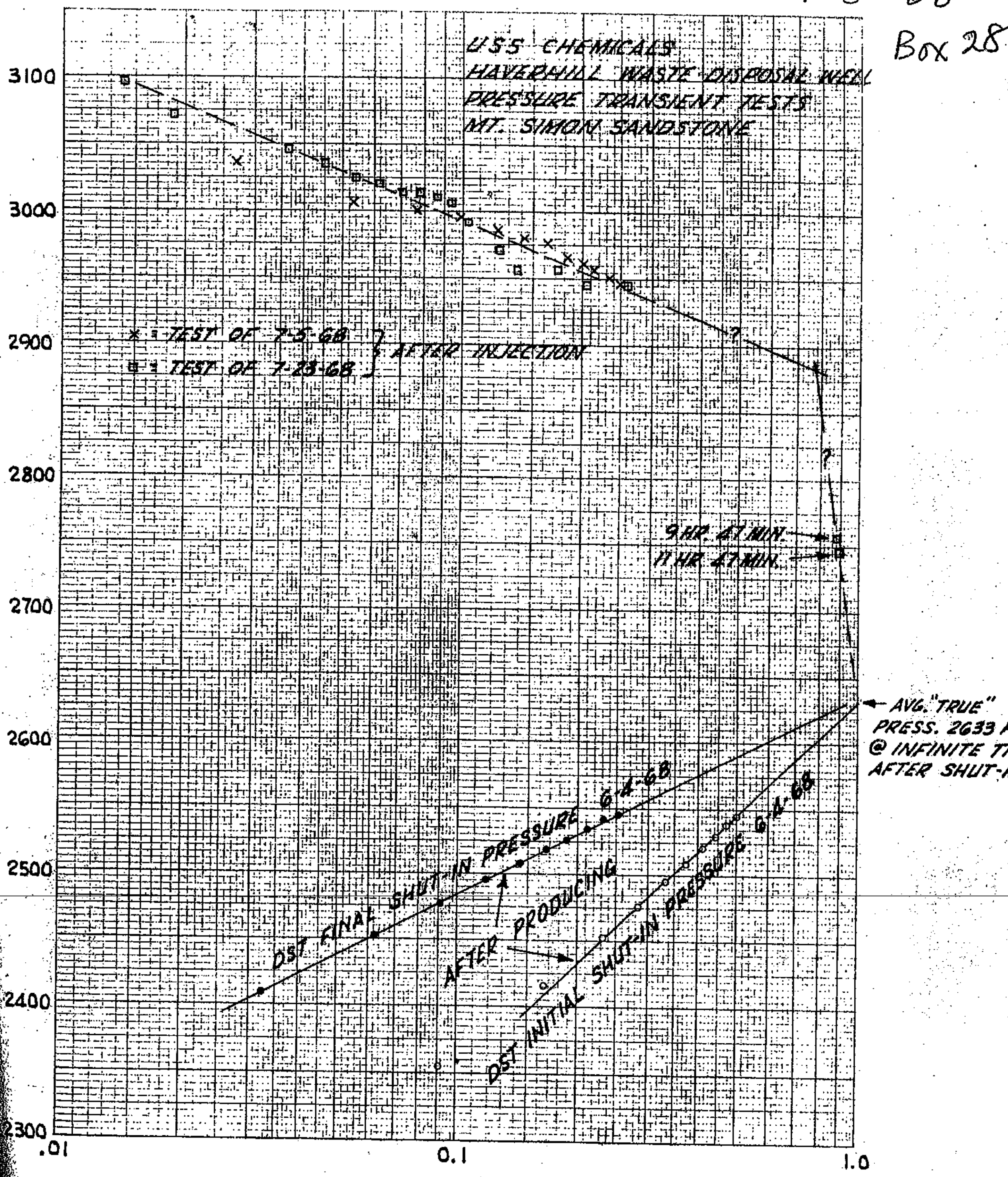
SUMMARY

Sec.	Formation	Depth, Feet		Feet of Sand	Avg. Perm.	Avg. Por.	Avg. Oil Sat.	Avg. Water Sat.	Avg. Oil Content Bbl/A.Ft
		From	To						

Barcode 002630

P8-68

Box 28



$\frac{\Delta t}{t + \Delta t}$ Δt = TIME AFTER SHUT-IN

t = TOTAL FLOW TIME BEFORE SHUT-IN

FIG. 3

Barcode 002630

8.1 Annulus Pressure Test Well No. 1

Waste Disposal Well No. 1 was shut-in and prepared for testing at 6:00 a.m. on Sunday November 8, 1987. A high pressure pneumatic pump was used to pressurize the annulus to 2240 psi the following Monday morning. Approximately 100 psi was bled off the annulus to allow any entrained air to escape. The well was repressurized to 2250 psig and the official mechanical integrity test was started at 10:00 a.m. After 1 hour, the pressure had fallen 50 psi; this was within the 3% limit imposed by the OEPA. After an additional 30 minutes, only 10 psi was lost indicating that the well was reaching stable equilibrium. The initial pressure loss was therefore due to thermal effects and the introduction of trapped air into the annulus.

Mike Moschell, OEPA communicated with Ernie Rotering, after witnessing the annulus pressure test. Approval was granted to commence injection and the well was put back into service. A copy of the pressure test report is presented in Table 8.1.0-I.

8.2 Annulus Pressure Test Well No. 2

Waste Disposal Well No. 2 was shut-in and prepared for testing on Wednesday, October 28, 1987. The official pressure test was performed at 10:30 a.m. and was witnessed by Mike Moschell (OEPA). The test was conducted at 2245 psig. No loss was recorded after 1 hour. A copy of the pressure test report is presented in Table 8.2.0-I.

TABLE 8.1.0-I

ANNULAR PRESSURE TEST

OPERATOR/OWNER Aristech Chem. STATE PERMIT NO. ____
ADDRESS Box 127 EPA PERMIT NO. ____
Ironton DATE OF TEST 10/28/87
WELL NAME/NUMBER WDW #2 CLASS 1
LOCATION Plant TOWNSHIP Green COUNTY Scioto
CORRECTIVE ACTION ____ MECHANICAL INTEGRITY Pressure Test
COMPANY REPRESENTATIVE L. McCain FIELD INSPECTOR M. Moschell
TYPE PRESSURE GAUGE Ashcroft INCH FACE ____ PSI FULL SCALE, 10 PSI INCREMENTS

NEW GAUGE YES __ NO ✓ IF NO, DATE OF TEST CALIBRATION ____
CALIBRATION CERTIFICATION SUBMITTED: YES ✓ NO __

RESULTS:

	PRESSURE (PSIG)	
TIME	ANNULUS	TUBING
10:30	2245	
10:40	2245	
10:50	2245	
11:00	2245	
11:10	2245	
11:20	2245	
11:30	2245	

TEST PRESSURE:

MAX. ALLOWABLE PRESSURE CHANGE: TEST PRESSURE X .03 (1739) 2173 → 2245 PSI
ONE HOUR PRESSURE CHANGE 67 PSI

TEST PASSED ☑ TEST FAILED ☐ (CHECK ONE)
IF FAILED, NO INJECTION MAY OCCUR UNTIL CORRECTIONS HAVE BEEN MADE AND WELL PASSES.

Larry B McCain 10/28/87
SIGNATURE OF COMPANY REPRESENTATIVE DATE

Michael Moschell 10/28/87
SIGNATURE OF OEPA REPRESENTATIVE DATE

OEPA-1987
1524U

Table 8.2.0-I

ANNULAR PRESSURE TEST

OPERATOR/OWNER Aristech Chem. STATE PERMIT NO. ______

ADDRESS Box 127 EPA PERMIT NO. ______

Ironton, Ohio 45638 DATE OF TEST 11/9/87

WELL NAME/NUMBER WDW #1 CLASS 1

LOCATION PLANT TOWNSHIP GREEN COUNTY SCIOTO

CORRECTIVE ACTION ______ MECHANICAL INTEGRITY Pressure Test

COMPANY REPRESENTATIVE L. McCain FIELD INSPECTOR M. Moschell

TYPE PRESSURE GAUGE Ashcroft INCH FACE ______ PSI FULL SCALE, 10 PSI INCREMENTS

NEW GAUGE YES ___ NO ✓ IF NO, DATE OF TEST CALIBRATION ______

CALIBRATION CERTIFICATION SUBMITTED: YES ✓ NO ___

RESULTS:

PRESSURE (PSIG)

TIME	ANNULUS	TUBING
10:00	2250	1188
10:10	2240	
10:20	2230	
10:30	2220	
10:40	2210	
10:50	2210	
11:00	2200	1185
11:30	2190	1181

TEST PRESSURE: 2250

MAX. ALLOWABLE PRESSURE CHANGE: TEST PRESSURE X .03 67.5 PSI

ONE HOUR PRESSURE CHANGE 50.0 PSI

TEST PASSED ☑ TEST FAILED ☐ (CHECK ONE)

IF FAILED, NO INJECTION MAY OCCUR UNTIL CORRECTIONS HAVE BEEN MADE AND WELL PASSES.

Larry S McCain 11/9/87

SIGNATURE OF COMPANY REPRESENTATIVE DATE

Michael Moschell 11/9/87

SIGNATURE OF OEPA REPRESENTATIVE DATE

OEPA-1987
1524U

P2-91

002637

Box 35

CITED

DGS CORE # 3409

APPENDIX H

CORE ANALYSIS - SELECTED INTERVALS

PETROGRAPHIC ANALYSIS OF SELECTED SAMPLES FROM ARISTECH CHEMICAL CORP.'S TEST/MONITOR WELL HAVERVILL, OHIO

PREPARED FOR:

ENVIROCORP SERVICE & TECHNOLOGY
3600 McGILL STREET
SOUTH BEND, INDIANA 46628

PREPARED BY:

TERRATEK GEOSCIENCE SERVICES
PETROGRAPHIC SERVICES GROUP
360 WAKARA WAY
SALT LAKE CITY, UTAH 84108

JUNE 1991
TTGS FILE NO. 5960

INTRODUCTION

Five core samples from the Knox Group and underlying Rome Formation from Aristech Chemical Corporation's test/monitor well in Haverhill, Ohio, were sent to TerraTek for routine porosity/permeability measurements and petrographic analysis. Petrographic analysis performed on these Cambro-Ordovician samples consists of thin section microscopy, X-ray diffraction analysis, and scanning electron microscopy. Table 1 lists depths and stratigraphic interval for each sample.

Table 1
Samples Analyzed

Depth	Stratigraphic Interval
4021.0 - 22.1	Knox Group - Beekmantown Member
4192.9 - 94.0	Knox Group - Rose Run Member
4201.9 - 03.1	Knox Group - Rose Run Member
4591.5 - 93.1	Knox Group - Copper Ridge Member
5196.6 - 97.0	Rome Formation

ANALYTICAL PROCEDURES

1. Petrographic Analysis

Thin section samples were impregnated with blue dye epoxy or red fluorescent epoxy under high vacuum to access matrix porosity, microfractures, and micropores within the sample rock fabric. Samples were then slabbed, mounted to either standard thin section slides or oversized 2" x 3" glass slides, and ground to a thickness of approximately 30 microns. Portions of thin sections were stained with Alizarin Red and potassium ferricyanide to facilitate identification of dolomite, calcite, and ferroan carbonates. Individual samples were analyzed to determine rock classification, mineralogy, diagenesis, and porosity type(s).

2. X-Ray Diffraction Analysis (XRD)

<u>Bulk Analysis</u>: Representative one-gram splits of bulk samples are ground in acetone in agate mortar to <325 mesh (<45 um) then scanned at 2°2θ per minute from 2-65°2θ. Diagnostic peaks of minerals identified on resulting diffractograms are rescanned on duplicate samples. Approximate weight percentages of the minerals are determined by comparing diagnostic peak intensities with those generated by standard pure phases mixed in various known proportions.

<u>Clay Analysis</u>: Bulk samples, at least 35 grams if possible, are sonically disaggregated in deionized water, allowed to settle sufficiently to yield the desired particle size fraction (generally <2 um or <5 um), decanted, and centrifuged. The resulting slurries are smeared on glass slides and x-rayed at 1°θ per minute following air-drying (2-37°), vapor glycolation for 24 hours at 60°C (2-22°), heating to 250°C for one hour (2-15°) and heating to 550°C for one hour (2-25°). Approximate weight percentages of the layer silicates identified on diffractograms corresponding to these treatments are determined by comparison of diagnostic peak intensities with those generated by pure reference clays in appropriate mixtures.

3. Scanning Electron Microscopy (SEM)

SEM samples prepared from core material were mounted on an SEM sample mount and coated under high vacuum with gold. Samples were then examined using a Hitachi S-450 SEM equipped with a Kevex energy dispersive X-ray spectrometer. Samples were examined and photographed at a range of magnifications to exhibit the morphology of the rock fabric and pore system. Identification of pore-lining or pore-filling components was made whenever possible.

KNOX GROUP, BEEKMANTOWN MEMBER

Sample 4021 from the Beekmantown Member of the Knox Group is characterized by finely crystalline dolomite. X-ray diffraction (Table 2) indicates that dolomite and quartz are the dominant components. Minor amounts of late stage pyrite were also observed in thin section. Relicts of a somewhat laminated bioturbated fabric are present, but dolomitization has been fairly pervasive and destroyed most original texture.

Porosity is dominated by vugs of various sizes. Many are elongate features parallel to laminations, which may be the remnants of a fenestral fabric. Very little intercrystalline porosity was observed in the matrix. Most vugs are lined to filled by euhedral dolomite crystals. Larger vugs, which range up to 2 cm in diameter, commonly contain dolomite rhombs up to 5 mm in diameter. The quartz measured in the x-ray diffraction is a pore-filling component which precipitated prior to the euhedral dolomite. Pore-filling quartz is somewhat irregularly distributed, whereas pore-lining/filling euhedral dolomite is present in almost all vugs. Pyrite is also a late pore-filling component. Several narrow fractures were also observed.

A porosity value of 2.2% was measured in the routine analysis. Visual inspection of the interval suggests that porosity varies somewhat locally. Some vugs may also be isolated and ineffective. Maximum horizontal permeability of 231 md was measured in one direction but only 0.02 md in the other horizontal direction and in a vertical orientation. The high horizontal value indicates that some vugs are well interconnected, at least on the scale of the whole core. No fractures large enought to account for this high permeability value exist in the full diameter sample.

TABLE 2

X-ray Diffraction Analysis

Sample No.	4201		4202		4192		4593		5196.5	
	Bulk	Clay	Bulk	Clay	Bulk	Clay	Bulk	Clay	Bulk	Clay
Quartz	14		98		84		13		Tr	
Plagioclase							1			
K-feldspar			2				11		1	
Dolomite	86				16		71		98	
Pyrite					Tr		2			
Halite			Tr							
Kaolin										
Illite (± 10A Mica)							2	78	Tr	72
M.L. Chlorite/ Smectite							Tr	22	Tr?	28

The diagenetic sequence envisioned for this sample is as follows:

1. Deposition of carbonate mud in a shallow marine setting.
2. Compaction and lithification of lime mud.
3. Fracturing.
4. Dolomitization and dissolution.
5. Precipitation of pore-filling quartz.
6. Precipitation of pore-lining/filling euhedral dolomite.
7. Precipitation of pore filling pyrite.

KNOX GROUP, ROSE RUN MEMBER

Two samples, 4193' and 4202', were analyzed from the Rose Run Member of the Knox Group.

Sample 4193' is composed mainly of chert. This rock was originally an oolitic limestone but has been completely silicified. Original textures and fabrics have been preserved through replacement of calcitic textural elements by silica. Ooids range from medium to coarse sand size and were originally cemented by calcite. Ooids with both radial and concentric internal structure are present. Silicified intraclasts are also present but are much less abundant than ooids. Partially open and partially filled fractures disrupt the fabric and form a brecciated mosaic of silicified clasts.

A number of different conventional or unconventional porosity types were observed in this sample. On one hand, two different generations of fractures are present. An earlier set formed prior to silicification and is partially filled by silicified isopachous calcite and ankerite, which precipitated following silicification. Significant amounts of porosity remain along this fracture set. The second generation of fractures occurred relatively late. These fractures are partially open and form an orthogonal network across the sample. Conventionally, interparticle porosity is present between ooids, and intraparticle porosity is present within ooids and intraclasts. Intraparticle porosity is dominated by microporosity as indicated by SEM analysis. Finally, vugs and dissolution voids are also present. Dissolution porosity formed prior to silicification. Interparticle, intraparticle, and vuggy porosity present prior to silicification was not destroyed during silica diagenesis.

A routine porosity value of 9.1% was measured for this sample. Of the porosity types present, fracture porosity and interparticle porosity are the most significant. Microintraparticle and vuggy porosity are less abundant than fracture and intraparticle poroisty. Intraparticle porosity within carbonate grains is likely ineffective in transmitting fluids. Measured permeabilities range form 0.07 md to 6.0 md. Fractures likely play an important role in permeability. Vertical permeability (0.07 md) is reduced by low angle stylolites near the middle of the full diameter sample.

Diagenesis of this interval is relatively complex. The following is a generalized sequence indicating major diagenetic events:

1. Deposition of carbonate grains in a shallow marine setting.
2. Cementation by calcite.
3. Compaction and fracturing.
4. Precipitation of isopachous fracture lining calcite cement.
5. Dissolution and formation of vuggy porosity.
6. Pyrite precipitation.
7. Silicification.
8. Precipitation of fracture-filling ankerite in early fractures.
9. Formation of late orthogonal fracture set.

Sample 4202', also from the Rose Run Member is a quartz rich sandstone and plots in the upper portion of the subarkose field of a Folk (1974) sandstone classification diagram (Figure 1). Monocrystalline quartz is the dominant framework component although minor amounts of polycrystalline quartz are also present. Potassium feldspar is dominated by microcline and constitutes 2% to 3% of framework grains. Lithic grains and chert constitute another 2% to 3% of the major mineralogy. Many lithics are partially dissolved and are probably sedimentary rock fragments. No accessory grains were observed in this thin section.

The sample is dominated by fine to medium grained sand. Median grain size of 2.02 ϕ was measured for 50 random grains (Figure 2). Framework grains are rounded and moderately well to well sorted. Grain contacts are dominated by point and long contacts, indicating relatively minor compaction.

Figure 1. Modal Analysis

Company : Aristech Chemical Corporation
Well : Test/Monitor, Haverhill, Ohio
Formation : Knox, Rose Run Member
n = 1

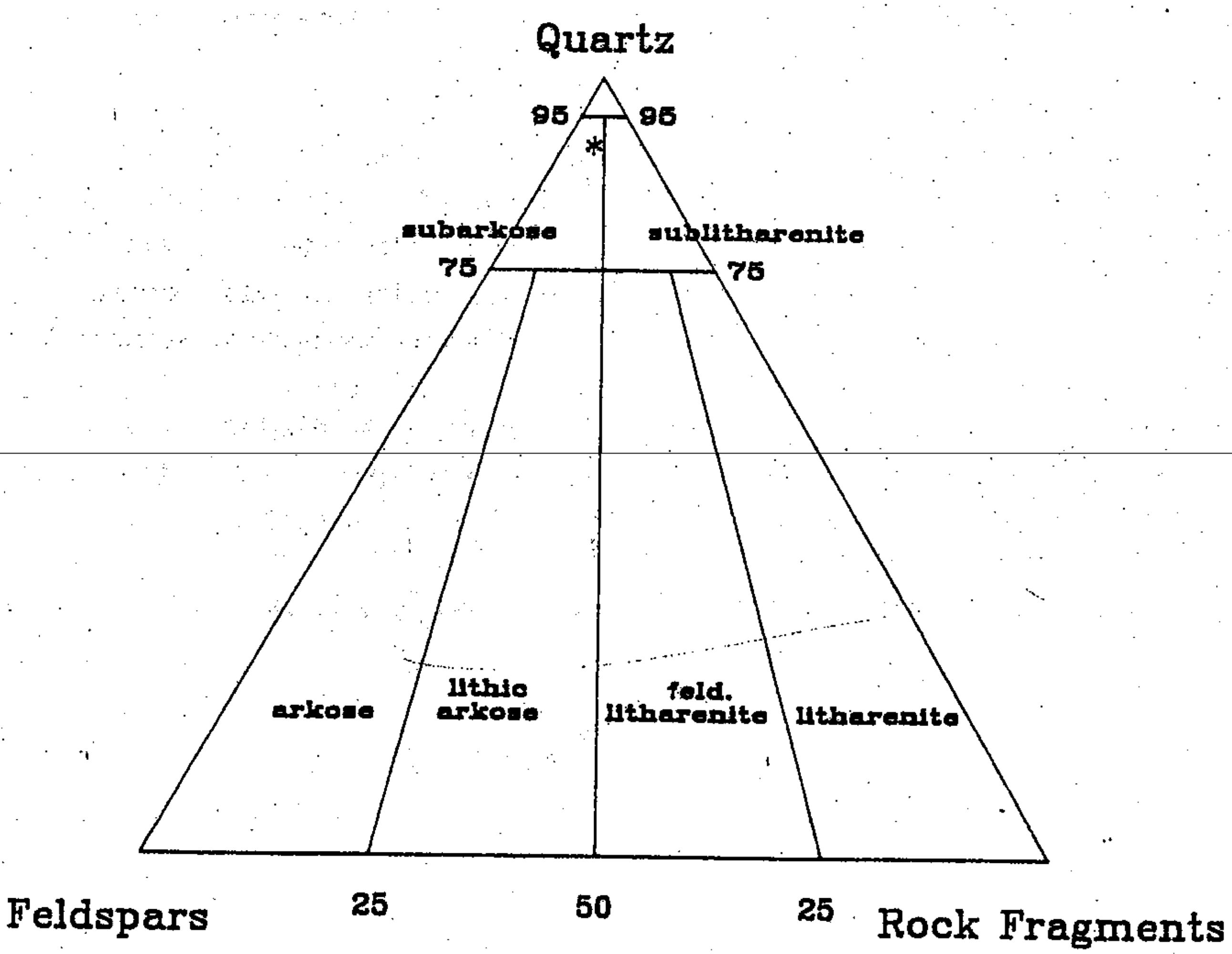
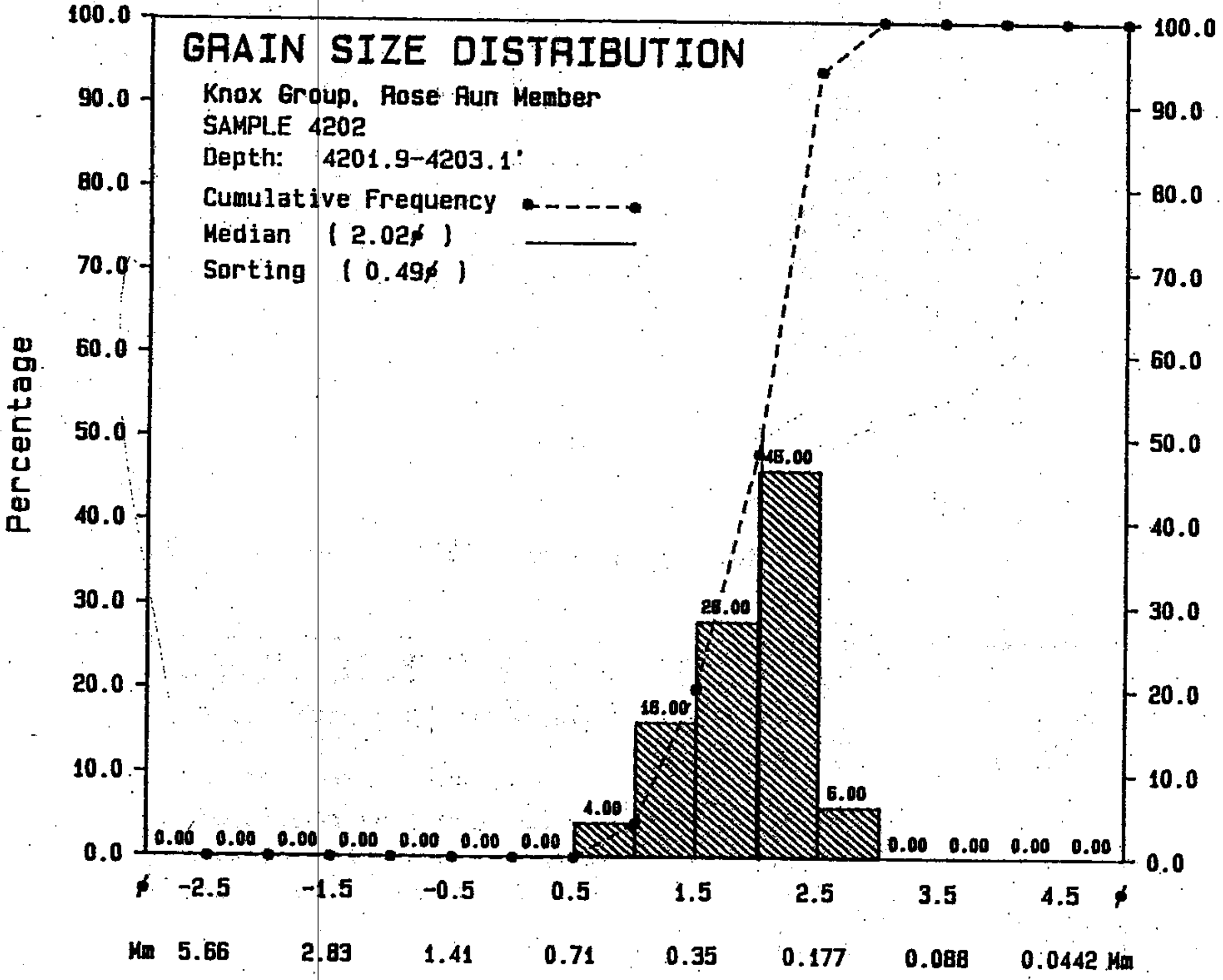


FIGURE 2. GRAIN SIZE HISTOGRAM OF SAMPLE 4202.



X-ray diffraction analysis (Table 2) shows very little clay in the sample. SEM analysis encountered minor amounts of mixed-layer illite-smectite. Illite-smectite exhibits pore-lining and pore-filling morphologies, but constitutes less than 1% of the bulk composition.

Quartz and feldspar are the dominant cements. Both are present as overgrowths on framework grains. No carbonate cement was observed, but may have been a factor in the diagenetic history. Calcite, if once present, has been removed through dissolution.

Porosity is dominated by intergranular and "moldic" pores formed by the complete dissolution of framework grains. Lithic and feldspar grains, along with carbonate cements that may have been present, have been removed by acidic formation waters. Short, high-angle, partially open fractures are present but probably only affect this interval locally. Minor amounts of intragranular porosity within partially dissolved grains were also observed.

Porosity and permeability are greatest in this sample. Intergranular porosity constitutes a major portion of the 12.1% measured in the routine analysis. Horizontal permeability measurements do not show significant variation, suggesting that fractures do not significantly affect permeability.

The following diagenetic sequence is envisioned for this sample:

1. Deposition in a shallow marine setting.
2. Compaction
3. Formation of silica and feldspar overgrowths.
4. Calcite cementation.
5. Fracturing.
6. Dissolution.
7. Formation of minor pore-lining and pore-filling illite-smectite.

KNOX GROUP, COPPER RIDGE MEMBER ("B" ZONE?)

Sample 4593', from the Copper Ridge Member of the Knox Group, is characterized by silty dolomite interlaminated with thin siltstone or very fine sandstone laminae. Dolomite laminae are finely crystalline and contain scattered quartz and feldspar silt. Silt and very fine sand also occur in this laminae. Siltstone laminae are lightly bioturbated and define ripple marks in one portion of the sample. Siltstone laminae are cemented by a combination of quartz and dolomite cements. Rounded to elongate siliceous nodules are aligned parallel to some laminations. These nodules were evaporitic in origin, probably anhydrite nodules that silicified later. Several stylolites were also observed at the interface between rock types.

X-ray diffraction analysis (Table 2) indicated that quartz and feldspar grains are about equal in abundance. Illite and mixed-layer chlorite-smectite are the dominant clay minerals. SEM analysis indicates that these clays have pore-lining and pore-filling morphologies in siltstone laminae. Clays appear more abundant in siltstone laminae than in the silty dolomite. Pyrite is also present and is typically a late stage replacive or pore-filling component.

Porosity is dominated by microporosity in siltstone laminae. Porosity is also observed within the silicified evaporite nodules. Porosity in silicified nodules is present between quartz crystals and individual pores can be relatively large. Former evaporite nodules are, however, limited in extent and typically isolated. Porosity within nodules is likely isolated and ineffective. The 2.7% porosity measured in this sample is primarily microporosity within siltstone laminae. Very little porosity was observed in silty dolomite laminae. Permeability is relatively low, reflecting the dominance of microporosity.

The following diagenetic sequence is envisioned for this sample:

1. Deposition in a restricted shallow marine setting.
2. Bioturbation.
3. Compaction and formation of stylolites.
4. Silicification of evaporite nodules; silica cementation of siltstone laminae.
5. Precipitation of pore-filling and replacive pyrite.

ROME FORMATION

Sample 5196 represents the Cambrian Rome Formation and is characterized by medium to coarsely crystalline dolomite. As indicated by X-ray diffraction (Table 2), dolomite is the dominant mineral component. The minor amount of quartz and feldspar measured in the XRD analysis occurs as scattered detrital grains. Clay minerals are concentrated in discontinuous more finely crystalline patches, which may be burrows. Texture and distribution of these clayey, finely crystalline patches are suggestive of bioturbation. Dolomitization has been extensive and obliterated almost all original fabric. Wispy compaction-related stylolites are present in clayey portion of the sample.

Vugs and, to a lesser degree, fractures dominate porosity. Vuggy porosity is well developed throughout most of the sample. Most vugs and fractures are lined to partially filled by euhedral dolomite crystals. The outer edges of pore-lining dolomite rhombs are composed of ankerite indicating a change in formation water chemistry with time. Some parts of the sample are poorly impregnated with the fluorescent epoxy, suggesting isolation of vugs or extremely small pore throats.

Porosity measured in the routine analysis is 3.6%. Permeability measurements show significant variation indicating the probable importance of fractures to permeability. Fractures are present in both clayey and clay-free portions of the sample. Vugs were only observed in clay-free areas.

The diagenetic sequence for this sample is as follows:

1. Deposition of carbonate material in a shallow marine setting.
2. Lithification.
3. Compaction and stylolite formation.
4. Fracturing.
5. Dolomitization and dissolution forming vuggy porosity.
6. Precipitation of pore-lining/filling dolomite.
7. Precipitation of pore-lining/filling ankerite.

TABLE 3

Full Diameter Permeability and Porosity Data
Aristech Test/Monitor Well

Sample Number	Depth (ft)	Permeability			Porosity (%)	Grain Density (gm/cc)	Lithology
		Kmax (md)	K-90 (md)	Vert (md)			
1	4021.0-22.0	231	.02	.02	2.2	2.79	Dol,ltgy,cxl,vgy,frac,suc,lf
2	4193.0-94.0	6.0	3.3	.07	9.1	2.65	Cht,ltbrn-ltgrn,wthrd,mgr, ss stk,sty
3	4202.0-03.0	86	70	1.4	12.7	2.64	Ss,wh,mgr,sil,bdd,sty
4	4592.5-93.1	.10	.06	<.01	2.7	2.73	Ss,mgy,vfgr,v/dol,calc xls,sty, dd
5	5196.5-97.0	1.8	.04	1.7	3.6	2.84	Dol,ltgy-ltgrn,c-vcxl,vgy,intxl,sty

DESCRIPTION SCHEME FOR CARBONATE SEDIMENTARY ROCKS:
ROCK TYPE, COLOR, GRAIN SIZE / CRYSTAL SIZE, POROSITY TYPE, ACCESSORIES

KEY TO ABBREVIATIONS:

aff - anhydrite filled fracture
alt - altered
anhy - anhydrite(ic)
arg - argillaceous
bdd - bedded
bent - bentonite
bf - buff
biot - bioturbated
bit - bitumen
bl - blue(ish)
blk - black
bnd - banded
brec - breccia(ted)
brn - brown
bur - burrowed
c - coarse
calc - calcite(areous)
carb - carbonaceous
cff - calcite filled fracture
cgl - conglomerate
chky - chalky
chlor - chlorite
cht - chert
chty - cherty
cly - clay(ey)
clyst - claystone
dism - disseminated
dk - dark
dff - dolomite filled fracture
dol - dolomite(ic)
f - fine
fen - fenestral
fis - fissile
fos - fossil(iferous)

frac - fracture
fri - friable
gff - gauge filled fracture
glauc - glauconitic
gn - green
gr - grain(ed)
grnl - granule
gy - gray
gyp - gypsum(iferous)
hem - hematite(ic)
if - incipient fracture
incl - inclusion
intprt - interparticle
intrprt - intraparticle
intxl - intercrystalline
lam - laminated
lav - lavender
lig - lignite(ic)
ls - limestone
lt - light
m - medium
mar - maroon
mas - massive
mic - micro
mica - micacious
mol - moldic
nod - nodule(s)
o - oil
of - open fracture
ool - oolitic
org - organic
orng - orange
pbl - pebble
pel - peloids

pff - pyrite filled fracture
pis - pisolitic
pk - pink
pof - partially open fracture
ppvgs - pinpoint vugs
ptg - parting(s)
purp - purple
pyr - pyrite(ic)
qff - quartz filled fracture
qtz - quartz
red - red
sa - salty
sdy - sandy
sh - shale
shy - shaley
sid - siderite
sil - silica(eous)
sl/ - slightly
sltst - siltstone
slty - silty
ss - sandstone
stn - stain(ed)(ing)
str - streak
styl - stylolite
suc - sucrosic
tan - tan
v/ - very
vc - very coarse
vf - very fine
vgy - vuggy
wh - white
wthrd - weathered
yel - yellow
xl - crystalline

DRILL STEM TEST, 6/6/68
USS Chemicals
Final Shut-in Period, Haverhill Disposal Well No. 1
Mt. Simon Sand, Scioto County, Ohio
Test Depth – 4988 Feet True Vertical Sub-Sea Depth

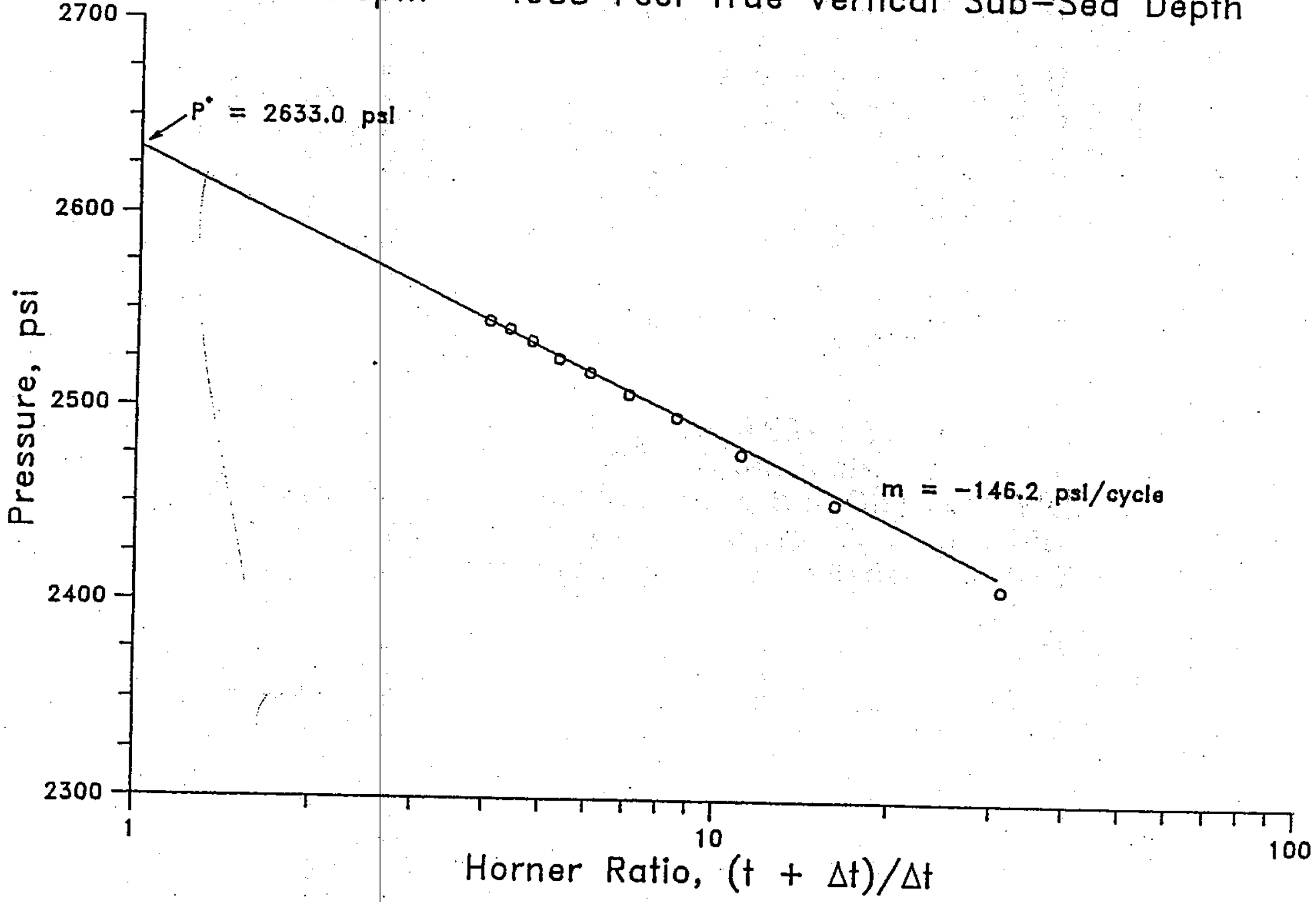


Figure 3

REC, INC.
June 1989

APPENDIX G-4

A REPORT TO ARISTECH CHEMICAL CORPORATION ON STEP-RATE TESTING, WELL NO. 3

(PREPARED BY RESEARCH & ENGINEERING CONSULTANTS, INC., 1991)

P4-91

Barcode

002637

Box 35

A REPORT

TO

ARISTECH CHEMICAL CORPORATION
HAVERHILL, OHIO
ON

STEP-RATE TESTING, WELL NO. 3
MARCH 23 - 25, 1991

PREPARED BY

RESEARCH & ENGINEERING CONSULTANTS, INC.
ENGLEWOOD, COLORADO

APRIL 30, 1991

INTRODUCTION

Aristech Chemical Corporation (Aristech) requested that Research & Engineering Consultants, Inc., (REC) design a step-rate test procedure to be executed in their Well No. 3 at Haverhill, Ohio by Envirocorp. Aristech also requested that REC provide an engineer on-site for the test and that REC evaluate the test data. The Envirocorp report, dated April 2, 1991, describes the step-rate field activities while this report describes the design of the test and evaluation of the data.

RATIONALE FOR THE TEST

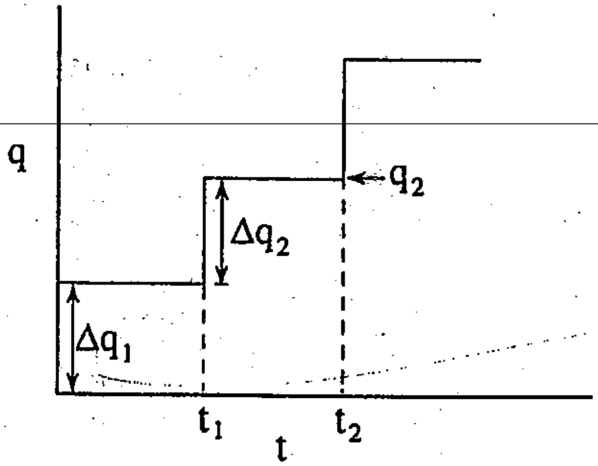
The proposed test was planned in response to an Ohio EPA request. It was noted by that agency that the step-rate test previously conducted in Well No. 3 was not entirely satisfactory because of equipment problems. Specifically, the inability to pump at very low rates precluded obtaining an essential part of the test data.

THEORETICAL BACKGROUND

The basis for design and evaluation of a step-rate test is that superposition of fundamental flow solutions applies to flow of a slightly compressible fluid in a porous medium with unchanging properties. Specifically, for injection into a well with a rate history described by a step function

$$(1) \qquad q = q_n = \sum_{i=1}^{n} \Delta q_i \qquad t_{i-1} < t < t_n$$

as shown in Figure 1.



Step Rate History

FIGURE 1

the bottomhole pressure is [see Collins, 1961]

(2) $$P(t_n) = P_n = P_o + \sum_{i=1}^{n-1} \Delta q_i \frac{\mu}{4\pi K h} \left\{ F\left(\frac{\varphi \mu c r_w^2}{K(t_n - t_i)} \right) + 2S \right\}$$

Here consistent units apply and the symbols are:

K = permeability
ϕ = porosity fraction
μ = viscosity
h = thickness of interval
S = skin factor
P_o = static shut-in pressure
r_w = well radius

In this, the function F is well approximated by the exponential integral function

(3) $$F(x) = \int_x^{\infty} \frac{\bar{e}^{\xi}\, d\xi}{\xi}$$

which is a tabulated function. Now if the skin factor is changed suddenly from one fixed value to a new value at some point in time, then after this time, the pressure is given by

(4) $$P'(t_n) = P_n = P_o + \sum_{i=1}^{n-1} \Delta q_i \frac{\mu}{4\pi K h} \left\{ F\left(\frac{\varphi \mu c r_w^2}{K(t_n - t_i)} \right) + 2S' \right\}$$

Here, if we subtract Eq. (2) from Eq. (4), there results, by virtue of Eq. (1),

(5) $$P_n' - P_n = \frac{2\mu}{4\pi K h}(S' - S)\, q_{n-1}$$

This shows that if one should plot the data of P_n versus q_{n-1} then there should be a change in slope of the resulting graph by the amount

(6) $$\text{slope change} = \frac{2\mu}{4\pi K h}(S' - S)$$

at the point where S changed.

For example, if P_n versus q_{n-1} is well approximated by a straight line

(7) $$P_n = a + b\, q_{n-1} \, , \; n > n_c$$

and similarly for the P_n',

(8) $$P_n' = a' + b' q_{n-1} \, , \; n < n_c$$

then b' - b is given by Eq. (6).

Now, if a well is hydraulically fractured by injection, this effectively introduces a negative change in skin factor. In fact, for a vertical hydraulic fracture of length $2L_f$, bisected by the wellbore, the change in skin factor is, for an infinitely conductive fracture,

(9) $$S' - S = -\ell n \frac{L_f}{2 r_w}$$

Thus, a step-rate test can determine the bottomhole injection pressure at which a fracture is created by identifying the point of a sharp change in slope of the P vs. q plot. However, a more *gradual* change in slope can occur simply due to a slow change in the skin factor in the following manner.

If the formation permeability is K_D, from the well radius out to some radius r_D, and has value K beyond r_D,, then the skin factor can be shown to be,

(10) $$S = \left(\frac{K}{K_D} - 1 \right) \ell n \frac{r_D}{r_w}$$

Hence, if the increase in pore pressure near the wellbore, due to injection, simply "dilates" the pores, this will cause K_D to be greater than K and S to be more negative. This "pressure sensitive permeability" causes a progressively more negative skin factor and hence a gradual decrease in slope of the P versus q plot as pressure increases. This effect will precede the event of fracture initiation, if the formation is previously unfractured, or fracture opening if already fractured, as pressure increases.

The phenomenon of pressure sensitive permeability is directly related to that of permeability reduction due to compaction. For example, Figure 2 exhibits laboratory data showing the decrease in permeability of core plugs due to an increase in confining pressure on the sample. Here, the level of pore pressure was less than 100 psi in all cases i.e. atmospheric effluent pressure. Thus, it is the difference, confining pressure minus pore pressure, which determines permeability variation.

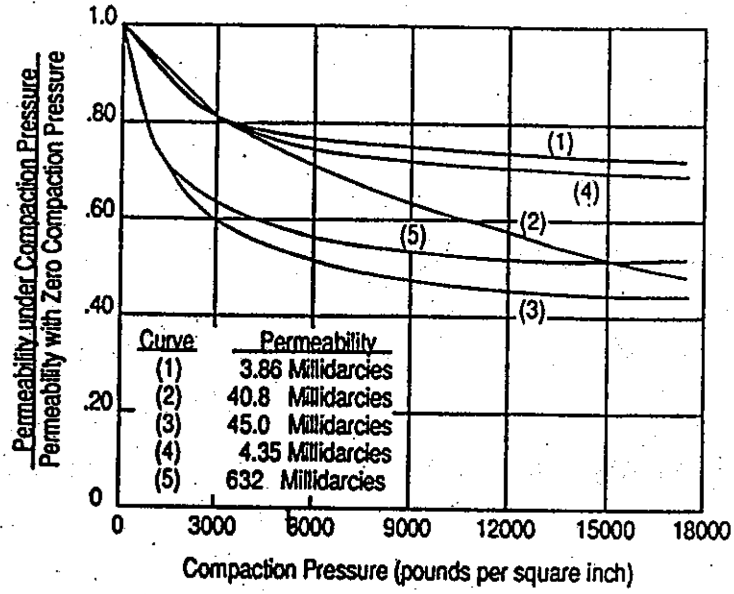


FIGURE 2

Effect of compaction on permeability of consolidated rocks.
(After Fatt and Davis, 1952)

Now, to initiate a fracture in unfractured rock, the wellbore bottomhole pressure must reach the value

(11) $$P_{BD} = 3\,S_h - S_H - P_o + T,$$

but fracture opening can occur at the pressure

(12) $$P_{FO} = 3\,S_h - S_H - P_p$$

if such fractures do exist (Hiamson & Fairhurst, 1967). Here, P_{BD} is the "formation breakdown" pressure and P_{FO} is the "fracture opening" pressure. These pressures are given in terms of the existing principal horizontal tectonic stresses, S_h (minimum) and S_H (maximum), and the insitu pore pressure P_p. It is the tensile strength of rock, T, which defines the difference in P_{BD} and P_{FO}. These relationships are based on the premise of a vertical fracture, as opposed to a horizontal fracture, and indeed it is well documented (Howard and Fast, 1970) that for depths below about 2,000 feet subsurface stresses are such that this will be the case.

TEST DESIGN AND DATA EVALUATION

There are many misconceptions about step-rate testing which are prevalent in the industry. Among these are the assumptions that each rate should be sustained to reach a steady-state pressure. Another is that all rate steps must be equal in magnitude and duration. However, none of these presumptions are really correct. Indeed, all one must do to obtain a good test is to be sure that adequate data points are obtained at pressures below and above the critical pressure. That is, one is simply trying to identify the critical pressure at which the skin factor of the well changes (becomes more negative) and any rate sequence which accomplishes this can, in principle, be used. However, evaluation of a step-rate test is made very much simpler if rate steps of equal duration and magnitude are employed; then, one simply plots the observed bottomhole pressure at the end of each rate step, just prior to the next rate change, versus the rate at that point. The resulting graph should be essentially a "straight line" with a slope change at the critical pressure.

It is essential, however, that the initial rate step must not cause the wellbore pressure to exceed the critical pressure. Indeed, the previous step-rate test in Well No. 3 was not entirely satisfactory because the initial rate was too high. This was a consequence of equipment problems. (A low-rate pump was not available).

Based upon the data obtained durng the previous step-rate test in Well No. 3, and estimates of the critical pressure from other Mt. Simon wells, a maximum lowest rate was estimated which would not cause bottomhole pressure to exceed the critical value ($\approx$ 0.6 x Depth) while injecting at this rate for two hours. Then this rate was proposed as the increment, Δq, to be used for all steps and step durations were limited to 15 minutes. However, upon re-entering Well No. 3, it was found that fill material was in the wellbore and this was cleaned out using coil tubing only to a slant well depth of 6015 ft. Thus, approximately the upper 10 ft of the total 35 ft of Mt. Simon formation was fully exposed to receive injected fluids. This was deemed acceptable for the test since it is the threshold pressure for fracture opening or initiation near the top of the Mt. Simon which is of critical interest.

Three step-rate tests were then executed with rate sequences and resulting pressure data as displayed in Figures 3, 4 and 5. Here, as in the previous step-rate test, there were some mechanical problems; and only in the final test, Step-Rate Test #3, was a truly satisfactory test obtained. The end-step pressures, plotted versus the corresponding rates, do show the classic "two straight line" pattern. The intersection of these two straight lines defines the critical pressure usually identified as P_{BD} or P_{FO}. In this case, the intersection would definitely be P_{FO}, fracture opening pressure, since there was a previous step-rate test. Although Well No. 3 was never fractured during a wellbore stimulation, the rock was slightly fractured during the three previous step rate tests. Therefore, P_{FO} is represented as the intersection of the two lines. There is also evidence of curvature beginning at a lower pressure indicating pressure sensitive permeability.

Now to evaluate these three tests more completely, the data were used with the Injection Forecast model of REC by a history matching process. In this case, the model essentially evaluates Eq. (2) for an input rate history. Thus, by adjusting values of the parameter groups

$$P_o , \frac{\mu}{Kh} , \frac{\phi \mu c h}{Kh} , \text{and } S$$

a match of observed and computed pressures can be achieved.

Model results were generated for two cases, one in which S was maintained at a constant value of 3.0 and one in which the value of S was adjusted to achieve a match in observed and computed pressures. These results are shown in Tables II and III for the fixed parameters shown in Table I below.

TABLE I

P_o = 2630 psi
μ = 0.56 cp
K = 20 md
φ = 0.11
c = 5.5×10^{-6} psi^{-1}
h = 35 ft.

Note that, although six parameters are listed as fixed, some of these can in fact be varied provided that the group values defined above remain fixed. This follows, of course, simply because parameters enter the calculation only in these specific groups.

Observe that the model study indicates in Table III that in the first step-rate injection test the skin factor was very large at the start of injection then steadily decreased and became negative only after a pressure above 3400 psi was reached. This behavior is typical of a well with significant particulate formation permeability damage which "cleans up" with injection. The negative skin indicates either fracture opening or pressure sensitive permeability as discussed above.

The second step-rate test was almost classical and began with a skin of about 3. This skin is consistent with wellbore fill obstructing some of the formation. Observe that skin was reduced with increasing pressure becoming -3 at a pressure above 3400 psi. However, the jump in rate from 20 gpm to 79 gpm was too large and did not allow defining intermediate skin changes.

The third and final test was completely satisfactory. The beginning skin of 0.1 with gradual reduction and ultimately becoming negative to the value of -2.5 was truly classic in form. Comparison of observations and simulated results are shown graphically for Step-Rate Test No. 3 in Figure 6. The slight "overshoot" in computed pressures in the beginning of each step is due to the fact that the actual rate increases are not *instantaneous* as in the simulation.

These data clearly indicate a pressure sensitive permeability with a threshold pressure in the neighborhood of 3200 psi and a fracture opening pressure of 3375 psi. The negative skin factor of -2.5 is contributed by pressure sensitive permeability as well as possible opening of existing fractures. It is not possible to truly distinguish the relative contributions of these two mechanisms from these data.

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Fatt, I. and Davis, D.H., Trans AIME, 195, 329 (1952).

Haimson, B.C. and Fairhurst, D., Soc. Pet. Engr J.7, 310, (1967).

Howard, G.C. and Fast, C.R., Hydraulic Fracturing, Soc. Pet. Engr., Monograph (1970).

TABLE II

ARISTECH CHEMICAL CO.
HAVERHILL, OH
WDW NO.3

BOTTOM HOLE PRESSURE REPORT

```
                                 Pressure
          Time Rate   Vol        Obs Calc          Bottom Hole Pressure
  Date    Days  GPM    MG  Skin  Psi  Psi  PMin= 2000                  PMax= 4000
-------- ----- ---- ----- ----- ---- ----  *-----------------------------------*
                               HISTORY MATCH      * = calc      0 = observ
=================================================================================
STEP RATE TEST #1
03/23/91 13:24   0.0    0   3.0 2630 2630  ***********0
03/23/91 13:36   1.7    0   3.0 3043 2688  *************      0
03/23/91 13:48   2.1    0   3.0 3076 2703  **************     0
03/23/91 14:00   2.3    0   3.0 3087 2713  **************      0
03/23/91 14:12   3.4    0   3.0 3128 2752  ***************     0
03/23/91 14:24   5.0    0   3.0 3176 2809  ****************     0
03/23/91 14:36   6.3    0   3.0 3216 2857  ****************      0
03/23/91 14:49   8.5    0   3.0 3220 2937  ******************    0
03/23/91 15:00  11.1    0   3.0 3264 3031  ********************   0
03/23/91 15:14  17.9    0   3.0 3337 3274  ************************0
03/23/91 15:21   5.0    0   3.0 3150 2855  ****************     0
03/23/91 15:39   0.0    0   3.0 2670 2663  ************0
03/23/91 16:04  60.0    0   3.0 3555 4783  ****************************0********

STEP RATE TEST #2
03/24/91 11:54   0.0    0   3.0 2615 2634  ***********0
03/24/91 12:15   0.7    0   3.0 2630 2658  ***********0*
03/24/91 12:45   1.0    0   3.0 2639 2670  ************0
03/24/91 13:16   1.8    0   3.0 2670 2700  ************0*
03/24/91 13:46   3.0    0   3.0 2721 2745  *************0
03/24/91 14:16   5.6    0   3.0 2805 2841  **************0*
03/24/91 14:45   7.8    0   3.0 2929 2924  *****************0
03/24/91 15:03   0.0    0   3.0 2770 2656  ************* 0
03/24/91 15:35  10.0    0   3.0 3118 3006  ******************* 0
03/24/91 15:37  20.0    0   3.0 3211 3314  **********************0**
03/24/91 15:56   0.0    0   3.0 2663 2665  ************0
03/24/91 16:24  79.0    0   3.0 3682 5478  ******************************0******

STEP RATE TEST #3
03/25/91 10:00   0.0    0   3.0 2617 2637  ***********0
03/25/91 10:30   2.0    0   3.0 2662 2709  ************0*
03/25/91 11:00   3.1    0   3.0 2692 2751  ************0**
03/25/91 11:30   5.5    0   3.0 2756 2840  **************0*
03/25/91 12:00   8.1    0   3.0 2836 2938  ***************0**
03/25/91 12:30  11.5    0   3.0 2956 3067  *****************0**
03/25/91 12:59  15.0    0   3.0 3056 3201  *******************0***
03/25/91 13:30  20.6    0   3.0 3180 3414  *********************0****
03/25/91 13:59  24.1    0   3.0 3267 3554  ***********************0*****
03/25/91 14:30  29.4    0   3.0 3356 3760  ************************0********
03/25/91 15:00  35.3    0   3.0 3437 3989  **************************0**********
03/25/91 15:30  41.2    0   3.0 3485 4221  ***************************0*********
03/25/91 15:34   0.0    0   3.0 3079 2906  *****************  0
03/25/91 15:58  60.0    0   3.0 3622 4897  *****************************0*******
```

TABLE III

ARISTECH CHEMICAL CO.
HAVERHILL, OH
WDW NO. 3

BOTTOM HOLE PRESSURE REPORT

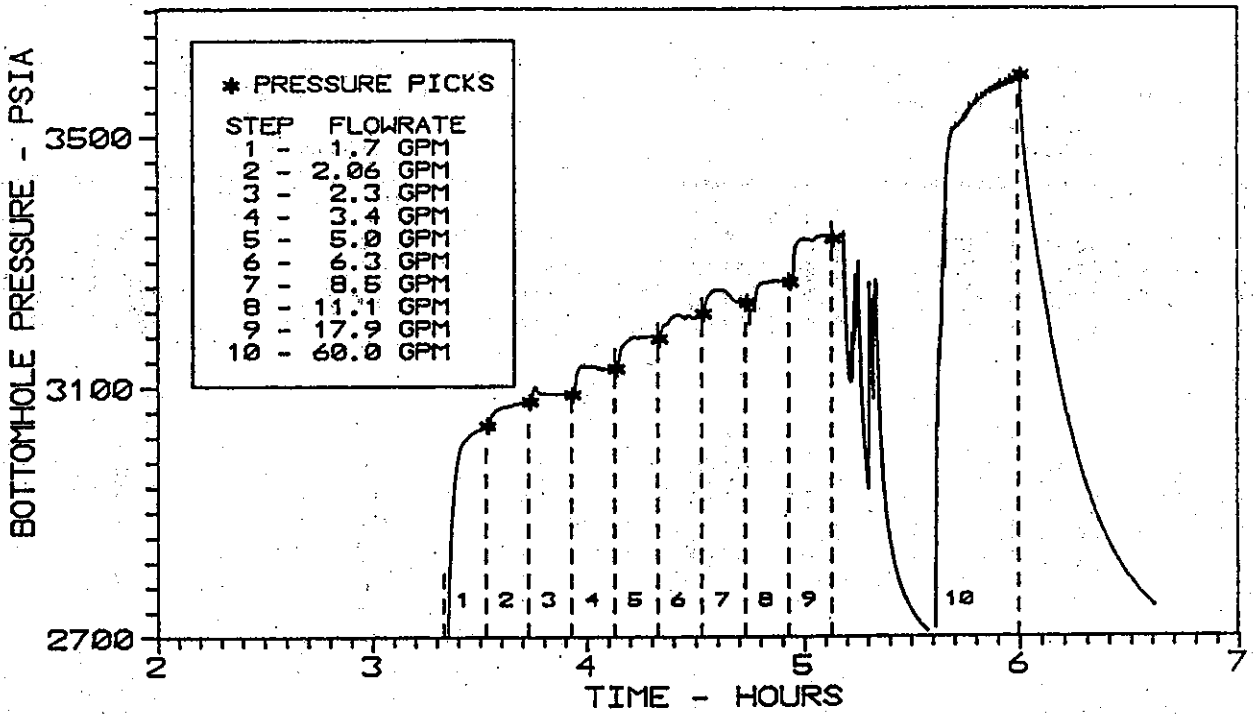
```
                                 Pressure
          Time Rate   Vol         Obs Calc         Bottom Hole Pressure
  Date    Days  GPM    MG  Skin   Psi  Psi  PMin= 2000                    PMax= 4000
-------- ----- ---- ----- ----- ---- ---- *-----------------------------------*
                               HISTORY MATCH     * = calc      0 = observ
===============================================================================
STEP RATE TEST #1
03/23/91 13:24   0.0    0  35.0 2630 2630 ***********0
03/23/91 13:36   1.7    0  31.5 3043 2876 *****************  0
03/23/91 13:48   2.1    0  28.0 3076 2902 *****************  0
03/23/91 14:00   2.3    0  24.5 3087 2904 *****************   0
03/23/91 14:12   3.4    0  21.0 3128 2989 ******************* 0
03/23/91 14:24   5.0    0  17.5 3176 3091 *********************0
03/23/91 14:36   6.3    0  14.1 3216 3127 ********************* 0
03/23/91 14:49   8.5    0  10.3 3220 3177 **********************0
03/23/91 15:00  11.1    0   7.1 3264 3206 ***********************0
03/23/91 15:14  17.9    0   3.0 3337 3274 ************************0
03/23/91 15:21   5.0    0   4.0 3150 2875 *****************    0
03/23/91 15:39   0.0    0   1.3 2670 2663 ************0
03/23/91 16:04  60.0    0  -2.5 3555 3505 ****************************0

STEP RATE TEST #2
03/24/91 11:54   0.0    0   3.0 2615 2634 ***********0
03/24/91 12:15   0.7    0   2.9 2630 2658 ***********0*
03/24/91 12:45   1.0    0   2.7 2639 2669 ************0
03/24/91 13:16   1.8    0   2.4 2670 2696 ************0*
03/24/91 13:46   3.0    0   2.2 2721 2736 *************0
03/24/91 14:16   5.6    0   2.0 2805 2820 **************0*
03/24/91 14:45   7.8    0   1.8 2929 2890 *****************0
03/24/91 15:03   0.0    0   1.7 2770 2656 ************* 0
03/24/91 15:35  10.0    0   1.5 3118 2949 ******************  0
03/24/91 15:37  20.0    0   1.5 3211 3198 **********************0
03/24/91 15:56   0.0    0   3.0 2663 2665 ************0
03/24/91 16:24  79.0    0  -3.0 3682 3642 ******************************0

STEP RATE TEST #3
03/25/91 10:00   0.0    0   0.1 2617 2637 ***********0
03/25/91 10:30   2.0    0   0.1 2662 2686 ************0
03/25/91 11:00   3.1    0   0.1 2692 2716 ************0*
03/25/91 11:30   5.5    0   0.1 2756 2778 **************0
03/25/91 12:00   8.1    0   0.1 2836 2847 ***************0
03/25/91 12:30  11.5    0   0.6 2956 2960 *****************0
03/25/91 12:59  15.0    0   0.6 3056 3062 *******************0
03/25/91 13:30  20.6    0   0.1 3180 3183 *********************0
03/25/91 13:59  24.1    0   0.0 3267 3274 ***********************0
03/25/91 14:30  29.4    0  -0.5 3356 3361 ************************0*
03/25/91 15:00  35.3    0  -1.0 3437 3442 **************************0
03/25/91 15:30  41.2    0  -1.6 3485 3487 ***************************0
03/25/91 15:34   0.0    0   0.0 3079 2906 *****************  0
03/25/91 15:58  60.0    0  -2.5 3622 3619 *****************************0
```

FIGURE 3
STEP RATE TEST #1
ARISTECH CHEMICAL CORPORATION
WATER DISPOSAL WELL #3
MARCH 23, 1991

Gauge at 5441 ft. (vertical) subsurface



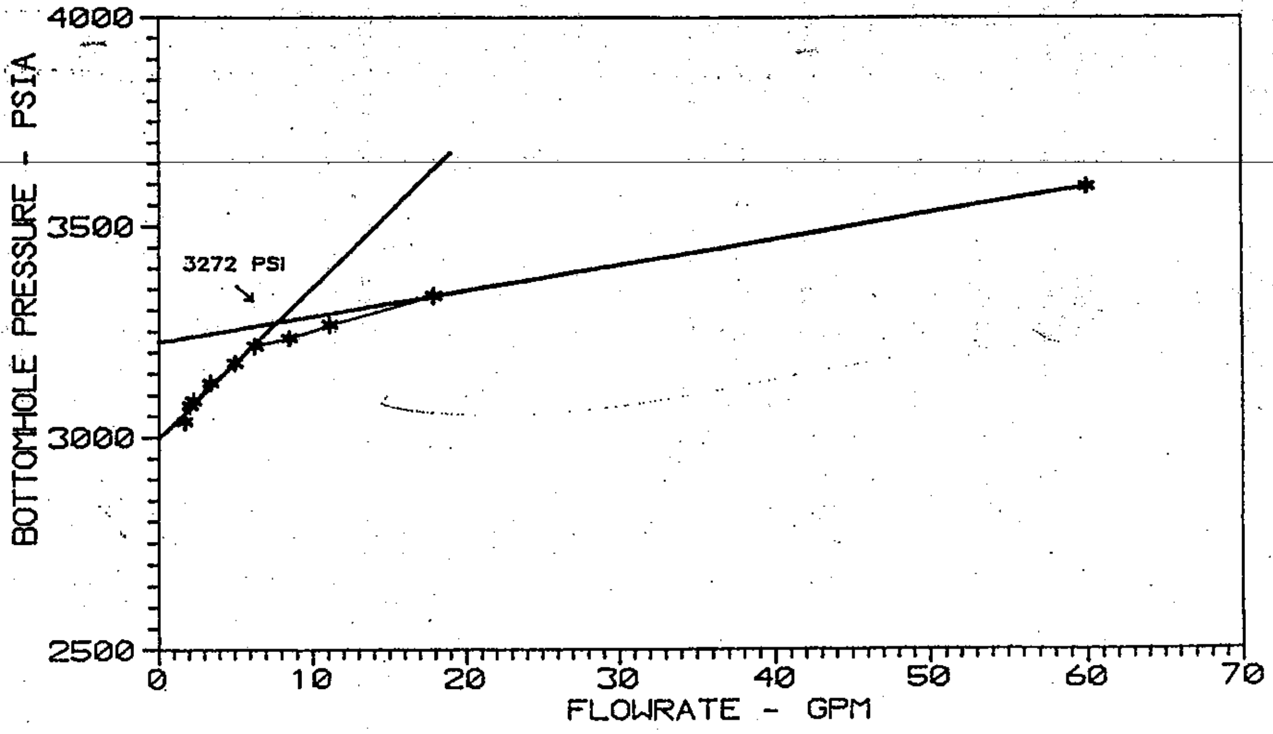


FIGURE 4
STEP RATE TEST #2
ARISTECH CHEMICAL CORPORATION
WATER DISPOSAL WELL #3
MARCH 24, 1991

Gauge at 5441 ft. (vertical) subsurface

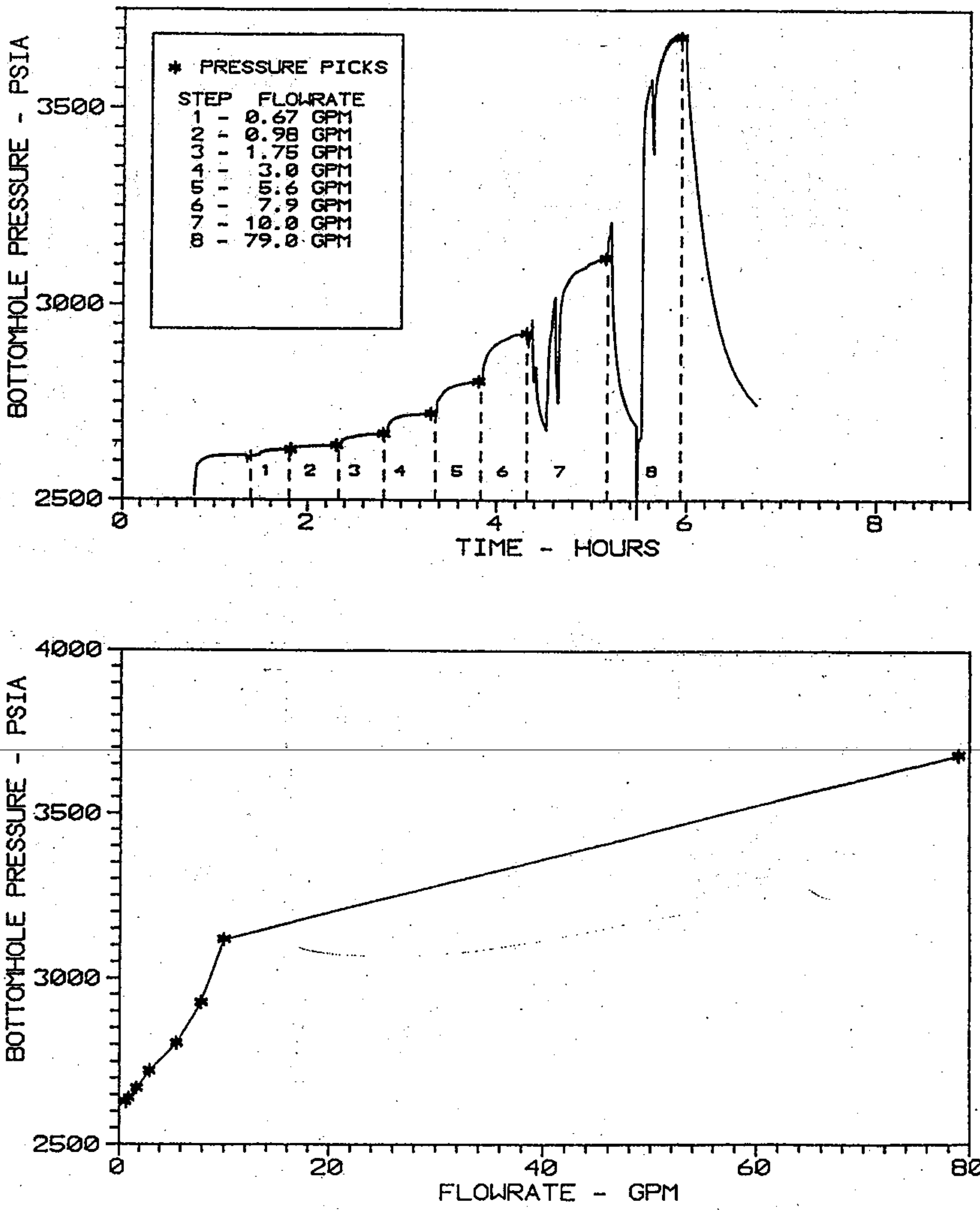


FIGURE 5
STEP RATE TEST #3
ARISTECH CHEMICAL CORPORATION
WATER DISPOSAL WELL #3
MARCH 25, 1991

Gauge at 5441 ft. (vertical) subsurface

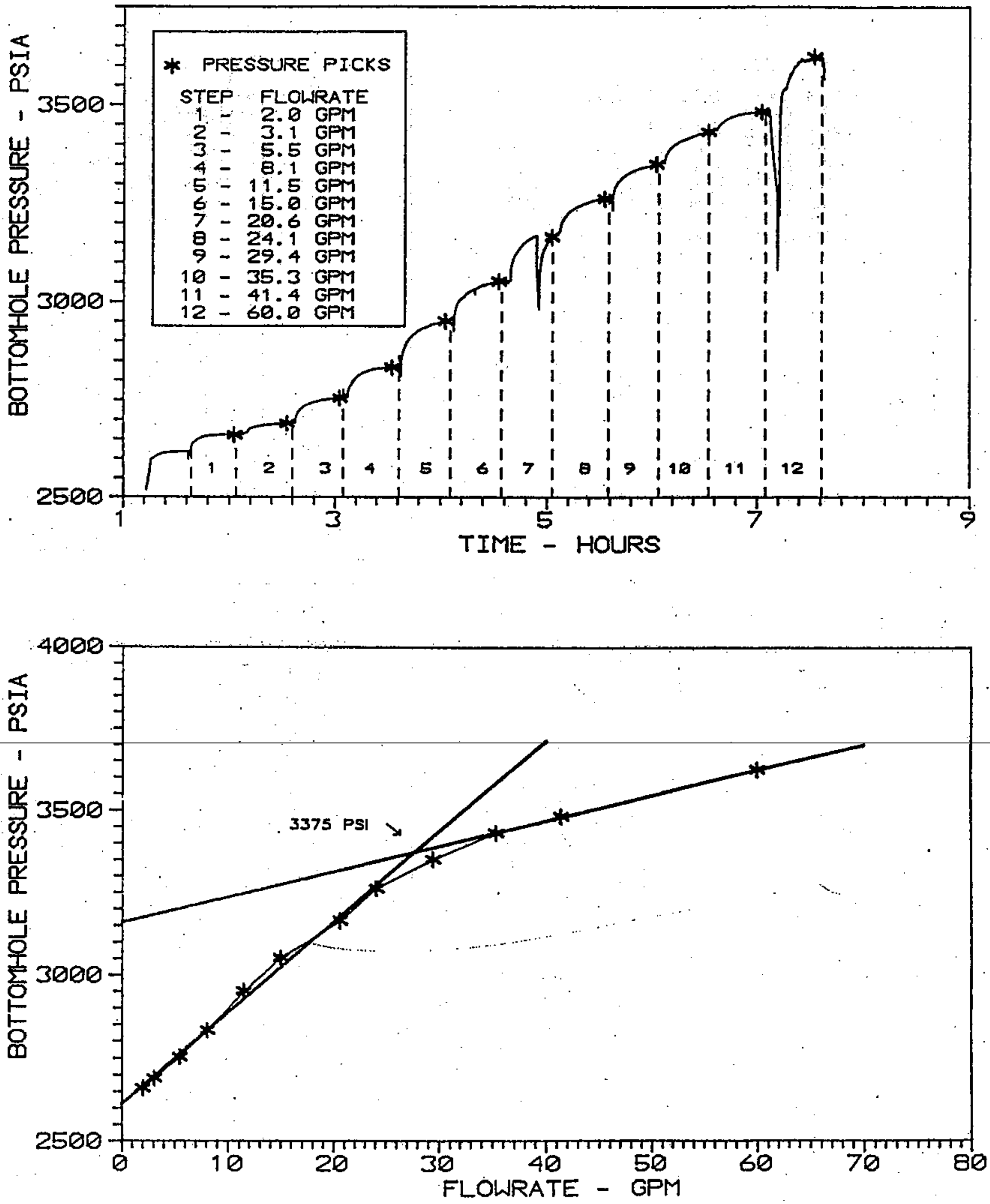
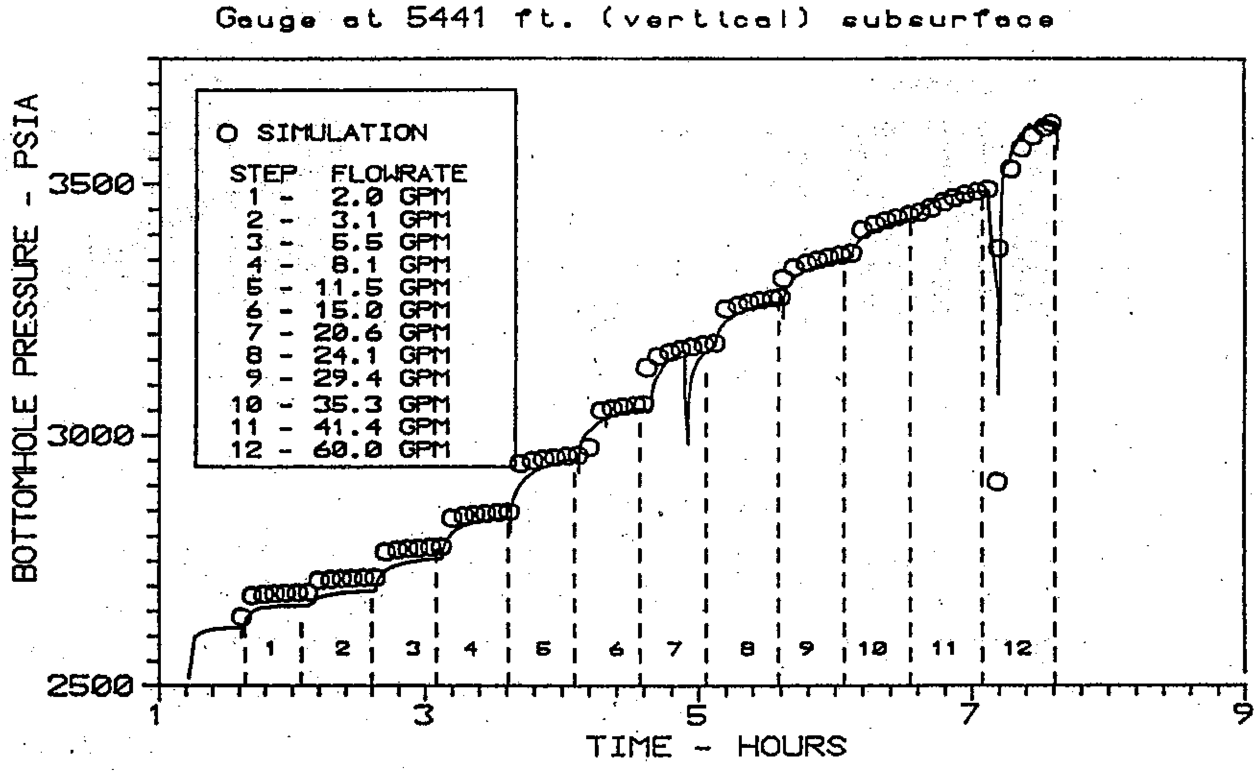


FIGURE 6
STEP RATE TEST #3
ARISTECH CHEMICAL CORPORATION
WATER DISPOSAL WELL #3
MARCH 25, 1991



In-Situ Stress Measurement Data Summary (Monitor Well)

Table 1

Test Identification	Formation Name	Interval Depth (BGL) (ft)	Date Start 1st Inj.	Time +/-1 min.	Lithology/Description
Reference	Mt. Simon	(ft)	–	–	Sandstone
Z1	Rome	5386-5390	5/31/91	12:33	Dolomite w/Shale
Z25	Rome	5379-5383	6/4/91	05:37	Dolomite w/Shale/Fracs
Z2	Rome	5373-5377	5/31/91	16:34	Dolomite
Z3	Rome	5360-5364	5/31/91	19:12	Dolomite w/Shale/Sandstone
Z4	Rome	5315-5319	5/31/91	23:27	Dolomite w/Healed Fracs
Z5	Rome	5241-5245	6/1/91	02:59	Shaly Dolomite
Z6	Rome	5198-5202	6/1/91	06:41	Dolomite w/Shale/Fracs/Vugs
Z7	Conasauga	5174-5178	6/1/91	08:21	Dolomite w/Shale
Z26	Conasauga	5142-5152	6/4/91	16:39	Shale
Z8	Conasauga	5117-5121	6/1/91	12:03	Shale
Z9	Conasauga	5068-5072	6/1/91	17:57	Shale/Dolomite w/Fracs
Z10	Copper Ridge (Knox)	4975-4979	6/1/91	21:49	Dolomite
Z11	Copper Ridge (Knox)	4821-4825	6/2/91	10:10	Dolomite
Z27	Copper Ridge (Knox)	4623-4633	6/4/91	21:18	Dolomite
Z12	Copper Ridge (Knox)	4472-4476	6/2/91	14:56	Dolomite w/Vugs/Fracs
Z13	Copper Ridge (Knox)	4255-4259	6/2/91	16:26	Dolomite
Z14	Rose Run (Knox)	4210-4214	6/2/91	22:50	Sandstone
Z15	Rose Run (Knox)	4194-4198	6/3/91	00:13	Limestone/Chert
Z16	Rose Run (Knox)	4186-4190	6/3/91	01:41	Sandstone
Z17	Beekmantown (Knox)	4174-4178	6/3/91	04:43	Dolomite/Shale
Z18	Beekmantown (Knox)	4160-4164	6/3/91	05:48	Dolomite
Z19	Beekmantown (Knox)	4140-4144	6/3/91	08:43	Dolomite
Z20	Beekmantown (Knox)	4121-4125	6/3/91	10:11	Dolomite
Z28	Beekmantown (Knox)	4050-4060	6/5/91	01:29	Dolomite w/Shale
Z21	Beekmantown (Knox)	3970-3974	6/3/91	13:28	Dolomite
Z22	Wells Creek	3900-3904	6/3/91	17:00	Dolomite/Limestone
Z23	Black River	3780-3784	6/3/91	20:51	Limestone
Z24	Black River	3548.5-3552.5	6/4/91	00:04	Limestone w/Fracs

Aristech Chemical Corporation Haverhill Plant
In-Situ Stress Measurement Data Summary (Monitor Well)

Table 2

Test Identification	Formation Name	Rate (GPM) +/- ≈ 7%	Packer Set (PSI)	Injection Gauge Depth (ft)	Pp (PSI)	Pp (PSI/FT)
Reference	Mt. Simon	--	--	5546***	2633***	0.475***
Z1	Rome	2.1-4+	1000	5377	2560	0.483
Z25	Rome	2.30	595	5370	2543	0.474
Z2	Rome	2.30	850	5364	2609	0.486
Z3	Rome	2.30	750	5351	2585	0.483
Z4	Rome	2.30	500	5306	2568	0.484
Z5	Rome	2.30	650	5232	2523	0.482
Z6	Rome	2.40	900	5189	2501	0.482
Z7	Conasauga	2.40	775	5165	2489	0.478
Z26	Conasauga	7.00	630	5133	2473	0.482
Z8	Conasauga	2.30	650	5108	2464	0.482
Z9	Conasauga	2.50	850	5059	2427	0.48
Z10	Copper Ridge (Knox)	2.40	750	4966	2373	0.478
Z11	Copper Ridge (Knox)	2.40	520	4812	2320	0.482
Z27	Copper Ridge (Knox)	6.90	580	4614	2217	0.48
Z12	Copper Ridge (Knox)	2.40	700	4463	2157	0.483
Z13	Copper Ridge (Knox)	2.30	745	4246	2045	0.482
Z14	Rose Run (Knox)	2.30	400	4201	2009	0.478
Z15	Rose Run (Knox)	2.30	675	4185	1999	0.478
Z16	Rose Run (Knox)	2.40	640	4177	1991	0.477
Z17	Beekmantown (Knox)	2.40	675	4165	1986	0.477
Z18	Beekmantown (Knox)	2.30	660	4151	1976	0.476
Z19	Beekmantown (Knox)	2.50	520	4131	1970	0.477
Z20	Beekmantown (Knox)	2.50	670	4112	1954	0.475
Z28	Beekmantown (Knox)	7.00	680	4041	1920	0.475
Z21	Beekmantown (Knox)	2.50	520	3961	1893	0.478
Z22	Wells Creek	2.40	670	3891	1859	0.478
Z23	Black River	2.50	520	3771	1796	0.476
Z24	Black River	2.40	465	3539.5	1678	0.474

*** Data from 1968 DST

Aristech Chemical Corporation Haverhill Plant
In-Situ Stress Measurement Data Summary (Monitor Well)

Table 3

Test Identification	Formation Name	Injection Gauge Depth (ft)	P I		P o		P E	
			(PSI)	(PSI/FT)	(PSI)	(PSI/FT)	(PSI)	(PSI/FT)
Reference	Mt. Simon	–	–	–	–	–	–	
Z1	Rome	5377	4543***	.845***	–	–	3500***	.651-.730***
Z25	Rome	5370	4249	.791	–	–	3840	.715
Z2	Rome	5364	4002-4089	.746-.762	–	–	3820	.712
Z3	Rome	5351	3837	.717	–	–	3525	.659
Z4	Rome	5306	3653	.688	–	–	3375	.636
Z5	Rome	5232	4073	.778	–	–	3560	.680
Z6	Rome	5189	3880	.748	–	–	3590***	.692
Z7	Conasauga	5165	3182	.616	–	–	3075	.595
Z26	Conasauga	5133	3660	.713	–	–	>3450***	>.672***
Z8	Conasauga	5108	–	–	3924	.768	Pco = 3910	Pco = 0.765
Z9	Conasauga	5059	3347	.661	–	–	3150	.623
Z10	Copper Ridge (Knox)	4966	3150	.634	–	–	2725	.549
Z11	Copper Ridge (Knox)	4812	3286	.683	–	–	2920	.607
Z27	Copper Ridge (Knox)	4614	3361	.728	–	–	2920	.633
Z12	Copper Ridge (Knox)	4463	–	–	2860	.641	Pco = 2990	Pco = .670
Z13	Copper Ridge (Knox)	4246	2958	.700	–	–	2390	.563
Z14	Rose Run (Knox)	4201	2948	.702	–	–	2550	.607
Z15	Rose Run (Knox)	4185	–	–	4203	1.004	Pco = 4420	Pco = 1.056
Z16	Rose Run (Knox)	4177	2910	.700	–	–	2705	.648
Z17	Beekmantown (Knox)	4165	3086	.741	–	–	2725	.654
Z18	Beekmantown (Knox)	4151	2812	.677	–	–	2575	.620
Z19	Beekmantown (Knox)	4131	2771	.671	–	–	2450	.593
Z20	Beekmantown (Knox)	4112	2717	.661	–	–	2485	.604
Z28	Beekmantown (Knox)	4041	2904	.719	–	–	2460	.609
Z21	Beekmantown (Knox)	3961	2941	.742	–	–	2500	.631
Z22	Wells Creek	3891	2729	.701	–	–	2220	.571
Z23	Black River	3771	2710	.719	–	–	2145	.569
Z24	Black River	3539.5	2500	.706	–	–	2080	.588

Note *** = Significant uncertainity associated with these figures.

Aristech Chemical Corporation Haverhill Plant
In-Situ Stress Measurement Data Summary (Monitor Well)

Table 4

Test Identification	Formation Name	Shut-In Gauge Depth (ft)	ISIP (PSI)	ISIP (PSI/FT)	Interval Depth (BGL)	Approximate Formation Pressure Rise Required to Exceed Minimum Horizontal Stress (PSI)
Reference	Mt. Simon	–	–	–	–	–
Z1	Rome	5381	2650-3800***	.492-.706***	5386-5390	@ Pp = 0.48 65-1216***
Z25	Rome	5374	3455-3690	.643-.687	5379-5383	876-1112
Z2	Rome	5368	3420-3450	.637-.643	5373-5377	843-875
Z3	Rome	5355	3450-3470	.644-.648	5360-5364	878-900
Z4	Rome	5310	3225-3335	.607-.628	5315-5319	674-786
Z5	Rome	5236	3295-3385	.629-.646	5241-5245	780-869
Z6	Rome	5193	3375-3460	.650-.666	5198-5202	883-966
Z7	Conasauga	5169	3020-3055	.584-.591	5174-5178	@ Pp = 0.48 538-574
Z26	Conasauga	5137	3225-3275	.628-.638	5142-5152	760-812
Z8	Conasauga	5112	3050-3565***	.597-.697***	5117-5121	598-1109***
Z9	Conasauga	5063	2860-2925***	.565-.578***	5068-5072	430-496***
Z10	Copper Ridge (Knox)	4970	2700-2725	.543-.548	4975-4979	@ Pp = 0.47 363-388
Z11	Copper Ridge (Knox)	4816	2825-2850	.587-.592	4821-4825	563-588
Z27	Copper Ridge (Knox)	4618	2690-2820	.583-.611	4623-4633	522-651
Z12	Copper Ridge (Knox)	4467	2715-2810	.608-.629	4472-4476	616-710
Z13	Copper Ridge (Knox)	4250	2310-2335	.544-.549	4255-4259	315-336
Z14	Rose Run (Knox)	4205	2375-2410	.565-.573	4210-4214	@ Pp = 0.47 399-433
Z15	Rose Run (Knox)	4189	3250-3630***	.776-.867***	4194-4198	1282-1663***
Z16	Rose Run (Knox)	4181	2530-2575	.605-.616	4186-4190	564-610
Z17	Beekmantown (Knox)	4169	2525-2575	.606-.618	4174-4178	@ Pp = 0.47 567-617
Z18	Beekmantown (Knox)	4155	2435-2510	.586-.604	4160-4164	482-557
Z19	Beekmantown (Knox)	4135	2360-2400	.571-.580	4140-4144	418-455
Z20	Beekmantown (Knox)	4116	2340-2410	.569-.586	4121-4125	407-477
Z28	Beekmantown (Knox)	4045	2260-2350	.559-.581	4050-4060	360-449
Z21	Beekmantown (Knox)	3965	2310-2425	.583-.612	3970-3974	448-563
Z22	Wells Creek	3895	2220-2215	.570-.569	3900-3904	@ Pp = 0.47 390-386
Z23	Black River	3775	2080-2130	.551-.564	3780-3784	@ Pp = 0.47 306-355
Z24	Black River	3543.5	2025-2050	.571-.579	3548.5-3552.5	358-386

Note*** = Significant uncertainty associated with this analysis

Aristech Chemical Corporation Haverhill Plant
Drill Stem Test Data Summary
Table 5

Formation	Well	Date	Interval (ft KB)	Gauge Depth (ft KB)	P* (psi)	Note	Brine δ
Logan	Test	1/21/91	164.2-261.5	157.7	63.7	–	1.033
Berea	Test	1/29/91	679.2-734	672.7	324	–	1.095
	No. 3	4/13/89	701-751	710	333.3^1	Low Perm/ Plugged	1.03
	No. 1	5/14/68	712-733	–	–	Plugged	1.005^1
Niagran	No. 3	–	–	–	–	–	1.17
Newberg	Test	3/91	1757.4-1790.7	1750.9	837.7	–	1.097
	No. 3	–	–	–	–	–	1.2
	No. 1	5/16/68	1795-1835	1805	859	Not P*, Plugging	1.193
Beekmantown (Upper Knox)	Test	4/20/91	4009.5-4035.5	3995.5	1805.7	–	1.218
Rose Run (Knox)	Test	4/25/91	4181-4225	4170.0	1912.2	–	1.214
	No. 3	5/15/89	4503-4588	4572.0	1968.8	Deviated Well	1.19
	No. 1	5/26/68	4220-4265	4230.0	1895.6^1	–	1.199
Copper Ridge (Lower Knox)	Test	5/8/91	4446.7-4480	4440.2	2078.2	–	1.20
Mt. Simon	No. 3	9/25/89	5978-6109	5965	2645.9	Deviated Well	1.05^2
	No. 1	6/5/91 68	5520-5565	5545	2633	–	1.225
Lower Mt. Simon	No. 1	6/6/91 68	5575-5617	5613	—	No Perm.	–

Notes: 1 - not representative value; insufficient sample/shut-in time 2 - fluid sample primarly injectate

P 4-91

Barcode 002637

Box 35

APPENDIX I

DESCRIPTION OF FORMATION TESTING PROCEDURES

INTEROFFICE MEMO DENVER

To: Connie Walker

From: Jack Slechta

Subject: Description of a Swab/DST

Date: December 3, 1990

ATKEARNEY

Swab

A swab is a device equipped with an upward-opening check valve that is designed to fit snugly within the well casing or tubing that provides a means of removing fluid from the well when pressure is insufficient to support flow. The swab is lowered on a wire line to a point well below the surface of the fluid in the well and rapidly withdrawn to the surface, lifting above it the fluid through which it has been lowered. Removing a part of the column of accumulated fluid within it reduces the pressure within the lower end of the flow tubing or casing. This process encourages more fluid to flow rapidly in from the surrounding formation creating upward momentum of the entire column of fluid. In some cases, the swab is used simply as a mechanical lifting device for removing fluids from wells without any intention of inducing flow.

Drill Stem Test

A drill stem test is a method of testing a formation to determine its potential productivity before installing casing in a well. Incorporated in the drill stem testing tool are a packer, valves or ports which may be opened and closed from the surface, and a pressure-recording device. The tool is lowered to the bottom of the hole on a string of drill pipe and the packet set, isolating the formation to be tested from the formations above and supporting the fluid column above the packer. A port on the tool is opened to allow the trapped pressure below the packer to bleed off into the drill pipe, gradually exposing the formation to atmospheric pressure and allowing the well to produce. The well fluids may thus be sampled and inspected.

Repeat Formation Tester

The Repeat Formation Tester (RFT) tool is designed to take an unlimited number of formation pressure measurements at the surface during a single trip in the borehole. Instead of using explosives to activate the tool, the RFT tool is operated by an electrically driven hydraulic pump. The hydraulic operation provides the capability of repeated set-retract operations. RFT pressure measurements are accurate within 0.13 percent making the data applicable for pressure profiles to fluid density, fluid contacts, differential depletion, and reservoir inter-communication.

The RFT tool can also take one segregated fluid sample from a single test depth or two samples from different depths during a single trip in the borehole. When the tool is set, the body is held away from the borehole wall by a packer on one side and backup pistons on the other. A filter in the probe on the hydraulic pump greatly reduces flowline plugging. The minimum recommended hole size to use the RFT tool is 6 1/2 inches, and the standard chamber size is a 1 gallon and 2 3/4 gallon, or two 2 3/4-gallon capacity per sample.

Appendix G-2

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Box 35

REPORT OF DRILLING AND TESTING WASTE DISPOSAL WELL NO. 3

ARISTECH CHEMICAL CORPORATION
HAVERHILL, OHIO

ENVIROCORP PROJECT NO. 30-1237

JANUARY 29, 1990

PREPARED BY

ENVIROCORP SERVICES & TECHNOLOGY, INC.
SOUTH BEND, INDIANA

TABLE OF CONTENTS

TABLES

DRAWINGS

APPENDICES

1.0 INTRODUCTION

This report summarizes the construction of the Aristech Chemical Corporation Waste Disposal Well No. 3. Envirocorp Services & Technology, Inc. was contracted to construct the well.

Well No. 3 was spudded on April 7, 1989 when the cement used to set the conductor pipe was drilled out. Drilling operations were completed on October 4, 1989 when the last of the drilling equipment was removed from the wellsite. The well is currently on a suspended status, as of the date of this report, awaiting a permit to operate. A bridge plug is set inside the 7 inch protection casing, the injection tubing and packer have not been installed. A well schematic is included as Drawing 30-1237-1.

2.0 SUMMARY OF LOGGING AND TESTING RESULTS

For the sake of readability, the summary of well operations does not reference to the appendices containing the information gathered while constructing Well No. 3. The information can be found in the appendices as listed in Table No. I.

TABLE I
ARISTECH CHEMICAL CORPORATION
DISPOSAL WELL NO. 3
TABLE OF APPENDICES

APPENDIX	VOLUME	CONTENTS
A	2	Open Hole Geophysical Logs
B	3	Cased Hole Geophysical Logs and Selected Engineering Logs
C	4	Drill Stem and Swab Tests
D	4	Mud Log
E	4	Drilling and Completion Fluids
F	4	Directional Survey
G	4	Core Data - Rock Mechanics and Rock Properties
H	4	Summary of Casing and Cement
I	5	Chemical Analyses
J	5	Mechanical Integrity Geophysical Logs

The geophysical log measurements obtained from the open (uncased) hole are contained in Appendix A. Table II summarizes the logs run and the appropriate appendix. Information concerning formation porosities, indicated fluid resistivities, and apparent lithologys are obtained from the open hole logs. A Borehole Televiewer was run to obtain indications of fracturing within the strata immediately overlying the Mt. Simon injection interval.

Cased hole geophysical logs, run for evaluation of cement bonding, cement placement, and the condition of the protection casing are contained in Appendix B. Appendix B also contains logs run through the drillstring to confirm packer setting depths for the swab tests conducted during construction of the well.

Formation tests were conducted as shown in Table III. Tests No. 2 and No. 9 (conventional D.S.T.) gave indication of a permeable formation. Reservoir characteristics were calculated from the recorded pressure data. A summary of tests 2 and 9:

Test No.	Formation (test depth)	Extrapolated Reservoir Pressure (psig)	Permeability (md)	Flow Capacity (md-ft.)
2	Rose Run (4503'-4588')	2010.8	22.72	340.83
9	Mt. Simon (5978'-6109')	2645.9	1.63	212.13

Further details are contained in Appendix C. Tests No. 4, No. 6, No. 7, and No. 9 (swab tests) also gave indication of permeable formations (Test No. 9 was a combination conventional D.S.T. and swab test).

The swab tests were conducted for the purpose of obtaining a representative sample of fluids contained within the formation tested. The mechanical nature of the test procedure precluded obtaining any reservoir data other than producing bottom hole pressure while swabbing. Appendix C also contains the swab test summaries. Three tests, No. 1, No. 3, and No. 5 gave indication of non-permeable formations. Test No. 8 was inconclusive due to mechanical problems.

The formation fluid samples obtained were split with the Ohio Environmental Protection Agency and analyzed by independent laboratories. The complete laboratory results are found in Appendix I; the summary of analytical results are found in Table VI.

A mud logger was employed to analyze the drill cuttings circulated from the hole during the drilling operation. A final mud log is included as Appendix D. Appendix E contains information on the drilling fluid. A conventional bentonite base drilling fluid was utilized throughout the construction of the well until the protection casing was set. The Mt. Simon injection interval was cored in it's entirety using a salt-polymer system. The salt-polymer mud was employed to minimize formation damage.

TABLE II

ARISTECH CHEMICAL CORPORATION

DISPOSAL WELL NO. 3

SUMMARY OF GEOPHYSICAL LOGGING

SUITE NO.	DATE(S)	LOG RUN	DEPTH LOGGED	APPENDIX	REMARKS
1	4/11/89	Induction	SFC - 880'	A-5	--
		Sonic	SFC - 880'	A-2	--
		Caliper	SFC - 880'	--	--
		Gamma Ray	SFC - 880'	A-5	--
1A	4/14/89	R.F.T. (summary)	SFC - 880'	A-8	Repeat formation tester sample recovered was split with O.E.P.A.
ENG	4/16/89	TEMP	SFC - 780'	B-1	Temperature log to evaluate cement placement. Note: Eng = Engineering Log, See note below (*).
2	4/18/89	CBL/VDL	98' - 877'	B-2	Cement bond log with variable density.
ENG	4/24/89 - 5/26/89	Survey		F	Wellbore direction and deviation measurements.
ENG	6/7/89	GR/Neutron with CCL	SFC - 4590'	B-14	Verify packer setting depth. (Gamma Ray/Neutron with casing collar locator).
3	6/17/89	DLL/MSFL	SFC - 5852'	A-4	Dual latherolog
		LDT/CNL	SFC - 5852'	A-1	Litho-density/compensated neutron
		DI/SP/GR	SFC - 5852'	A-5	Dual induction/spontaneous potential/Gamma Ray
		Cyberlook	875' - 5852'	A-3	
ENG	6/19/89	GR-CCL	SFC -	B-15	Verify packer setting depth.
ENG	7/13/89	GR - CCL	SFC - 1800'	B-16	Verify packer setting depth.
ENG	7/17/89	GR - CCL	SFC - 1500'	B-17	Verify packer setting depth.
4	8/7/89 - 8/15/89	DLL/MSFL	5620' - 5925'	A-4	Due to severe hole problems, logging was not completed until 8/15/89.
		LDT/CNL	5610' - 5950'	A-1	
		Sonic	SFC - 5957'	A-2	
		BHT	4000' - 5950'	A-7	BHT = Borehole Televiewer
		Directional Survey	800' - 5908'	A-6	
		CBL/VDL	65' - 790'	B-3	Relogged surface casing
		Cyberlook	5700' - 5900'	A-3	
ENG	8/20/89	Temp.	SFC - 3000'	NI	Locate top of cement
ENG	8/22/89	CBL/VDL	2000' - 3030'	NI	Evaluate cement
		CET	2000' - 3030'	NI	

TABLE II (CONTINUED)
ARISTECH CHEMICAL CORPORATION
DISPOSAL WELL NO. 3
SUMMARY OF GEOPHYSICAL LOGGING

SUITE NO.	DATE(S)	LOG RUN	DEPTH LOGGED	APPENDIX	REMARKS
ENG	8/27/89	CBL/VDL	2200' - 5950'	B-4	Evaluate cement
		CET	2200' - 5950'	B-5	
ENG	8/28/89	Temp.	SFC - 3274'	NI	Evaluate annular injection procedure
ENG	8/30/89	CBL/VDL	SFC - 5950'	B-6	Evaluate cement
		CET	SFC - 5950'	B-7	
5	9/11/89 - 9/12/89	CBL/VDL	SFC - 5950'	B-10	
		CET	SFC - 5950'	B-11	CET = cement evaluation tool
		ETT-D	SFC - 5950'	NI	ETT = Electromagnetic Thickness (casing inspection)
		Temp.	SFC - 5950'	B-8	
		MFC	SFC - 5950'	B-9	MFC = Multi-Finger Caliper
6	9/20/89	DLL	5880' - 6088'	A-4	
		Sonic	5880' - 6092'	A-2	Sonic log has been computer processed
		LDT/CNL	5880' - 6088'	A-1	
		Cyberlook	5880' - 6088'	A-3	
7	9/28/89	ETT-D	20' - 6006'	B-9	Base log for future reference
		ETT-D Quicklook	850' - 6006'	B-10	

* NOTE: Engineering logs run for field evaluation of operations are not always distributed as final copies.

NI = not included

TABLE III

ARISTECH CHEMICAL CORPORATION

DISPOSAL WELL NO. 3

SUMMARY OF DRILL STEM TESTS

TEST NO.	APPENDIX	TEST INTERVAL	TEST TYPE	RECOVERY
1	C1	701' - 751' (Berea)	Conventional	No recovery.
2	C2	4503' - 4588' (Rose Run)	Conventional	Recovered 1020' (10.0 bbls.) fluid in drillpipe.
3	C3	5598' - 5733' (Rome/Conasauga)	Conventional	Recovered 2 gallons from sampler.
4	C4	4491' - 4591' (Rose Run)	Swab Test	Recovered 188 bbls. formation fluid.
5	C5	4171' - 4232' (St. Peter)	Swab Test	Recovered load fluid only, no formation fluid.
6	C6	1788' - 1858' (Newburg)	Swab Test	Recovered 93.7 bbls. formation fluid.
7	C7	1500' - 1570' (Bass Islands - "Niagaran")	Swab Test	Recovered 87.3 bbls. formation fluid with trace oil.
8	C8	5963' - 6109' (Mt. Simon)	Conventional	Misrun, No test.
9	C9	5978' - 6109' (Mt. Simon)	Conventional & Swab	Recovered 127.0 bbls. formation fluid.

TABLE IV
ARISTECH CHEMICAL CORPORATION
DISPOSAL WELL NO. 3
SUMMARY OF CORE RECOVERY

Core No.	Depths Cut Measured Depth, Ft.	Amount Cut (Ft.)	Amount Recovered (Ft.)	Remarks
1	5600-5654	54	54	Conasauga/Rome Confining Interval
2	5654-5695	41	41	Conasauga/Rome Confining Interval
3	5695-5733	38	38	Conasauga/Rome Confining Interval
4	5915-5973	58	29	Severe Hole Problems Prior To Coring
5	5973-5978	5	3	Two Trips With Core Possible Top of Mt. Simon @ 5981.
6	5982-6027	45	45	Tentative Top Mt. Simon Porosity @ 6011.5 Ft.
7	6027-6073	46	46	
8	6073-6097	24	24	Granite "Basement" @ 6079 Ft. Measured
9	6097-6109	12	12	Total Depth 6109 Ft.

TABLE V
ARISTECH CHEMICAL CORPORATION
DISPOSAL WELL NO. 3
SUMMARY OF MEASURED ROCK MECHANICAL PROPERTIES
(REFERENCE APPENDIX NO. G-1)

Measured Depth	Closure Gradient (PSI/FT) (2)	True Vertical Depth (3)	(2)*(3) Closure Pressure (PSI)	Hydrostatic Pressure At Depth-Fresh Water	Closure Pressure At Surface-Fresh Water
5678	0.871	5252	4574.5	2310.9	2263.6
5708	0.912	5279	4814.4	2322.8	2491.6
5709	0.920	5280	4857.6	2323.2	2534.4

The well was drilled directionally to a bottom hole location that is approximately 1695 feet North and 1116 feet East of the surface location at a measured depth of 6109 feet. A copy of the directional survey information is included as Appendix F.

Cores were cut from measured depths of 5600 feet to 5733 feet, 5915 feet to 5978 feet and 5982 feet to 6109 feet. Table IV summarizes the core recovery. Appendix G-2 contains details of the Rome/Conasauga cores and Appendix G-3 contains the Mt. Simon core information. In addition, mechanical rock properties were measured on three samples as summarized in Table V. A detailed report on the determination of the rock mechanical properties is included in Appendix G-1.

The surface casing, 10-3/4" 40.5 lb/feet K-55 with short thread and coupling, was set at 883 feet and cemented to surface with 475 sacks of cement. Appendix H-1 contains the O.D.N.R. Record of Casing, Cementing and Mudding as well as the treatment report supplied by the cement contractor. The protection casing, 7" 26 lb/ft. K-55 with long thread and coupling, was set at 5978 feet. The bottom two joints of protection casing were MN-80 grade for corrosion resistance. After cementing the first stage with 467 sacks "Lite Poz" (yield 2.26 cu.ft./sack) and tailing in with 170 sacks Class A (yield 1.18 cu.ft./sack), the staging collar was opened in preparation for cementing the second stage. It was not possible to circulate through the stage collar with mud returns to surface and the second stage cement was aborted. Appendix H-2 contains the report on cementing equipment installed on the protection casing as well as the installation summary. Thickening time and compressive strength tests were performed on the cement blend proposed for the protection casing. The test results are contained in Appendix H-3.

Mechanical Integrity Testing (MIT) included various unofficial pressure tests of the protection casing. An official annular test is to be performed subsequent to installation of the injection tubing. Results of the Oxygen Activation Log run as a part of the MIT are contained in Appendix J-1. Appendix J-2 contains the Radioactive Tracer (RAT) survey.

TABLE VI

ARISTECH CHEMICAL CORPORATION

DISPOSAL WELL NO. 3

SUMMARY OF CHEMICAL ANALYSES

	Formations:	Berea/ Cuyahoga	Rose Run #1	Rose Run #2	Niagaran (Bass Isl.)	Newburg	Mt. Simon
	Depths: (feet)	195 722	4503 4588	4491 4591	1500 1570	1788 1858	5978 6109
Tests	**Units**						
Sodium	mg/L	9,900	46,500	44,600	42,500	42,700	14,000
Potassium	mg/L	96	3,700	3,330	1,210	1,430	421
Calcium	mg/L	3,000		38,500	36,400	38,700	2,850
Magnesium	mg/L	730	4,900	6,070	8,970	9,150	424
Temperature	°C			24.6	23.0		21.8
Barium	mg/L	9.2	2.5	1.8	1.1	1	<0.1
Alkalinity (to pH 8.3)	mg/L			<1	<1	<1	1,430
Alkalinity (to pH 4.5)	mg/L	33	295	129	68	640	2,170
Aluminum	mg/L	N.D.	N.D.	<1	12.9	5.4	2
pH		7.0		5.76	6.22		9.58
Specific Gravity		1.03		1.19	1.17	1.2	1.05
Specific Conductance	umohs/cm	60,000		607,000	445,000	551,000	84,400
Total Dissolved Solids	mg/L	54,000	270,000	287,000	277,000	327,000	48,400
DiMethyl Benzyl Alcohol	mg/L	N.D.	74	44	0.19^{J}	N.D.	150
Phenol	mg/L	0.0	520	400	0.14	N.D.	940
Diphenylamine	mg/L	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Alpha-Picoline	mg/L	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Total Suspended Solids	mg/L	52	945	220	337	64	1,550
Sulfate	mg/L	82	380	330	180	130	2,490
Chloride	mg/L	29,000	160,000	170,000	139,000	179,000	21,200
Nitrate Nitrogen	mg/L	N.D.	N.D.**	220	<10	<10	<10
Carbonate	mg/L	N.D.	N.D.	<1	<1	<1	1,480
Bicarbonate	mg/L	33	295	129	68	640	<1
Dissolved Oxygen	mg/L		N.D.	<0.5	5.9	<0.5	9.5
Iron	mg/L	2.7	130	60.8	122	64	15.7
Manganese	mg/L	0.5	5.8	2.35	2.3	2.9	0.4
Viscosity	cps		N.D.	3	2	3	2
Acetone	mg/L	0.4	72	210	0.11	0.024	800
Cumene Hydroperoxide	mg/L	N.D.	0.74	†	†	†	†
Acetophenone	mg/L	N.D.	6.6	6	N.D.	N.D.	35
Ammonia Nitrogen	mg/L	51	56	80.5	133	129	409
Aniline	mg/L	N.D.	N.D.	N.D.	<.02	N.D.	3.1^{J}
Total Chromium	mg/L	N.D.	N.D.**	<0.1	0.25	0.15	<0.05
Formic Acid	mg/L	1,100	180	169	<5	<5	1,335
Toluene	mg/L	1	N.D.	N.D.	0.26	0.12	11
Lead	mg/L	N.D.	35	<0.3	<0.3	<0.2	0.03

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† Cumene Hydroperoxide could not be determined due to possible degredation and impure standards.

** Matrix Interference

^{J} indicates that the value is estimated.

3.0 SUMMARY OF FIELD ACTIVITIES

The following section summarizes the field activities associated with the construction sequence performed on the Aristech Waste Disposal Well (WDW) No. 3. A detailed chronological report of the daily field activities comprises Appendix 3.0 of this document. At the appropriate times, daily mud checks were performed and the results of these tests can be found in Appendix E. As the hole was drilled directionally, gyro surveys were run periodically and various contract companies were utilized during the course of this project. Great Western Drilling Ray Resources Rig No. 7 performed the actual drilling. Eaton Well Drilling drilled the conductor well. Schlumberger ran the well logs, and Smith Directional Equipment was used to directionalize the well.

On February 2, 1989 Envirocorp (formerly Ken E. Davis Associates) personnel began the initial field work for the location of WDW No. 3 at the Aristech Chemical Corporation.

On February 9, the conductor well was drilled, cased with 16 inch casing, and cemented to the surface by Eaton Well Drilling. Approximately one month later, Ray Resources rigged up their equipment. The cement plug was located in the 16 inch conductor pipe at a depth of 77 feet. When a depth of 880 feet was reached, the Schlumberger equipment was rigged up and the Dual Induction log (DIL), Gamma Ray (GR), Sonic, and Caliper logs were run. A mud check was conducted the next day to assist in log calculation of formation resistivities. The Baker inflatable packers for the Drill Stem Test (DST) were set in place at depths of 705 feet and 755 feet, creating a 50 foot test interval. A Dowell Nitrogen Unit was utilized during the DST since the Ohio Environmental Protection Agency (EPA) requested nitrogen jetting be incorporated into the procedure. Split samples of the drilling mud were then taken in conjunction with the Ohio EPA.

On April 14, using a Repeat Formation Tool (RFT) fluid samples were taken at depths of 200 feet and 700 feet. The Cuyahoga Sandstone and the Berea Sandstone Formations are found at these depths. The Aristech laboratory analyzed these samples for total dissolved solids (TDS) and obtained a result of 35,000 ppm for the Berea Formation. Aristech's sample No. 5 registered 49,000 micro-mohs and the Ohio EPA samples No. 1 and No. 2 registered 50,000 and 60,000 micro-mohs respectively. In an attempt to acquire an additional water sample for the Ohio EPA the RFT was run for a second time to a depth of 214 feet. A build-up test was also performed at this depth. The attempt to take a grab sample at 214 feet was unsuccessful, however, a sufficient quantity of water was collected between 60 feet and 714 feet. A second build-up test was conducted and then the Steven's Casing crew ran 10 3/4 inch casing touching bottom at a depth of 879 feet.

On April 16, the casing was cemented with 475 sacks filling the casing hole annulus to the surface as witnessed by the Ohio Department of Natural Resources (ODNR). The cement was Class A with 3% Calcium Chloride having a calculated yield of 1.18 cubic feet/sack. A Schlumberger temperature log was then run from a depth of 750 feet to the surface for evaluation of the cement placement. Results of the temperature log indicated continuous cement. The casing head and blow out preventor were then set in place. The cement was drilled from 775 feet MD to 880 feet MD, the bottom of the cement. The hole was then drilled beyond this point to a depth of 945 feet MD, placing the bottom in the Ohio Brown Shale. A Cement Bond Log with Variable Density Log (CBL/VDL) was run from 878 feet to the surface and the Smith Data Directional Equipment was set up. On April 19, they started to directionalize the well. A gyro survey was run from 878 feet up to the surface. Another gyro survey, run at 1350 feet MD, determined the inclination and direction to be 7.6° N 45.3° E and the true vertical depth (TVD) to be 1348.7 feet. The gyro survey was executed again at depths of 1774 feet MD and 1836 feet MD showing an inclination and direction of 19° N 38° E.

From April 19 through May 16, 878 feet MD to 4400 feet MD, directional surveys were run repeatedly with the last of the series showing a drift angle and bearing of 32.5° N 38.5° E. The well was also reamed periodically to a diameter of 9.5 inches down to a depth of 3958 feet MD.

On May 17, the hole was drilled to a depth of 4588 feet, within the Rose Run Formation. The following day, the hole was nitrogen jetted and after the fifth cleansing, split samples for DST No. 2 were collected in cooperation with the Ohio EPA. These DST samples were representative of the area between 4503 feet MD and 4588 feet MD. Drill pipe samples were collected at a depth of 1000 feet MD and four fluid samples were collected from the sample chamber at a pH of 6.8 and a temperature of 76° F.

Drilling resumed on May 19 and at the end of six days the depth had been increased from 4575 feet MD to 5344 feet MD placing the bottom in the Knox Formation. Directional surveys were run often during this drilling episode. At 5239 feet MD and 4827 feet TVD, a gyro survey determined the inclination and direction to be 27.5° N 34° E.

Based on a review of the mud logs from Aristech's WDW No. 1 and WDW No. 2, the core point of WDW No. 3 was chosen to be at a depth of 5600 feet MD, placing it within the Conasauga Foundation. A series of these cores were taken between May 26 and May 31. Core No. 1 was cut from 5600 feet MD to 5654 feet MD (54 feet); Core No. 2 was cut from 5654 feet MD to 5695 feet MD (41 feet); and Core No. 3 was cut from 5695 feet MD to 5733 feet MD (38 feet). Each core was described, photographed, and preserved for future reference according to standard operating procedure. On the last day of coring, the mud filtrate was tested for phenol content. The concentration was less than 10 ppm.

A third DST was performed June 2 within the Rome/Conasauga formation, from 5598 feet MD to 5733 feet MD. Results of DST No. 3 indicated a virtually nonpermeable formation as only 65 feet of drilling mud (0.3 barrels) entered the drill string during the two flow periods of the test. The duration of flow period number one was 480 minutes and flow period number two was 130 minutes. After review of the DST Chart by the Ohio EPA, approval was granted to drill within 100 feet of the Mt. Simon Formation. This point was reached on June 4 at a depth of 5875 feet MD.

On June 8, packers were once again placed into the Rose Run Foundation based on a request by the Ohio EPA for additional DST samples. The packers were set at depths of 4491 feet MD and 4591 feet MD achieving a total space of 100 feet. A Gamma Ray Neutron log was run to verify these depths. The hole was then swabbed through the drill pipe from June 8 through June 13 with a total of 158 barrels of fluid having been recovered during this time interval. Twenty-one split samples were collected during Episode No. 1. After Aristech's laboratory determined that three consecutive samples had been collected which were identical with respect to temperature, pH, conductivity, and phenol concentration, 21 additional split samples were collected, Episode No. 2, in an uncontaminated atmosphere. A total of 188 barrels of fluid had been recovered during this test. A Litho Density Tool as well as a Compensated Neutron log (CNL), Dual Laterolog, Micro SFL log, and a Dual Induction log with gamma ray (GR) and Spontaneous Potential (SP) were run from the current depth of 5872 feet MD to the base of the surface casing.

On June 20, the packers were set with a 61 foot spacing having been anchored at 4171 feet MD and 4232 feet MD to test the St. Peter Formation. Gamma Ray and Neutron logs were run in addition to a Casing Collar indicator (CCL) to confirm the packer depth. Twenty-four barrels of fluid had been recovered with this test but it had been determined there was no apparent fluid entry from this formation. Fresh water was pumped into the formation in an attempt to clean the formation. This fresh water treatment resulted in failure of the bottom packer. Subsequently, swabbing was initiated and a total of 109 barrels of fluid were recovered.

Due to the poor condition of the annular mud, it became necessary to concentrate on circulating and conditioning the mud from June 23 through June 28. Excessive chlorides in the mud resulted in a high water loss and created "wall cake" in the well and increased the drag on the pipe causing it to become paralyzed. Starch, defoamer, and polymer were added to enhance circulation and increase viscosity. The pipe was finally freed and extracted after six days of conditioning.

Drilling was suspended until July 14, while procedures for further drilling were clarified between Aristech and OEPA. On July 14, the packers were set for a swab test of the interval from 1788 feet MD to 1858 feet MD, placing it within the Newburg Formation. Swabbing began and samples were taken over the course of two days with a total of 93.7 barrels of recovered fluid. Four days later, a swab test was run on the Bass Islands Group of Silurian age (referred to as the Niagaran Formation by the Ohio EPA), specifically at an interval between 1500 feet MD and 1570 feet MD, creating a 70 foot space between the packers. Swabbing resulted in 67.1 barrels of recovered fluid. Samples were taken on July 19 completing the test.

Operations resumed July 30 pursuant to agreement betweeen Aristech and OEPA. After several days of circulating and conditioning the mud with the casing point calculated at 5985 feet, coring of the Rome Foundation began on August 2. The coring started at 5915 feet MD with the core point calculated at 5985 feet MD. A 29 foot core was obtained. The hole was then reamed in its entirety which was to a depth of 5973 feet MD. An additional one foot core was retrieved after reaching a depth of 5978 feet MD. Through a review of WDW No. 1 density logs, it was suspected that the Mt. Simon Formation might have been porous at a depth of 5981 feet MD, therefore, coring was terminated. Over the course of several days, it was necessary to ream the well, 8.5 inches to 9.5 inches, prior to running the logs. On August 11, a Sonic TD-SFC, a directional survey TD-SFC, and an additional Litho Density Neutron log were run. Attempts to use a borehole televiewer failed due to an equipment malfunction. Feeling the original CBL was inconclusive, a second CBL-VDL was also run from 790 feet MD to the surface casing. The second test indicated good bonding had been achieved.

On August 16, permission to drill an additional five feet was received. These last five feet were drilled in two stages. Two feet were drilled then Tally No. 1 was taken, measuring 5975.24 feet. The last three feet were then drilled and Tally No. 2 was measured at 5973.62 feet. The geolograph was determined to be at 5983 feet MD. At this time, 158 joints of 7 inch well casing were placed into WDW No. 3. The casing was to be cemented in two stages. After cementing the first stage, the stage collar (which had been set at 3127 feet) was opened in preparation for cementing the second stage. The well could not be circulated after opening the staging tool. A temperature log was conducted indicating the top of the cement was at 2250 feet. The stage tool was closed after squeezing 50 sacks of cement through the tool. After waiting several more days, a CBL was run from 2000 feet MD to 3030 feet MD.

On August 25, cement was drilled from the stage tool and then the cement was drilled from 5719 feet MD, the top of the first stage cement (inside casing), to 5968 feet MD. A Cement Evaluation Tool (CET) was used from 5950 feet MD to the surface and indicated several voids and a possible cave-in. A CBL and a temperature survey were run from 2200 feet MD to 5950 feet MD. Additional CBL and CET logs from 5950 feet MD to the surface were run at 2200 psi. The top of the cement was confirmed to be at 2600 feet MD.

The next task was to run a one-inch tremie line into the annular space between the 10 3/4-inch and 7 inch casings. Cement was pumped through this line from a depth of 1275 feet MD to the surface. After curing several days, multiple logs were run on the cement and casing. A temperature log survey, and Electromagnetic Thickness Tool (ETT), and a CBL-VDL (no pressure) were run between the absolute bottom and the surface. A CET (no pressure) was also utilized and the 7 inch casing was pressure tested at 3000 psi.

On September 13, the drilling of the remaining cement continued as well as coring into a new formation upon reaching 6027 feet MD. A 45 foot core from the Mt. Simon formation was pulled and documented. From this description, the main porosity of Mt. Simon was picked at 6011.5 feet MD and drilling resumed. During the next several days, a 46-foot core was taken between 6027 feet MD and 6073 feet MD. A 24-foot core was taken between 6073 feet MD and 6097 feet MD, and a 12-foot core was taken from between 6097 feet MD and 6109 feet MD. The coring was completed September 20. The next day, a Laterolog, Litho Density log, and a Compensated Neutron Porosity log were run across the open hole interval.

On September 22, a borehole televiewer and sonic were utilized, a directional survey was run, and the DST on the Mt. Simon Formation was initiated. The packers were set for a test interval between 5978 feet MD and 6109 feet MD. Samples were taken on September 26 and a total of 205 barrels of fluid were recovered during the test. Two days later, an ETT was run from 5978 feet MD to the surface.

On September 30, a bridge plug was at 5884 feet and the drilling mud was inhibited against corrosion. The system was pressure tested at least three times at 3000 psi and held at 2900 psi. Dismantling the drilling equipment began and was completed October 4.

The well was reentered on November 16, 1989 to prepare for an interference test to be performed as a part of the land ban petitioning process. The bridge plug was retrieved and a packer set, on tubing, at a depth of 5941 feet. 1000 gallons of 15% HC1 acid were pumped into the Mt. Simon formation with a maximum surface treating pressure of 700 psig. After recovery of the load fluid, all three Aristech wells were equipped with necessary pressure recording equipment and the interference test was completed on November 30, 1989. Subsequent to the interference test, a step rate test was performed on Well No. 3. The results of both tests are contained and discussed in the petition document, which will be submitted upon its completion in accordance with Aristech's permit to drill.

On December 13, 1989, a Radioactive Tracer Survey (RAT) was run and an Oxygen Activation Log (OAL) was completed on the 14th. Results of both surveys gave indication that all injected fluid was entering the Mt. Simon formation with no fluid movement past the injection packer or upward outside the casing.

The packer was removed from the well and the bridge plug reinstalled, at 5941 feet. The Well was returned to a suspended status, waiting for permission to install injection tubing on December 19, 1989.

Appendix G-3

REPORT OF DRILLING AND TESTING OF THE MONITOR WELL (DEEP WELL NO. 4)

ARISTECH CHEMICAL CORPORATION
HAVERHILL, OHIO

ENVIROCORP PROJECTS NO. 30-1708 AND NO. 30-1754

P4-91

Barcode 002637

Box 35

JULY 12, 1991

PREPARED BY
ENVIROCORP SERVICES & TECHNOLOGY, INC.
SOUTH BEND, INDIANA

TABLE OF CONTENTS

FIGURE

TABLES

DRAWING

APPENDICES

1.0 INTRODUCTION

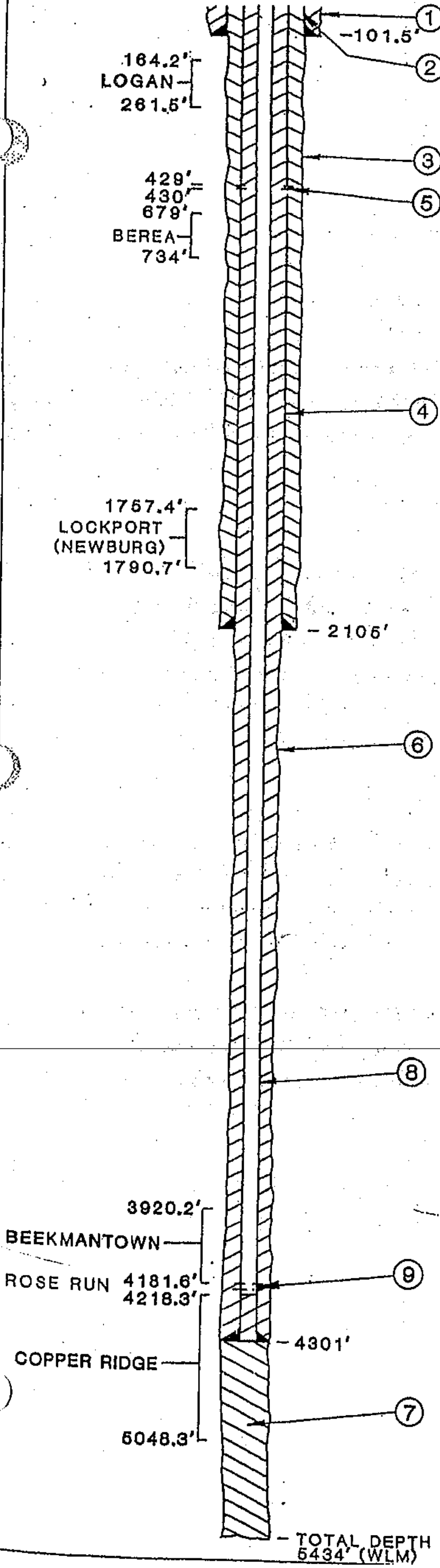
This report summarizes the construction and testing of Aristech Chemical Corporation's Monitor Well (Deep Well No. 4). Envirocorp Services & Technology, Inc. was contracted to construct the well.

The Monitor Well was constructed in accordance with the approved well plan with minor modifications as dictated by hole conditions. Any deviations to the well plan were communicated to Ohio EPA by the Aristech representative. The sampling was done as required and results of the sampling were not adversely impacted by hole conditions. All fluid samples obtained are representative of fluids contained in the formations to be tested pursuant to the well plan. The well has been perforated in the Rose Run but has not been swabbed to ensure fluid entry at this time. It is anticipated that reliable fluid and pressure information will be obtained over the life of the well in accordance with the well plan.

The Monitor Well was spudded on January 17, 1991. Seven inch casing was set at 101.5 feet below ground surface and cemented to surface. Unless otherwise noted, depths are measured from ground surface. A four inch core hole was then drilled to 2170 feet. During this initial coring operation, representative formation fluid samples were obtained from the Logan, Berea and Lockport formations. The details of the sampling events and the validated analytical results will be submitted under separate cover. The hole was reamed out to six and one half inches in diameter to a depth of 2105 feet to enable the placement of a four and one half O.D. casing in the hole. The casing was set at 2105 feet and cemented to surface in two stages.

Four inch coring continued, with representative fluid samples being collected from the Beekmantown (also known as Upper Knox), Rose Run and Copper Ridge (also known as Lower Knox). The well was cored to a total depth of 5434 feet WLM (wire line measurement). All cores from 101.5 feet to bottomhole were recovered split and stored as required by the well plan. No cores were taken in the unconsolidated alluvium or bedrock above 101.5 feet. A monitor well stratigraphic column is included as Drawing 30-1708-1. After total depth was achieved, 28 in-situ stress tests were performed for determination of fracture gradients in the formations below 3550 feet. Analysis of the in-situ stress tests are being submitted under separate cover. The well was then plugged back to a depth of 4303 feet and 2-3/8 inch monitor well casing was installed. The monitor well casing was then cemented to surface with 160 sacks of cement.

A Cement Bond Log (CBL/VDL) was run on the monitor well casing. The casing was perforated in the Rose Run Formation from 4186 feet to 4222 feet. The CBL/VDL confirmed proper cementing of the casing from bottom hole to surface. A pressure monitor was installed on June 27, 1991. A schematic of the well as completed is shown as Figure 1.0.



NOT TO SCALE

DETAILS AS CONSTRUCTED

1. 9 7/8" HOLE TO 101.5'
2. 7" O.D. 17 LB/FT H-40 FLUSH JOINT CASING (6.5" I.D.) SET AT 101.5' AND CEMENTED TO SURFACE WITH 25 SACKS OF CLASS A CEMENT AND 1 SACK SALT
3. 4" CORE HOLE REAMED TO 6 1/2"
4. 4 1/2" O.D. 10.5 LB/FT J-55 ST & C CASING SET AT 2105' GROUND LEVEL AND CEMENTED TO 454' WITH 100 SACKS OF PREMIUM CEMENT, 10.8% MICROBOND, .6% HALAD 344, 2% $CaCl_2$, 5% CFR2P, 1/4 LB FLOCELE FOLLOWED BY 175 SACKS OF PREMIUM CEMENT, 10.8% MICROBOND, .6% HALAD 344, 2% $CaCl_2$, AND .5% CFR2P. SECOND STAGE OF CEMENT FROM 454' TO SURFACE 100 SACKS OF STANDARD BULK CEMENT WITH 4% GEL AND 5 SACKS OF 5% $CaCl_2$
5. PERFORATIONS: 4 RADIAL BETWEEN 429' & 430' FOR CIRCULATION OF SECOND STAGE OF CEMENT
6. 4" CORE HOLE TO TOTAL DEPTH 5427' (5434' WLM, WIRELINE MEASUREMENT)
7. PLUGGED BACK FROM 5427' TO 4303' WITH 137.5 SACKS CLASS A CEMENT (YIELD 1.18 CUBIC FT/SACK)
8. 2 3/8" O.D. 4.6 LB/FT J-55 NON UPSET TUBING SET AT 4301' AND CEMENTED TO SURFACE WITH 110 SACKS HALIBURTON LIGHT FOLLOWED BY 50 SACKS 50/50 POZMIX
9. PERFORATIONS, 4186' TO 4222', 2 HOLES/FT

ENVIROCORP
ENVIROCORP SERVICES & TECHNOLOGY, INC.

HOUSTON, TX.
SOUTH BEND, IN
BATON ROUGE, LA.

FIGURE 1.0
ARISTECH CHEMICAL CORP.
HAVERHILL, OHIO

MONITOR WELL SCHEMATIC

DATE: 5/10/91	CHECKED BY: KCP	JOB NO: 30-1708
DRAWN BY: CRL	APPROVED BY:	DWG. NO:

2.0 SUMMARY OF LOGGING AND TESTING RESULTS

The specific information acquired while drilling the Monitor Well has been included in the attached appendices. The contents of these appendices has been listed in Table I. The appendices have been referenced where applicable instead of incorporating lengthy discussions.

TABLE I
Aristech Chemical Corporation
Monitor Well
TABLE OF APPENDICES

APPENDIX	CONTENTS
A	Open Hole Geophysical Logs
B	Cased Hole Geophysical Logs and Selected Engineering Logs
C	Drill Stem and Swab Tests
D	Core Log
E	Directional Surveys
F	Summary of Casing and Cementing
G	In-Situ Stress Test, Recorded Pressure Data
H	Core Analyses of Ohio DNR-Selected Samples

The geophysical log measurements obtained from the open (uncased) hole logging are contained in Appendix A. Table II summarizes the logs. Information concerning formation porosities, indicated fluid resistivities, and apparent lithologies can be obtained from the open hole logs.

Cased hole geophysical logs, run for evaluation of cement bonding and cement placement are contained in Appendix B. Selected engineering logs are also contained in Appendix B.

Drill Stem Test (DST) and Swab Tests were conducted as shown in Table III. Further details are contained in Appendix C.

The swab tests were conducted for the purpose of obtaining a representative sample of fluids contained within the formation tested. Appendix C also contains the swab test summaries. A summary of the chemical analytes from the representative samples is included as Table V. Further information concerning the analyses is contained in the analytical report, submitted under separate cover.

In-situ stress testing was performed for the determination of fracture gradients. Table VI summarizes the in-situ stress test intervals. The recorded pressure data for each interval tested is contained in Appendix G. Further information is contained in the Report of In-Situ Stress Testing, submitted under separate cover.

Five core samples were chosen by Ohio DNR for geophysical analyses. The results of the analyses are contained in Appendix H. Porosity and permeability were measured and petrographic analyses were done. The petrographic analyses included thin section microscopy, X-ray diffraction analyses and scanning electron microscopy.

TABLE II

Aristech Chemical Corporation

Monitor Well

SUMMARY OF GEOPHYSICAL LOGGING

Depth	Log Run	Properties Measured	Appendix	Remarks
2169' - 138'	CNL/FDC	Porosity	A.1	Measures neutron porosity and density porosity. Includes gamma ray which is the main correlating log device.
2169' - 830'	Sonic	Porosity	A.2	Measures open hole porosity. Could be used to correlate seismic reflection data.
2169' - 138'	Induction	Resistivity	A.3	Measures resistivity of formation fluids. Gives qualitative indication of permeability.
5434' - 2106'	CNL/FDC	Porosity	A.4	Measures neutron porosity and density porosity. Includes gamma ray which is the main correlating log device.
5434' - 2106'	Sonic	Porosity	A.5	Measures open hole porosity. Could be used to correlate seismic reflection data.
5434' - 2106'	Induction	Resistivity	A.6	Measures resistivity of formation fluids. Gives qualitative indication of permeability.
2108' - 138'	CBL/VDL	Sonic Device	B.1	Gives indication of cement placement and bonding. Surface casing evaluation.
1982' - Surface	Temp. Log	Temperature	B.2	Measures differences in temperature behind casing.
5360' - 5150'	CCL	Gamma Ray	B.3	Correlation log run to confirm packer depth for first in-situ stress test.
4122' - 170'	CBL/VDL	Sonic Device	B.4	Gives indication of cement placement and bonding. Monitor casing evaluation.

TABLE III

Aristech Chemical Corporation

Monitor Well

SUMMARY OF DRILL STEM TESTS AND SWAB TESTS

Test No.	Appendix	Test Interval (ft.)	Test Type	Recovery
DST 1	C.1	Logan 164.2 - 261.5	Conventional & Swab Test	Pressure Recorded 63.7 psi Recovered representative sample
DST 2	C.2	Berea 679.2 - 734	Conventional & Swab Test	Pressure Recorded 324.3 psi Recovered representative sample
DST 3	C.3	Lockport 1757.4 - 1790.7	Conventional & Swab Test	Pressure Recorded 837.7 psi Recovered representative sample
DST 4	C.4	Beekmantown 4012 - 4035	Conventional & Swab test	Pressure not Recorded Recovered representative sample
DST 4-A	C.5	Beekmantown 4006 - 4035	Conventional	Pressure Recorded 1805.7 psi
DST 5	C.6	Rose Run 4181 - 4225	Conventional & Swab Test	Pressure Recorded 1912.2 psi Recovered representative sample
DST 6	C.7	Copper Ridge 4446.7 - 4480	Conventional & Swab Test	Pressure Recorded 2078.2 psi Recovered representative sample

A continuous core was cut from a measured depth of 101.5 feet to 5434 feet. Table IV summarizes the formation intervals. The core log is included in Appendix D.

TABLE IV

Aristech Chemical Corporation

Monitor Well

SUMMARY OF FORMATION TOPS FROM CORE LOG

Measured Depth (ft.)	Formation
*	Logan
426.8	Cuyahoga
659	Sunbury
679.1	Berea
823.6	Ohio Shale
1296.5	Olentangy
1436.9	Delaware
1500	Salina
1669.8	Lockport
1879.8	Rochester
2089.9	Dayton
2156.1	Brassfield
2206.7	Cincinnati Group
3244.3	Trenton
3319.8	Black River
3845.7	Wells Creek
3920.2	Beekmantown
4181.6	Rose Run
4218.3	Copper Ridge
5048.3	Conasauga
5192.5	Rome
5434	Total Depth

* Coring began in the Logan Formation at 101.5 feet.

TABLE V
Aristech Chemical Corporation
Monitor Well
SUMMARY OF TARGET ANALYTES

- InOrganics
  - Alkalinity
  - Ammonia-Nitrogen
  - Bromide
  - Bicarbonate
  - Carbonates
  - Chloride
  - Dissolved Oxygen
  - Nitrates
  - Tot. Dissol. Solids
  - Tot. Suspnd. Solids
  - Specific Conductance
  - Specific Gravity
  - Silicates
  - Sulfates
  - Viscosity

- Metals
  - Aluminum
  - Barium
  - Calcium
  - Hex.Chromium
  - Tot.Chromium
  - Iron
  - Lead
  - Magnesium
  - Manganese
  - Potassium
  - Sodium

- Volatiles
  - Acetone
  - Toluene
  - Formic Acid

- Semi-Volatiles
  - Acetophenone
  - Alpha-Picoline
  - Aniline
  - Phenol
  - Cumene
  - DiMethylBenzylAlcohol
  - DiPhenylAmine
  - BisPhenol A

- Total Phenolics
  - Before
  - Formation
  - After

TABLE VI

Aristech Chemical Corporation

Monitor Well

IN-SITU STRESS TEST INTERVALS

Date	Test No.	Tool Spacing	Depth to M.P.P.*	Formation	Pump-in Rate, GPM	Packer Inflation Pressure
5/31/91	1	4	5388	Rome	2.1 - 4+	1000
5/31/91	2	4	5375	Rome	2.3	850
5/31/91	3	4	5362	Rome	2.3	750
5/31/91	4	4	5317	Rome	2.3	500
6/1/91	5	4	5243	Rome	2.3	650
6/1/91	6	4	5200	Rome	2.4	900
6/1/91	7	4	5176	Conasauga	2.4	775
6/1/91	8	4	5119	Conasauga	2.3	650
6/1/91	9	4	5070	Conasauga	2.5	850
6/1/91	10	4	4977	Beekmantown	2.4	750
6/2/91	11	4	4823	Beekmantown	2.4	520
6/2/91	12	4	4474	Beekmantown	2.4	700
6/2/91	13	4	4257	Beekmantown	2.3	745
6/2/91	14	4	4212	Rose Run	2.3	400
6/3/91	15	4	4196	Rose Run	2.3	675
6/3/91	16	4	4188	Rose Run	2.4	640
6/3/91	17	4	4176	Copper Ridge	2.4	675
6/3/91	18	4	4162	Copper Ridge	2.3	660
6/3/91	19	4	4142	Copper Ridge	2.5	520
6/3/91	20	4	4123	Copper Ridge	2.5	670
6/3/91	21	4	3972	Copper Ridge	2.5	520
6/3/91	22	4	3902	Wells Creek	2.4	670
6/3/91	23	4	3782	Black River	2.5	520
6/3/91	24	4	3550	Black River	2.4	465
6/4/91	25	4	5381	Rome	2.3	595
6/4/91	26	10	5147	Conasauga	7.0	630
6/4/91	27	10	4628	Beekmantown	6.9	580
6/4/91	28	10	4055	Copper Ridge	7.0	680

* Mid Point Packers

3.0 SUMMARY OF FIELD ACTIVITIES

The following section summarizes the field activities associated with the construction of the Aristech Monitor Well. Deviation surveys were run at different depths and the results are included in Appendix E. The well was drilled using a continuous coring rig. Formation fluid samples were collected during the swab tests by CH_2M Hill. The chemical analyses results from CH_2M Hill are reported in "Aristech Chemical Corporation, Haverhill Plant, UIC Monitoring Well, Formation Fluid Sampling and Analysis Report" submitted under separate cover. A detailed chronological summary of the daily field activities has been included in Section 4.0.

On January 14, 1991 Envirocorp personnel began the initial field work for the location of the Monitor Well at Aristech Chemical Corporation's Haverhill, Ohio facility.

The 7-inch casing was set at a depth of 101.5 feet and cemented to the surface. A 5-inch flush joint casing (temporary drilling protection string) was set and continuous coring of the formation began with a 94 mm core bit. Coring continued to a depth of 261.5 feet. The drill string was pulled out of the hole and Halliburton's drill stem test (DST) equipment was rigged up and run into the hole. The test interval for DST No. 1 was from 164.2 feet to 261.5 feet. After the initial portion of the DST of the Logan formation was completed, three tubing volumes of formation fluid were swabbed prior to collection of the representative sample by CH_2M Hill.

The coring continued into the Berea formation until a depth of 734.0 feet was reached. The drill string was tripped out and Halliburton's DST equipment was rigged up and run into the hole for DST and Swab Testing. At this depth DST and Swab Test No. 2 were performed over the interval 679.2 feet to 734.0 feet. Representative fluid samples were collected for chemical analysis by CH_2M Hill after three tubing volumes were swabbed.

When DST and Swab Test No. 2 was completed, the coring continued into the Lockport formation until a depth of 1790.7 feet was reached. The drill string was pulled from the hole and Halliburton's DST equipment was rigged up and run into the hole for DST and Swab Test No. 3. The interval tested was from 1757.4 feet to 1790.7 feet. During the second opening of the test assembly, three tubing volumes were swabbed and a representative sample of formation fluid was recovered for chemical analysis. Fluid samples were collected by CH_2M Hill for chemical analysis.

After the completion of DST and Swab Test No. 3, the continuous coring drill string was run back into the hole and coring resumed. Coring continued through the Rochester formation and into the Dayton formation to a depth of 2170.0 feet.

Schlumberger Logging Services rigged up to run the geophysical logs. Neutron, density, gamma ray, caliper, dual induction and sonic logs were run on the open hole from 2169.0 feet to 138.0 feet. The sonic log was run from 2169.0 feet to 830 feet. There was insufficient submergence above 830 feet for the tool to function properly.

Once the open hole geophysical logs were completed, a 6-1/2 inch bit was run into the hole and reaming began. The hole was reamed from 101.5 feet to 2105 feet.

On March 19, 1991, 48 joints of 4-1/2 inch 10.5 lb. casing was set at 2105 feet ground level. The casing was cemented with 100 sacks of premium cement containing 10.8% Microbond, 6% Halad 344, 2% $CaCl_2$, 5% CFR 2P, and 1/4 lb. of Flocele, followed by 175 sacks of premium cement, containing 10.8% Microbond, 6% Halad 344, 2% $CaCl_2$, and .5% CFR 2P. The cement did not circulate to the surface. Young Wireline Service was called to run a differential temperature log to locate the cement top.

The differential temperature log was not able to pin point the top of the cement so Schlumberger was called in to run a CBL/VDL. The top of cement was indicated at 454 feet from ground level. Halliburton was contacted to do an additional cement stage using 100 sacks of standard bulk cement with 4% gel and 5 sacks of 5% $CaCl_2$. Schlumberger perforated the 4-1/2 inch casing with four shots radially from 429 feet to 430 feet. Halliburton began pumping cement into the 4-1/2 inch casing perforations. Approximately 2 barrels of cement were circulated to the surface. After the cement was set, it was drilled out at the 430 foot level where the stage cement job had been done and at the bottom of the casing. Schlumberger was then called in to run a cement bond log on the casing (CBL/VDL). Coring resumed from 2170 feet with a 94 mm core bit on March 24, 1991.

After drilling the cement from the surface casing, coring continued to a depth of 4035 feet. The drill string was pulled out of the hole and Halliburton's drill stem test (DST) equipment was rigged up and run into the hole. The test interval for DST No. 4 was from 4006.7 feet to 4035 feet. After the initial portion of the DST of the Beekmantown formation was completed, three tubing volumes of formation fluid were swabbed prior to collection of a representative sample by CH_2M Hill. The test was rerun (DST 4A) to obtain pressure data because the clocks in the pressure recording equipment had run out during the first test.

The coring continued into the Rose Run member of the Knox formation until a depth of 4225 feet was reached. The drill string was tripped out and Halliburton's DST equipment was rigged up and run into the hole for DST and Swab Testing. DST/Swab Test No. 5 was performed over the interval 4181 feet to 4225 feet. After three tubing volumes were swabbed, representative fluid samples were collected for chemical analysis by CH_2M Hill.

After DST/Swab Test No. 5 and sample collection was completed, the coring continued into the Copper Ridge member of the Knox Group until a depth of 4480 feet was achieved. The drill string was pulled from the hole and Halliburton's DST equipment was rigged up and run into the hole for DST/Swab Test No. 6. The interval tested was from 4446.7 feet to 4480 feet. Formation fluid was swabbed until three tubing volumes were removed prior to sample collection for chemical analysis. Representative fluid samples were collected by CH_2M Hill for chemical analysis.

After the completion of DST/Swab Test No. 6 and sample collection, the continuous coring drill string was run back into the hole and coring resumed. Coring continued through the Copper Ridge formation, the Conasauga Shale and into the Rome formation to a total depth of 5434 feet below land surface.

Schlumberger Logging Services rigged up to run the geophysical logs. Neutron, density, gamma ray, caliper, dual induction and sonic logs were run on the open hole from 5434 feet to 2105 feet.

The core rig was released and a completion unit was rigged up on the well in preparation for in-situ stress testing. Using an inflatable straddle packer assembly, twenty-eight intervals were tested for the determination of fracture gradients and closure stress. Pressures recorded during the in-situ stress testing are contained in Appendix G. Analysis of the test results is contained in "Results: In-Situ Stress Measurements at the Aristech Chemical's Haverhill Facility, Research and Engineering Consultants, July 1991" submitted under separate cover. A discussion of the theory is contained in "Protocol: In-Situ Stress Measurements at the Aristech Chemical's Haverhill Facility, Research and Engineering Consultants, January 1991."

Upon completion of the in-situ stress testing, Halliburton rigged up in preparation for plugging the wellbore back to the agreed monitoring point. Using the balanced plug method, 84 sacks of Halliburton Standard cement were emplaced from total depth up to 4292 feet. After waiting for the cement to harden for 24 hours, the top of the cement plug was tagged at a depth of 4523 feet. An 18 sack plug was spotted and subsequently tagged at 4517 feet after 24 hours WOC (waiting on cement). A third plug, 35 sacks, was emplaced at 4517 feet. After reverse circulating at 4288 feet, the well was secured for a 24 hour WOC period. The third plug was tagged at a depth of 4298 feet with the work string.

On Monday, June 10, 1991, 2-3/8 inch 4.6 lb/ft J-55 non upset tubing was run into the well to serve as the monitor casing. The casing was set at 4301 feet, based upon the casing tally. Each connection was wrapped with teflon tape and torqued to 600 ft-lbs. The casing was internally hydrotested to a minimum of 4600 psi during installation. On Tuesday, June 11, the casing was cemented to surface with 110 sacks Halliburton Light cement (mixed to 12.4 lb/gal slurry weight to minimize the hydrostatic gradient) followed by 50 sacks 50/50 Pozmix. Approximately three barrels of cement slurry was circulated to surface. The well was secured for a five day WOC.

After waiting for the cement to harden, Schlumberger Well Service rigged up to run the CBL/VDL. The logging tools could not be lowered below 4131 feet and the well was logged from 4131 feet to surface. The log showed that cement had been emplaced from 4131 feet to a depth of 168 feet. A 1-1/4 inch workstring was picked up and run into the well and removed the obstruction from 4131 feet.

On Monday, June 24, 1991, the interval 4269 feet (PBTD) to 4131 feet was logged and the well was perforated from 4186 feet to 4222 feet. A tubing stop was set in the casing at a depth of 4148 feet to insure a stationary gauge depth. A pressure monitor was installed and routine and periodic pressure recording commenced on June 27, 1991.

P2-91

Barcode 002637

Box 35

APPENDIX G

IN-SITU STRESS TEST, RECORDED DATA

ARISTECH CHEMICAL CORPORATION
IN-SITU STRESS TEST TUBING TALLY

.CORRELATE TO ATLAS WIRELINE GAMMA RAY-CCL
.PUP JOINT IS LOCATED AT 5345 FT. TO 5349.5 FT.

.TOP OF PUP IS 42.99 FT. ABOVE MID POINT PACKERS
.BOTTOM OF PUP IS 38.94 FT. ABOVE MID POINT PACKERS

5345 FT+ 42.99 FT= 5387.99 FT IS MPP
5349.5 FT+ 38.94 FT= 5388.44 FT IS MPP

MID POINT PERFS (MPP) IS 5388 FT. FOR THIS TEST

* FIRST JOINT 32.30 FT, 3.85 IS ABOVE FLOOR, NET IS 28.45 FT.

TEST#	LAID DOWN TUBING <-JOINT# (LENGTH)		LENGTH OF STRING (TO MPP)	STRING ABOVE FLOOR	DEPTH OF TEST	REMARKS
1			5388.00	N.A.	5388	5/31/91
2			5388.00	13.0	5375	
3			5388.00	26.0	5362	
	1	28.45 *	5359.55			AMT IN HOLE
4	2	32.63	5326.92	10.0	5317	5/31-6/1/91
	3	30.66	5296.26			ADD PUPS
5	4	32.71	5263.55	21.0	5243	DELETE PUPS
	5	27.80	5235.75			
6	6	26.04	5209.71	9.7	5200	
7			5209.71	34.0	5176	
	7	27.15	5182.56			
	8	25.45	5157.11			
8	9	27.52	5129.59	10.6	5119	
	10	26.35	5103.24			
9	11	27.60	5075.64	5.6	5070	
	12	27.18	5048.46			
	13	26.09	5022.37			
10	14	27.07	4995.30	18.1	4977	6/1/91
	TRIP TO DOWNLOAD MEMORY GAUGES, TRIP BACK IN TO TEST					
	15	27.30	4968.00			
	16	27.75	4940.25			
	17	28.80	4911.45			
	18	26.95	4884.50			
	19	32.70	4851.80			
11	20	27.55	4824.25	1.3	4823	6/2/91
	21	32.31	4791.94			
	22	26.55	4765.39			
	23	31.15	4734.24			
	24	26.80	4707.44			
	25	27.60	4679.84			
	26	25.20	4654.64			
	27	30.45	4624.19			
	28	32.60	4591.59			

IN-SITU TEST TUBING TALLY

	29	32.70	4558.89			
	30	32.65	4526.24			
	31	32.55	4493.69	19.7	4474	
	32	32.65	4461.04			
	33	26.00	4435.04			
	34	32.45	4402.59			
	35	31.80	4370.79			
	36	32.45	4338.34			
	37	31.85	4306.49			
13	38	31.70	4274.79	17.8	4257	
14	39	32.42	4242.37	30.4	4212	
15	40	31.72	4210.65	14.7	4196	6/3/91
16			4210.65	22.7	4188	
17	41	32.32	4178.33	2.3	4176	
18			4178.33	16.3	4162	
19	42	32.33	4146.00	4.0	4142	
20			4146.00	23.0	4123	
	43	31.75	4114.25			
	44	31.75	4082.50			
	45	32.45	4050.05			
	46	26.90	4023.15			
21	47	32.42	3990.73	18.7	3972	
	48	31.30	3959.43			
22	49	32.40	3927.03	25.0	3902	
	50	31.80	3895.23			
	51	32.39	3862.84			
	52	32.51	3830.33			
23	53	31.70	3798.63	16.6	3782	
	54	31.38	3767.25			
	55	32.48	3734.77			
	56	32.47	3702.30			
	57	32.36	3669.94			
	58	31.78	3638.16			
	59	27.75	3610.41			
24	60	29.47	3580.94	30.9	3550	

TRIP IN TO RETEST ROME FORMATION

25	0		5391.85	10.9	5381	6/4/91

TRIP OUT WITH PACKERS TO CHANGE INJECTION INTERVAL FROM FOUR FEET TO TEN FEET. THE INTERVAL CHANGE RESULTS IN A NET CHANGE IN STRING LENGTH (TO MID POINT OF PACKERS) OF THREE FEET. TOTAL LENGTH OF STRING IS NOW 5391 FEET.

			5391.00			
	1	28.45	5362.55			6/4/91
	2	32.63	5329.92			
	3	30.66	5299.26			
	4	32.71	5266.55			
	5	27.80	5238.75			
	6	26.04	5212.71			
	7	27.15	5185.56			
2	8	25.45	5160.11	13.0	5147	
	9	27.45	5132.66			
	10	26.33	5106.33			

IN-SITU TEST TUBING TALLY

	11	27.65	5078.68		
	12	27.18	5051.50		
	13	26.10	5025.40		
	14	27.05	4998.35		
	15	27.60	4970.75		
	16	25.16	4945.59		
	17	27.34	4918.25		
	18	26.69	4891.56		
	19	28.79	4862.77		
	20	26.95	4835.82		
	21	31.16	4804.66		
	22	26.86	4777.80		
	23	32.40	4745.40		
	24	31.74	4713.66		
	25	32.32	4681.34		
27	26	32.31	4649.03	21.0	4628
	27	31.74	4617.29		
	28	31.74	4585.55		
	29	32.43	4553.12		
	30	26.91	4526.21		
	31	32.37	4493.84		
	32	31.30	4462.54		
	33	32.70	4429.84		
	34	27.53	4402.31		
	35	32.34	4369.97		
	36	26.58	4343.39		
	37	30.50	4312.89		
	38	32.66	4280.23		
	39	32.72	4247.51		
	40	32.66	4214.85		
	41	32.61	4182.24		
	42	32.65	4149.59		
	43	25.97	4123.62		
	44	32.39	4091.23		
28	45	31.77	4059.46	4.5	4055

TESTING COMPLETED.

P1-90

Barcode 002632

Box 30

APPENDIX I

CHEMICAL ANALYSES OF FORMATION FLUIDS

1. FORMATION TEST #1, BEREA (REFERENCE APPENDIX C-1)
2. FORMATION TEST #2, ROSE RUN (#1) (REFERENCE APPENDIX C-2)
3. FORMATION TEST #3, ROME/CONASAUGA (NO RECOVERY, NO ANALYSIS) (REFERENCE APPENDIX C-3)
4. FORMATION TEST #4, ROSE RUN (#2) (REFERENCE APPENDIX C-4)
5. FORMATION TEST #5, ST. PETER (NO RECOVERY, NO ANALYSIS) (REFERENCE APPENDIX C-5)
6. FORMATION TEST #6, NEWBERG (REFERENCE APPENDIX C-6)
7. FORMATION TEST #7, BASS ISLANDS ("NIAGARAN") (REFERENCE APPENDIX C-7)
8. FORMATION TEST #9, MT. SIMON (REFERENCE APPENDIX C-9)

Technical
Testing
Laboratories Inc.

LABORATORY ANALYSIS REPORT

ARISTECH CHEMICAL CORPORATION

Laboratory Number J0457

Respectfully
Submitted:

WDW #3 ICD LAB GRAB WATER
707 FT DEPTH

Sampled by CLIENT
Date Received 04/17/89

Date Sampled 04/14/89

ANALYSIS FOR REQUESTED METALS

PARAMETER	RESULT	MDL	UNITS	METHOD	ANALYZED DATE/TIME/ANALYST
BARIUM(Total)	9.2	0.01	MG/L	E200.7	05/04/89 18:00 MS
CHROMIUM(Total)	ND	0.025	MG/L	E200.7	05/04/89 18:00 MS
LEAD(Total)	ND	0.08	MG/L	E200.7	05/04/89 18:00 MS
IRON(Total)	2.7	0.015	MG/L	E200.7	05/05/89 18:00 MS
MANGANESE(Total)	0.5	0.004	MG/L	E200.7	05/05/89 18:00 MS
ALUMINUM(Total)	ND	0.1	MG/L	E200.7	05/05/89 18:00 MS
CALCIUM(Total)	3000	0.2	MG/L	E200.7	05/05/89 18:00 MS
MAGNESIUM(Total)	730	0.2	MG/L	E200.7	05/05/89 18:00 MS
POTASSIUM(Total)	96	0.1	MG/L	E258.1	05/05/89 12:00 DK
IUM(Total)	9900	0.02	MG/L	E273.1	05/05/89 12:00 DK

ND: Not detected at a concentration greater than or equal to the MDL - Method Detection Limit

REF: USEPA; Test Methods For Evaluating Solid Waste; SW-846,3rd Ed.;Nov,1986.

REF: USEPA; Methods For Chemical Analysis Of Water And Wastes; March,1983.

LABORATORY ANALYSIS REPORT

ARISTECH CHEMICAL CORPORATION

WDW #3 4503/4587 #6

Laboratory Number J1752

Sampled by CLIENT
Date Received 05/18/89

Respectfully
Submitted:

Date Sampled 05/17/89

ANALYSIS FOR REQUESTED METALS

PARAMETER	RESULT	MDL	UNITS	METHOD	ANALYZED DATE/TIME/ANALYST
BARIUM(Total)	1.7	0.3	MG/L	E200.7	05/26/89 12:00 MS
CHROMIUM(Total)	ND	2.5	MG/L	E200.7	05/26/89 12:00 MS
LEAD(Total)	ND	1.0	MG/L	E239.1	05/31/89 16:00 DK
COPPER(Total)	ND	1.0	MG/L	E200.7	05/26/89 12:00 MS
IRON(Total)	120	1.0	MG/L	E236.1	05/31/89 16:00 DK
MANGANESE(Total)	4.5	1.0	MG/L	E243.1	05/31/89 16:00 DK
ALUMINUM(Total)	ND	20	MG/L	E202.1	05/31/89 16:00 MS
MAGNESIUM(Total)	4800	0.02	MG/L	E242.1	05/30/89 16:00 DK
TASSIUM(Total)	3700	0.1	MG/L	E258.1	05/23/89 15:00 DK
ODIUM(Total)	47,000	0.02	MG/L	E273.1	05/30/89 16:00 DK

ND: Not detected at a concentration greater than or equal to the MDL - Method Detection Limit

REF: USEPA; Methods For Chemical Analysis Of Water And Wastes; March, 1983.

Technical
Testing
Laboratories Inc.

LABORATORY ANALYSIS REPORT

ARISTECH CHEMICAL CORPORATION

WDW #3 4503/4587 #5

Laboratory Number J1751

Sampled by CLIENT
Date Received 05/18/89

Respectfully
Submitted:

Date Sampled 05/17/89

ANALYSIS FOR REQUESTED METALS

JUL 05 1989

PARAMETER	RESULT	MDL	UNITS	METHOD	ANALYZED DATE/TIME/ANALYST
BARIUM(Total)	3.3	0.3	MG/L	E200.7	05/26/89 12:00 MS
CHROMIUM(Total)	ND	2.5	MG/L	E200.7	05/26/89 12:00 MS
LEAD(Total)	35	1.0	MG/L	E239.1	05/31/89 16:00 DK
COPPER(Total)	24	1.0	MG/L	E200.7	05/26/89 12:00 DK
IRON(Total)	140	1.0	MG/L	E236.1	05/31/89 16:00 DK
MANGANESE(Total)	7.1	0.5	MG/L	E243.1	05/31/89 16:00 DK
ALUMINUM(Total)	ND	20	MG/L	E202.1	05/31/89 16:00 MS
MAGNESIUM(Total)	5000	5.0	MG/L	E242.1	05/30/89 16:00 DK
ASSIUM(Total)	3700	10	MG/L	E258.1	05/23/89 15:00 DK
SODIUM(Total)	46,000	5.0	MG/L	E273.1	05/23/89 12:00 DK

ND: Not detected at a concentration greater than or equal to the MDL - Method Detection Limit

REF: USEPA; Methods For Chemical Analysis Of Water And Wastes; March, 1983.

Technical
Testing
Laboratories Inc.

LABORATORY ANALYSIS REPORT

ARISTECH CHEMICAL CORPORATION

WDW #3 4503/4587 #6

Laboratory Number J1752

Sampled by CLIENT
Date Received 05/18/89

Respectfully
Submitted:

Date Sampled 05/17/89

ANALYSIS FOR REQUESTED METALS

PARAMETER	RESULT	MDL	UNITS	METHOD	ANALYZED DATE/TIME/ANALYST
BARIUM(Total)	1.7	0.3	MG/L	E200.7	05/26/89 12:00 MS
CHROMIUM(Total)	ND	2.5	MG/L	E200.7	05/26/89 12:00 MS
LEAD(Total)	ND	1.0	MG/L	E239.1	05/31/89 16:00 DK
COPPER(Total)	ND	1.0	MG/L	E200.7	05/26/89 12:00 MS
IRON(Total)	120	1.0	MG/L	E236.1	05/31/89 16:00 DK
MANGANESE(Total)	4.5	1.0	MG/L	E243.1	05/31/89 16:00 DK
ALUMINUM(Total)	ND	20	MG/L	E202.1	05/31/89 16:00 MS
MAGNESIUM(Total)	4800	0.02	MG/L	E242.1	05/30/89 16:00 DK
TASSIUM(Total)	3700	0.1	MG/L	E258.1	05/23/89 15:00 DK
SODIUM(Total)	47,000	0.02	MG/L	E273.1	05/30/89 16:00 DK

ND: Not detected at a concentration greater than or equal to the MDL - Method Detection Limit

REF: USEPA; Methods For Chemical Analysis Of Water And Wastes; March, 1983.

LABORATORY RESULTS

Environmental Resources Management, Inc.

855 Springdale Drive • Exton, Pennsylvania 19341 • (215) 524-3500 • Telex 4900009249

15 November 1989

Mr. George Chada
Aristech Chemical Corporation
Room 2156
600 Grant Street
Pittsburgh, PA 15230-0250

FILE: 881-04-00-01

Dear George:

Please find enclosed with this letter the Mt. Simon Formation permit analysis report and a corrected copy of the Rose Run Formation permit analysis report.

While preparing the Mt. Simon report, Environmental Resources Management, Inc. (ERM) discovered a misinterpretation regarding the formic acid analysis on the original Rose Run permit analysis report submitted to you. The quantitative results for the two trials indicated on Lancaster Laboratories, Inc.'s (LLI) analysis report are actual sample values and are not spiked sample results. ERM has reported the formic acid results for the Rose Run and Mt. Simon samples by averaging the two trials reported by LLI. The formic acid results for the other formation samples were reported correctly.

If you need any further clarification, please do not hesitate to call me. I apologize for any inconvenience this may have caused you.

Sincerely,

David R. Blye

David R. Blye
Quality Assurance Manager

DRB/stb

Enclosures
cc: Tim Prothero-Aristech
Susan Barry-ERM

An affiliate of the Environmental Resources Management Group with offices worldwide

T-4

Aristech Rose Run Well #3 Brine Water Sample
Lancaster Laboratory Incorporated No.: WW 1400857
Date Submitted: 6/15/89

ANALYSIS	RESULT AS RECEIVED		LIMIT OF QUANTITATION	
Sodium	44,600.	mg/L	0.5	mg/L
Potassium	3,330.	mg/L	0.5	mg/L
Calcium	38,500.	mg/L	0.05	mg/L
Magnesium	6,070.	mg/L	0.05	mg/L
Temperature (Measured in the field, value reported separately)				
Barium	1.8	mg/L	0.1	mg/L
Alkalinity to pH 8.3	<1.	mg/L	1.	mg/L
Alkalinity to pH 4.5	129	mg/L	1.	mg/L
Aluminum	<1.	mg/L	1.	mg/L
pH	5.76		0.01	mg/L
Specific Gravity	1.19			
Specific Conductance	607,000.	µmhos/cm	1.	µmhos/cm
Total Dissolved Solids	287,000.	mg/L	100.	mg/L
Dimethyl Benzyl Alcohol	44.	mg/L	0.1	mg/L
Phenol	400.	mg/L	0.1	mg/L
Diphenylamine	N.D.		0.1	mg/L
Alpha-Picoline	N.D.		0.1	mg/L
Total Suspended Solids	220.	mg/L	20.	mg/L
Sulfate	330.	mg/L	50.	mg/L
Chloride	170,000.	mg/L	20.	mg/L
Nitrate Nitrogen	220.	mg/L	10.	mg/L
Carbonate	<1.	mg/L	1.	mg/L
Bicarbonate	129.	mg/L	1.	mg/L
Dissolved Oxygen	<0.5	mg/L	0.5	mg/L
Iron	60.8	mg/L	0.05	mg/L
Manganese	2.35	mg/L	0.01	mg/L
Viscosity	3.	cps	1.	cps
Acetone	210.	mg/L	1.	mg/L
Cumene Hydroperoxide*				
Acetophenone	6.	mg/L	0.1	mg/L
Ammonia Nitrogen	80.5	mg/L	0.1	mg/L
Aniline	N.D.		0.1	mg/L
Total Chromium	<0.1	mg/L	0.1	mg/L
Formic Acid **	169.	mg/L	5.0	mg/L
Toluene	N.D.		0.5	mg/L
Lead	<0.3	mg/L	0.3	mg/L

* - Cumene hydroperoxide could not be determined due to impure reference material, as well as what appeared to be degradation in the chromatographic system.

I-4

** - The reported formic acid result of 169. mg/L is an average of two trials which yielded the following results:
168. mg/L Trial #1
170. mg/L Trial #2

Additionally, the sample was spiked with 200 mg/L of formic acid and provided a recovery of 83.8%.

< - Indicates the result is less than the smallest amount which can be accurately quantitated.

N.D. - Indicates none detected.

Note: These results have been transcribed by ERM, Inc. from the Lancaster Laboratories Inc. analysis report for the Rose Run Well #3 Brine Water Sample (LLI# WW 1400857).

I-4

Environmental Resources Management, Inc.
855 Springdale Drive • Exton, Pennsylvania 19341 • (215) 524-3500

Letter of Transmittal

DATE 7-12-89
W.O. No. 881040001
ATTENTION Mr. Timothy Prothero
RE: Rose Run Well #3
Brine Water Sample
Analysis Report

TO Aristech Chemical Co.
Ironton, Ohio 45638

GENTLEMEN:

WE ARE SENDING YOU ☒ Attached ☐ Under separate cover via ________ the following items:

☐ Shop drawings ☐ Prints ☐ Plans ☐ Samples ☐ Specifications

☐ Copy of letter ☐ Change order ☐ ________

COPIES	DATE	NO.	DESCRIPTION
1	7-12-89	1	Rose Run Well #3 Brine Water Sample Analysis Report

THESE ARE TRANSMITTED as checked below:

☒ For approval ☐ Approved as submitted ☐ Resubmit ____ copies for approval

☒ For your use ☐ Approved as noted ☐ Submit ____ copies for distribution

☒ As requested ☐ Returned for corrections ☐ Return ____ corrected prints

☐ For review and comment ☐ ________

☐ FOR BIDS DUE ________ 19____ ☐ PRINTS RETURNED AFTER LOAN TO US

REMARKS

Tim,

The Temperature entry is blank, I assume this was performed in the field. Please call me with the value and I will modify and resubmitt.

Also I did not see any results for hexavalent chromium, was this cancelled. I only see results for Total chromium. Please call.

COPY TO File, Sue Barry

SIGNED: David R. Blye

If enclosures are not as noted, kindly notify us at once.

I-6

Aristech WDW #3 Newburg Formation Sample
Lancaster Laboratory Incorporated No.: WW 1413820
Date Submitted: 7/18/89

ANALYSIS	RESULT AS RECEIVED	LIMIT OF QUANTITATION
Sodium	42,700. mg/L	0.5 mg/L
Potassium	1,430. mg/L	0.5 mg/L
Calcium	38,700. mg/L	0.05 mg/L
Magnesium	9,150. mg/L	0.05 mg/L
Temperature (Measured in the field, value reported separately)		
Barium	1. mg/L	0.5 mg/L
Alkalinity to pH 8.3	<1. mg/L	1. mg/L
Alkalinity to pH 4.5	640. mg/L	1. mg/L
Aluminum	5.4 mg/L	0.1 mg/L
pH (Measured in the field, value reported separately)		
Specific Gravity	1.2	
Specific Conductance	551,000. µmhos/cm	1. µmhos/cm
Total Dissolved Solids	327,000. mg/L	40. mg/L
Dimethyl Benzyl Alcohol	N.D.	0.02 mg/L
Phenol	N.D.	0.02 mg/L
Diphenylamine	N.D.	0.02 mg/L
Alpha-Picoline	N.D.	0.02 mg/L
Total Suspended Solids	64. mg/L	7. mg/L
Sulfate	130. mg/L	50. mg/L
Chloride	179,000. mg/L	20. mg/L
Nitrate Nitrogen	<10. mg/L	10. mg/L
Carbonate	<1. mg/L	1. mg/L
Bicarbonate	640. mg/L	1. mg/L
Dissolved Oxygen	<0.5 mg/L	0.5 mg/L
Iron	64. mg/L	0.05 mg/L
Manganese	2.9 mg/L	0.2 mg/L
Viscosity	3. cps	1. cps
Acetone	0.024 mg/L	0.01 mg/L
Cumene Hydroperoxide*		
Acetophenone	N.D.	0.02 mg/L
Ammonia Nitrogen	129. mg/L	0.5 mg/L
Aniline	N.D.	0.02 mg/L
Total Chromium	0.15 mg/L	0.05 mg/L
Formic Acid	<5. mg/L	5.0 mg/L
Toluene	0.12 mg/L	0.005 mg/L
Lead	<0.2 mg/L	0.2 mg/L

* - Cumene hydroperoxide could not be determined due to impure reference material, as well as what appeared to be degradation in the chromatographic system.

< - Indicates the result is less than the smallest amount which can be accurately quantitated.

N.D. - Indicates none detected.

Note: These results have been transcribed by ERM, Inc. from the Lancaster Laboratories Inc. analysis report for the Newburg Formation sample (LLI# WW 1413820).

I-

Aristech WDW #3 Newburg Formation Sample
Lancaster Laboratory Incorporated No.: WW 1413820
Date Submitted: 7/18/89

ANALYSIS	RESULT AS RECEIVED		LIMIT OF QUANTITATION	
Sodium	42,700.	mg/L	0.5	mg/L
Potassium	1,430.	mg/L	0.5	mg/L
Calcium	38,700.	mg/L	0.05	mg/L
Magnesium	9,150.	mg/L	0.05	mg/L
Temperature (Measured in the field, value reported separately)				
Barium	1.	mg/L	0.5	mg/L
Alkalinity to pH 8.3	<1.	mg/L	1.	mg/L
Alkalinity to pH 4.5	640.	mg/L	1.	mg/L
Aluminum	5.4	mg/L	0.1	mg/L
pH (Measured in the field, value reported separately)				
Specific Gravity	1.2			
Specific Conductance	551,000.	µmhos/cm	1.	µmhos/cm
Total Dissolved Solids	327,000.	mg/L	40.	mg/L
Dimethyl Benzyl Alcohol	N.D.		0.02	mg/L
Phenol	N.D.		0.02	mg/L
Diphenylamine	N.D.		0.02	mg/L
Alpha-Picoline	N.D.		0.02	mg/L
Total Suspended Solids	64.	mg/L	7.	mg/L
Sulfate	130.	mg/L	50.	mg/L
Chloride	179,000.	mg/L	20.	mg/L
Nitrate Nitrogen	<10.	mg/L	10.	mg/L
Carbonate	<1.	mg/L	1.	mg/L
Bicarbonate	640.	mg/L	1.	mg/L
Dissolved Oxygen	<0.5	mg/L	0.5	mg/L
Iron	64.	mg/L	0.05	mg/L
Manganese	2.9	mg/L	0.2	mg/L
Viscosity	3.	cps	1.	cps
Acetone	0.024	mg/L	0.01	mg/L
Cumene Hydroperoxide*				
Acetophenone	N.D.		0.02	mg/L
Ammonia Nitrogen	129.	mg/L	0.5	mg/L
Aniline	N.D.		0.02	mg/L
Total Chromium	0.15	mg/L	0.05	mg/L
Formic Acid	<5.	mg/L	5.0	mg/L
Toluene	0.12	mg/L	0.005	mg/L
Lead	<0.2	mg/L	0.2	mg/L

* - Cumene hydroperoxide could not be determined due to impure reference material, as well as what appeared to be degradation in the chromatographic system.

< - Indicates the result is less than the smallest amount which can be accurately quantitated.

N.D. - Indicates none detected.

Note: These results have been transcribed by ERM, Inc. from the Lancaster Laboratories Inc. analysis report for the Newburg Formation sample (LLI# WW 1413820).

I-6

Aristech Rose Run Well #3 Brine Water Sample
Lancaster Laboratory Incorporated No.: WW 1400857
Date Submitted: 6/15/89

ANALYSIS	RESULT AS RECEIVED		LIMIT OF QUANTITATION	
Sodium	44,600.	mg/L	0.5	mg/L
Potassium	3,330.	mg/L	0.5	mg/L
Calcium	38,500.	mg/L	0.05	mg/L
Magnesium	6,070.	mg/L	0.05	mg/L
Temperature (Measured in the field, value reported separately)				
Barium	1.8	mg/L	0.1	mg/L
Alkalinity to pH 8.3	<1.	mg/L	1.	mg/L
Alkalinity to pH 4.5	129	mg/L	1.	mg/L
Aluminum	<1.	mg/L	1.	mg/L
pH	5.76		0.01	mg/L
Specific Gravity	1.19			
Specific Conductance	607,000.	μmhos/cm	1.	μmhos/cm
Total Dissolved Solids	287,000.	mg/L	100.	mg/L
Dimethyl Benzyl Alcohol	44.	mg/L	0.1	mg/L
Phenol	400.	mg/L	0.1	mg/L
Diphenylamine	N.D.		0.1	mg/L
Alpha-Picoline	N.D.		0.1	mg/L
Total Suspended Solids	220.	mg/L	20.	mg/L
Sulfate	330.	mg/L	50.	mg/L
Chloride	170,000.	mg/L	20.	mg/L
Nitrate Nitrogen	220.	mg/L	10.	mg/L
Carbonate	<1.	mg/L	1.	mg/L
Bicarbonate	129.	mg/L	1.	mg/L
Dissolved Oxygen	<0.5	mg/L	0.5	mg/L
Iron	60.8	mg/L	0.05	mg/L
Manganese	2.35	mg/L	0.01	mg/L
Viscosity	3.	cps	1.	cps
Acetone	210.	mg/L	1.	mg/L
Cumene Hydroperoxide*				
Acetophenone	6.	mg/L	0.1	mg/L
Ammonia Nitrogen	80.5	mg/L	0.1	mg/L
Aniline	N.D.		0.1	mg/L
Total Chromium	<0.1	mg/L	0.1	mg/L
Formic Acid **				
Toluene	N.D.		0.5	mg/L
Lead	<0.3	mg/L	0.3	mg/L

* - Cumene hydroperoxide could not be determined due to impure reference material, as well as what appeared to be degradation in the chromatographic system.

I-6

** - Formic Acid (Sample was spiked with 200 mg/L of Formic Acid and provided the following results:)

168.	mg/L Trial #1
170.	mg/L Trial #2
83.8	% Spike Recovery

< - Indicates the result is less than the smallest amount which can be accurately quantitated.

N.D. - Indicates none detected.

Note: These results have been transcribed by ERM, Inc. from the Lancaster Laboratories Inc. analysis report for the Rose Run Well #3 Brine Water Sample (LLI# WW 1400857).

I-6

Aristech WDW #3 Niagaran Formation Sample
Lancaster Laboratory Incorporated No.: WW 1414238
Date Submitted: 7/20/89

ANALYSIS	RESULT AS RECEIVED		LIMIT OF QUANTITATION	
Sodium	42,500.	mg/L	0.5	mg/L
Potassium	1,210.	mg/L	0.5	mg/L
Calcium	36,400.	mg/L	0.05	mg/L
Magnesium	8,970.	mg/L	0.05	mg/L
Temperature (Measured in the field, value reported separately)				
Barium	1.1	mg/L	0.5	mg/L
Alkalinity to pH 8.3	<1.	mg/L	1.	mg/L
Alkalinity to pH 4.5	68.	mg/L	1.	mg/L
Aluminum	12.9	mg/L	0.1	mg/L
pH (Measured in the field, value reported separately)				
Specific Gravity	1.17			
Specific Conductance	445,000.	µmhos/cm	1.	µmhos/cm
Total Dissolved Solids	277,000.	mg/L	100.	mg/L
Dimethyl Benzyl Alcohol	0.19 J	mg/L	0.02	mg/L
Phenol	0.14	mg/L	0.02	mg/L
Diphenylamine	N.D.		0.02	mg/L
Alpha-Picoline	N.D.		0.02	mg/L
Total Suspended Solids	337.	mg/L	7.	mg/L
Sulfate	180.	mg/L	50.	mg/L
Chloride	139,000.	mg/L	20.	mg/L
Nitrate Nitrogen	<10.	mg/L	10.	mg/L
Carbonate	<1.	mg/L	1.	mg/L
Bicarbonate	68.	mg/L	1.	mg/L
Dissolved Oxygen	5.9	mg/L	0.5	mg/L
Iron	122.	mg/L	0.05	mg/L
Manganese	2.3	mg/L	0.2	mg/L
Viscosity	2.	cps	1.	cps
Acetone	0.11	mg/L	0.01	mg/L
Cumene Hydroperoxide*				
Acetophenone	N.D.		0.02	mg/L
Ammonia Nitrogen	133.	mg/L	0.5	mg/L
Aniline	<0.02	mg/L	0.02	mg/L
Total Chromium	0.25	mg/L	0.05	mg/L
Formic Acid	<5.	mg/L		
Toluene	0.26	mg/L	0.005	mg/L
Lead	<0.3	mg/L	0.3	mg/L

* - Cumene hydroperoxide could not be determined due to impure reference material, as well as what appeared to be degradation in the chromatographic system.

< - Indicates the result is less than the smallest amount which can be accurately quantitated.

N.D. - Indicates none detected.

J - Indicates this value is an estimate.

Note: These results have been transcribed by ERM, Inc. from the Lancaster Laboratories Inc. analysis report for the Niagaran Formation sample (LLI# WW 1414238).

Aristech WDW #3 Niagaran Formation Sample
Lancaster Laboratory Incorporated No.: WW 1414238
Date Submitted: 7/20/89

ANALYSIS	RESULT AS RECEIVED		LIMIT OF QUANTITATION	
Sodium	42,500.	mg/L	0.5	mg/L
Potassium	1,210.	mg/L	0.5	mg/L
Calcium	36,400.	mg/L	0.05	mg/L
Magnesium	8,970.	mg/L	0.05	mg/L
Temperature (Measured in the field, value reported separately)				
Barium	1.1	mg/L	0.5	mg/L
Alkalinity to pH 8.3	<1.	mg/L	1.	mg/L
Alkalinity to pH 4.5	68.	mg/L	1.	mg/L
Aluminum	12.9	mg/L	0.1	mg/L
pH (Measured in the field, value reported separately)				
Specific Gravity	1.17			
Specific Conductance	445,000.	µmhos/cm	1.	µmhos/cm
Total Dissolved Solids	277,000.	mg/L	100.	mg/L
Dimethyl Benzyl Alcohol	0.19	J mg/L	0.02	mg/L
Phenol	0.14	mg/L	0.02	mg/L
Diphenylamine	N.D.		0.02	mg/L
Alpha-Picoline	N.D.		0.02	mg/L
Total Suspended Solids	337.	mg/L	7.	mg/L
Sulfate	180.	mg/L	50.	mg/L
Chloride	139,000.	mg/L	20.	mg/L
Nitrate Nitrogen	<10.	mg/L	10.	mg/L
Carbonate	<1.	mg/L	1.	mg/L
Bicarbonate	68.	mg/L	1.	mg/L
Dissolved Oxygen	5.9	mg/L	0.5	mg/L
Iron	122.	mg/L	0.05	mg/L
Manganese	2.3	mg/L	0.2	mg/L
Viscosity	2.	cps	1.	cps
Acetone	0.11	mg/L	0.01	mg/L
Cumene Hydroperoxide*				
Acetophenone	N.D.		0.02	mg/L
Ammonia Nitrogen	133.	mg/L	0.5	mg/L
Aniline	<0.02	mg/L	0.02	mg/L
Total Chromium	0.25	mg/L	0.05	mg/L
Formic Acid	<5.	mg/L		
Toluene	0.26	mg/L	0.005	mg/L
Lead	<0.3	mg/L	0.3	mg/L

* - Cumene hydroperoxide could not be determined due to impure reference material, as well as what appeared to be degradation in the chromatographic system.

< - Indicates the result is less than the smallest amount which can be accurately quantitated.

N.D. - Indicates none detected.

J - Indicates this value is an estimate.

Note: These results have been transcribed by ERM, Inc. from the Lancaster Laboratories Inc. analysis report for the Niagaran Formation sample (LLI# WW 1414238).

p1-90 002632
Box30
CITED

C O R E A N A L Y S I S R E S U L T S

ARISTECH CHEMICAL CORPORATION
Waste Disposal Well No.3
Scioto County, Ohio

OGS CORE # 3248

Formation: Conasauga/Rome/Mt.Simon
Coring Fluid: Water Based Mud
File No.: Envirocorp 50-1277

Date: 6-JULY-1989
Analysts: Davis

SMPLE NUMBER	DEPTH ft	PERMEABILITY FULL DIAMETER Kmax md	K90 md	Vert. md	PLUG Horiz md	Vert md	POROSITY Full Diam. %	Plug Horiz. %	Plug Vert %	GRAIN DENSITY Full Diam. gms/cc	Plug Horiz. gms/cc	Plug Vert gms/cc	LITHOLOGICAL DESCRIPTION	
1	5600-01	5.30	4.30	0.44			2.4			2.76			Sh dk gry dolc scalc lam dns frac v/frac	
2	5601-02	0.95	0.27	<0.01			1.3			2.84			Dol gry vfxln vsh scalc lam dns	
3	5602-03	*	*	2.00			2.5			2.71			Sh blk/dk gry vdolc scalc foss lam dns frac v/frac	
4	5603-04												Sh blk/dk gry dolc scalc lam dns frac v/frac TBFA	
5	5604-05												Sh blk/dk gry dol scalc lam dns frac v/frac TBFA	
6	5605-06								0.9			2.84	Dol dk gry vfxln frac v/frac	PET.SMPLE
7	5606-07												Sh blk dolc lam dns frac TBFA	
8	5607-08												Sh blk dolc lam dns frac TBFA	
9	5608-09	5.70	5.10	0.19			1.8			2.74			Sh blk vdolc dns frac v/frac	
10	5609-10												Sh blk dolc dns frac v/frac TBFA.	
11	5610-11												Sh blk dolc dns frac v/frac IBFA	
12	5611-12	0.13	0.04	<0.01			0.7			2.76			Dol dk gry vfxln vsh dns frac	
13	5612-13												Sh dk gry dolc dns frac TBFA	
14	5613-14												Sh dk gry dolc dns frac TBFA	
15	5614-15												Sh dk gry dolc dns frac TBFA	
16	5615-16												Sh dk gry dolc dns frac TBFA	
17	5616-17								2.0			2.72	Sh blk dolc dns frac	
18	5617-18												Sh dk gry dolc dns frac TBFA	
19	5618-19												Sh dk gry dolc dns frac TBFA	
20	5619-20								1.3			2.69	Sh blk dolc dns frac	
21	5620-21	*705	3.10	*647			1.8			2.86			Dol dk gry vfxln scalc vsh lam dns v/frac	
22	5621-22												Sh dk gry dolc lam v/frac TBFA	
23	5622-23								1.9			2.74	Sh blk dolc dns	PET.SMPLE
24	5623-24												Sh blk dolc dns TBFA	
25	5624-25								0.9			2.72	Sh blk dolc dns	
26	5625-26	4.00	1.50	0.20			1.8			2.80			Dol gry vfxln vsh calc lam sh lam dns v/frac	

C O R E   A N A L Y S I S   R E S U L T S

ARISTECH CHEMICAL CORPORATION
Waste Disposal Well No.3
Scioto County, Ohio

Formation: Conasauga/Rome/Mt.Simon
Coring Fluid: Water Based Mud
File No.: Envirocorp 50-1277

Date: 6-JULY-1989
Analysts: Davis

SMPLE NUMBER	DEPTH ft	PERMEABILITY FULL DIAMETER Kmax md	K90 md	Vert. md	PLUG Horiz md	Vert md	POROSITY Full Diam. %	Plug Horiz. %	Plug Vert %	GRAIN DENSITY Full Diam.	Plug Horiz. gms/cc	Plug Vert	LITHOLOGICAL DESCRIPTION	
27	5626-27												Dol gry fxln vshy scalc lam dns v/frac TBFA	
28	5627-28	1.30,	0.79	0.34			1.1			2.86			Dol dk gry fxln shy calc lam dns v/frac	
29	5628-29												Dol dk gry fxln shy calc lam dns v/frac (Rubble) TBFA	
30	5629-30								0.5			2.86	Dol dk gry fxln sshy dns v/frac	
31	5630-31												Sh gry dolc lam dns v/frac TBFA	
32	5631-32												Sh gry dolc lam dns v/frac TBFA	
33	5632-33	4.30	1.60	1.15			1.6			2.74			Sh blk dolc slty lam dns v/frac	
34	5633-34												Sh blk dolc slty lam dns v/frac TBFA	PET.SMPLE
35	5634-35	1.00	0.58	<0.01			1.5			2.79			Dol dk gry fxln vshy scalc lam dns v/frac	
36	5635-36								0.6			2.72	Sh blk sdolc dns	
37	5636-37												Sh blk sdolc dns TBFA	
38	5637-38												Sh blk sdolc dns TBFA	
39	5638-39												Sh dk gry vdolc scalc v/frac TBFA	
40	5639-40	1.38	1.20	0.38			1.6			2.82			Dol gry fxln shy calc veins lam dns v/frac	
41	5640-41	1.30	0.85	1.80			1.4			2.86			Dol gry fxln shy calc veins lam dns v/frac	PET.SMPLE
42	5641-42	0.28	0,27	<0.01			1.3			2.86			Dol gry fxln scalc lam sh lam dns v/frac	
3	5642-43								1.0			2.68	Dol gry fxln shy lam frac	
4	5643-44								0.8			2.85	Dol lt gry lam dns	
6	5644-45												Dol lt gry sdy lam v/frac TBFA	
6	5645-46								0.6			2.73	Dol dk gry vfxln vshy lam dns	
7	5646-47								0.6			2.83	Dol lt gry vfxln lam dns	
8	5647-48												Sh dk gry vdolc dns frac	
9	5648-49								1.1			2.67	Sh dk gry dolc dns	
0	5649-50								1.7			2.75	Sh dk gry dolc dns	PET.SMPLE
1	5650-51	2.70	1.20	0.06			1.5			2.72			Dol gry/dk gry vfxln vshy scalc sh lam v/frac	
2	5651-52	0.15	0.11	0.10			1.2			2.85			Dol gry fxln sh scalc lam dns v/frac	PET.SMPLE

C O R E   A N A L Y S I S   R E S U L T S

ARISTECH CHEMICAL CORPORATION
Waste Disposal Well No.3
Scioto County, Ohio

Formation: Conasauga/Rome/Mt.Simon
Coring Fluid: Water Based Mud
File No.: Envirocorp 50-1277

Date: 6-JULY-1989
Analysts: Davis

SMPLE NUMBER	DEPTH ft	PERMEABILITY FULL DIAMETER Kmax md	K90 md	Vert. md	PLUG Horiz md	Vert md	POROSITY Full Diam. %	Plug Horiz. %	Plug Vert %	GRAIN DENSITY Full Diam. gms/cc	Plug Horiz.	Plug Vert.	LITHOLOGICAL DESCRIPTION	
53	5652-53	0.22	0.05	<0.01			1.1			2.82			Dol gry fxln scalc lam sh lam dns v/frac	
54	5653-54												Sh dk gry dolc scalc lam dns frac TBFA	
55	5654-55												Sh dk gry dolc scalc lam dns frac IBFA	
56	5655-56								0.7			2.73	Sh dk gry dolc dns	
57	5656-57								2.6			2.86	Dol gry fxln pp dns	
58	5657-58								0.6			2.80	Dol gry vfxln lam sh lam dns v/frac	
59	5658-59												Dol dk gry vfxln lam vshy dns v/frac	
60	5659-60												Dol dk gry vfxln lam vshy dns v/frac TBFA	PET.SMPLE
61	5660-61								1.6			2.82	Dol gry fxln shy dns	
62	5661-62								1.7			2.87	Dol gry fxln dns	
63	5662-63												Dol gry fxln lam dns v/frac	
64	5663-64								1.3			2.79	Dol gry fxln shy dns	
65	5664-65								0.8			2.80	Dol gry vfxln lam dns	
66	5665-66	5.90	0.14	<0.01			1.1			2.79			Dol lt gry vfxln sshy scalc sh lam dns	
67	5666-67	0.96	0.28	<0.01			1.0			2.81			Dol lt gry vfxln scalc sh lam dns	
68	5667-68	*880	<0.01	*155			1.0			2.83			Dol gry vfxln calcnod sh lam v/frac	
69	5668-69	0.41	0.09	0.24			1.4			2.86			Sst mott gry fg scalc lam sh lam v/frac	
70	5669-70												Dol gry cxln lam v/frac	PET.SMPLE
71	5670-71	2.10	1.40	5.99			1.2			2.78			Dol lt gry vfxln scalc lam sh lam dns v/frac	
72	5671-72												Dol lt gry vfxln scalc lam sh lam dns v/frac	
73	5672-73												Dol lt gry vfxln scalc lam sh lam dns v/frac	
74	5673-74	0.99	0.15	<0.01			1.0			2.77			Dol gry scalc lam dns	
75	5674-75	6.70	0.49	<0.01			3.2			2.75			Sst mott gry/brn fg scalc dolc lam	
76	5675-76	0.58	0.03	<0.01			2.8			2.77			Dol mott gry/brn mxln vsdy scalc	
77	5676-77	0.34	0.06	0.22			1.4			2.77			Dol gry mxln vsdy lam sh lam dns v/frac (5677.3-78.2 Acous.Vel.)	
78	5677-78	0.17	0.04	3.45			2.8			2.79			Sst gry vfg dolc scalc lam sh lam v/frac	PET.SMPLE

C O R E   A N A L Y S I S   R E S U L T S

ARISTECH CHEMICAL CORPORATION
Waste Disposal Well No.3
Scioto County, Ohio

Formation: Conasauga/Rome/Mt.Simon
Coring Fluid: Water Based Mud
File No.: Envirocorp 50-1277

Date: 6-JULY-1989
Analysts: Davis

SMPLE UMBER	DEPTH ft	PERMEABILITY FULL DIAMETER Kmax md	K90 md	Vert. md	PLUG Horiz md	Vert md	POROSITY Full Diam. %	Plug Horiz. %	Plug Vert %	GRAIN DENSITY Full Diam. gms/cc	Plug Horiz.	Plug Vert	LITHOLOGICAL DESCRIPTION	
79	5678-79	3.00	<0.01	6.42			2.9			2.77			Sst gry fg vdolc scalc lam sh lam dns v/frac	
80	5679-80	0.08	0.07	<0.01			5.5			2.76			Sst mott gry/brn fg dolc scalc lam sh lam v/frac	
81	5680-81	0.17	0.12	0.14			4.4			2.73			Sst mott gry/brn fg dolc scalc lam sh lam	
82	5681-82	0.28	0.17	<0.01			4.9			2.73			Sst mott gry/brn fg dolc vscalc lam sh lam v/frac	
83	5682-83	0.07	0.05	<0.01			4.1			2.75			Sst mott brn vfg vdolc scalc lam	
84	5683-84	0.68	0.05	<0.01			2.5			2.73			Sst mott brn vfg dol vscalc lam (5683.9-85 Rock Mechanics)	
85	5684-85												Sst mott brn vfg dol vscalc lam	
86	5685-86	2.40	0.44	<0.01			4.7			2.71			Sst mott brn vfg vdolc lam	
57	5686-87			0.03			5.0			2.71			Sst mott brn vfg vdolc lam	
38	5687-88												Sst mott brn vfg vdolc lam frac	
9	5688-89												Sst mott brn vfg vdolc lam frac	
0	5689-90	0.66	0.19	<0.01			0.9			2.64			Sst mott brn fg sdolc calc lam	
1	5690-91	1.50	0.57	<0.01			1.8			2.75			Dol mott gry fxln sdy scalc lam sh lam	
2	5691-92	2.30	0.03	0.83			1.0			2.85			Dol wh/mott gry vfxln scalc sh lam dns v/frac	
3	5692-93	5.30	3.30	<0.01			1.0			2.83			Dol gry vfxln calc lam dns v/frac	
	5693-94	2.00	0.87	2.41			6.6			2.90			Dol wh vfxln vug pp v/frac	PET.SMPLE
	5694-95	0.14	0.07	<0.01			3.3			2.88			Dol wh vfxln calc styl vug pp v/frac	
	5695-96												Dol wh vfxln scalc styl sh lam vug pp v/frac	
	5696-97	1.60	0.19	1.38			4.5			2.89			Dol wh vfxln scalc vug pp v/frac	
	5697-98	0.13	<0.01	<0.01			1.8			2.87			Dol wh/mott wh/gry scalc svug dns	
	5698-99	0.06	0.05	<0.01			1.8			2.82			Dol wh/mott wh/gry scalc dns v/frac	
	5699-5700	0.42	0.34	0.05			1.7			2.87			Dol wh vfxln calc sh lam dns v/frac	
	5700-01	0.48	0.14	<0.01			1.4			2.88			Dol lt gry fxln scalc lam shlam styl dns	
	5701-02	0.57	0.27	0.58			2.3			2.87			Dol mott wh/gry scalc vug dns v/frac	PET.SMPLE
	5702-03												Dol lt gry fxln scalc dns v/frac (5701.9-03 Rock Mechanics)	
	5703-04												Dol lt gry fxln scalc dns v/frac	

CORP SERVICES & TECHNOLOGY, INC.

C O R E   A N A L Y S I S   R E S U L T S

ARISTECH CHEMICAL CORPORATION
Waste Disposal Well No.3
Scioto County, Ohio

Formation: Conasauga/Rome/Mt.Simon
Coring Fluid: Water Based Mud
File No.: Envirocorp 50-1277

Date: 6-JULY-1989
Analysts: Davis

SMPLE NUMBER	DEPTH	PERMEABILITY FULL DIAMETER			PERMEABILITY PLUG		POROSITY			GRAIN DENSITY			LITHOLOGICAL DESCRIPTION	
	ft	Kmax md	K90 md	Vert. md	Horiz md	Vert md	Full Diam. %	Plug Horiz. %	Plug Vert %	Full Diam. gms/cc	Plug Horiz. gms/cc	Plug Vert gms/cc		
105	5704-05	3.10	2.30	0.22			1.7			2.87			Dol lt gry vfxln calc lam dns frac v/frac	
106	5705-06	1.30	0.25	0.13			1.5			2.88			Dol lt gry vfxln calc lam dns frac v/frac	
107	5706-07												Dol lt gry vfxln calc lam sty dns frac v/frac	
108	5707-08								1.8			2.85	Dol wh vfxln sh lam dns	
109	5708-09												Dol lt gry vfxln lam dns (5708.0-09.3 Acoustic Velocity)	
110	5709-10								1.7			2.84	Dol lt gry vfxln lam dns v/frac	
111	5710-11	0.52	0.23	1.99			1.4			2.86			Dol lt gry vfxln calc lam sh lam dns v/frac	
112	5711-12	0.03	0.02	<0.01			1.6			2.87			Dol lt gry vfxln anhy calc lam sh alm dns v/frac	
113	5712-13	0.36	0.24	0.38			1.5			2.86			Dol lt gry vfxln scalc lam sh lam pp dns v/frac	
114	5713-14	0.06	0.03	<0.01			1.3			2.86			Dol lt gry vfxln calc lam sh lam dns v/frac	
115	5714-15	0.72	0.49	<0.01			1.6			2.87			Dol lt gry vfxln calc lam sh lam dns v/frac	PET.SMPLE
116	5715-16												Dol lt gry vfxln calc lam dns v/frac TBFA	
117	5716-17	0.03	0.03	<0.01			0.5			2.82			Dol lt gry vfxln calc lam styl dns v/frac	
118	5717-18	0.30	0.12	<0.01			0.8			2.84			Dol lt gry vfxln scalc lam styl dns v/frac	
19	5718-19	0.87	0.06	<0.01			2.3			2.86			Dol mott gry vfxln scalc sd inclu lam vug pp v/frac	
20	5719-20	1.70	0.04	2.54			1.4			2.87			Dol lt gry vfxln calc lam styl v/frac	
21	5720-21	0.16	0.11	0.34			1.7			2.89			Dol lt gry vfxln calc styl svug v/frac	
22	5721-22												Dol lt gry vfxln v/frac TBFA	
23	5722-23	0.02	<0.01	<0.01			0.5			2.86			Dol lt gry vfxln calc lam sh lam/sty dns v/frac	
24	5723-24	0.27	0.23	0.44			0.8			2.86			Dol lt gry vfxln scalc lam sh lam styl dns v/frac	PET.SMPLE
5	5724-25	0.20	0.19	0.22			1.0			2.82			Dol mott lt gry fxln sdy lam sh lam dns	
6	5725-26	0.15	0.04	<0.01			1.1			2.82			Dol mott gry vfxln scalc foss lam dns v/frac	
7	5726-27	0.27	0.12	0.08			1.4			2.86			Dol lt gry vfxln scalc sh lam svug dns v/frac	
	5727-28	7.00	0.36	0.21			1.3			2.86			Dol lt gry vfxln calc styl svug dns v/frac	
	5728-29	*442	0.12	* 475			1.3			2.87			Dol lt gry vfxln scalc svug dns v/frac	
	5729-30	0.13	0.12	0.22			1.8			2.87			Dol mott gry vfxln scalc sh lam styl vug v/frac	

ROCORP SERVICES & TECHNOLOGY, INC.

C O R E   A N A L Y S I S   R E S U L T S

ARISTECH CHEMICAL CORPORATION
Waste Disposal Well No.3
Scioto County, Ohio

Formation: Conasauga/Rome/Mt.Simon
Coring Fluid: Water Based Mud
File No.: Envirocorp 50-1277

Date: 6-JULY-1989
Analysts: Davis

MPLE UMBER	DEPTH	PERMEABILITY					POROSITY			GRAIN DENSITY			LITHOLOGICAL DESCRIPTION	
		FULL DIAMETER			PLUG									
	ft	Kmax md	K90 md	Vert. md	Horiz md	Vert md	Full Diam. %	Plug Horiz. %	Plug Vert %	Full Diam. gms/cc	Plug Horiz. gms/cc	Plug Vert gms/cc		
31	5730-31	7.80	2.70	0.02			2.5			2.87			Dol mott gry vfxln scalc sh lam styl vug v/frac	PET.SMPLE
32	5731-32	0.27	0.10	0.09			1.2			2.86			Dol gry vfxln scalc lam sh lam dns v/frac	

\+ - Open Vertical Fracture
\# - Sample failed during analysis
TBFA - To Broken For Analysis
PET.SMPLE - Sample Selected for X-Ray Diffraction, SEM, & Thin Section analyses

P2-90 002633 Box 31

CITED

DGS CORE # 3248

APPENDIX 4.3-H

WDW NO. 3 - ENVIROCORP CORE ANALYSES

TerraTek Core Services, Inc.®

University Research Park - 360 Wakara Way - Salt Lake City, Utah 84108 - (801) 584-2480 - TWX 910-925-5284

ENVIROCORP SERVICES & TECHNOLOGY, INC.

Well:	Aristech Chemical WDW #3	State:	Ohio	Date:	7-DEC-1989
Field:	NA	County:	Scioto	TTCS File #:	5398
Drilling fluid:	NA	Location:	NA	Elevation:	NA

FULL DIAMETER PERMEABILITY AND POROSITY

Sample Number	Depth (feet)	Permeability Horz (md)	Permeability Horz-90 (md)	Permeability Vert (md)	Porosity %	Grain Density (gm/cc)		Lithology
1	5915.0-16.0	.16	.09	.19	0.6	2.86		Dol,sl/anhy,fis
2	5916.0-17.0	.02	.01	.01	1.0	2.84		Dol
3	5917.0-18.0	.24	<.01	.25	0.7	2.85	VF	Dol,fis
4	5918.0-19.0	.04	.02	.02	0.9	2.86		Dol,sl/anhy
5	5919.0-20.0	.45	.08	.09	0.6	2.81	VF	Dol,few fis
6	5920.0-21.0	1.1	.01	.46	1.3	2.81	VF	Dol fis
7	5921.0-22.0	1.6	<.01	.64	0.7	2.84	VF	Dol,sh lam
8	5922.0-23.0	209.	.04	139.	0.7	2.86	VF	Dol,sl/anhy
9	5923.0-24.0	.05	.04	.05	1.0	2.77		Dol,sdy,sh stks
10	5924.0-25.0	1.3	.65	.70	1.3	2.78	VF	Dol,sdy,chty,fis
11	5925.0-26.0	.28+	.10	.14	0.8	2.86		Dol,sl/anhy,fis
12	5926.0-27.0	.27	.03	.19	0.8	2.85	VF	Dol,fis
13@	5927.0-28.0	.01	NA	.01	0.6	2.83		Dol,few fis
14	5928.0-29.0	5.9	.11	5.5	1.5	2.84	VF	Dol,fis
15	5929.0-30.0	10.	.05	21.	0.7	2.81	VF	Dol,sl/shy
16@	5930.0-31.0	.01	NA	.01	0.9	2.85		Dol,sl/anhy
17	5931.0-32.0	.03	.01	<.01	1.3	2.77	VF	Dol,sl/shy,chty

+ - Dehydration crack affecting permeability

VF - Vertical fracture present

@ - Plug Dean-Stark analysis - Not suitable for full diameter sampling

TerraTek Core Services, Inc.

University Research Park - 360 Wakara Way - Salt Lake City, Utah 84108 - (801) 584-2480 - TWX 910-925-5284

ENVIROCORP SERVICES & TECHNOLOGY, INC. Date: 7-DEC-1989 TTCS File #: 5398
Well: Aristech Chemical WDW #3

FULL DIAMETER PERMEABILITY AND POROSITY

Sample Number	Depth (feet)	Permeability Horz (md)	Permeability Horz-90 (md)	Permeability Vert (md)	Porosity %	Grain Density (gm/cc)		Lithology
18	5932.0-33.0	.24+	.16+	.02	1.3	2.73		Sd,dol,slty
19	5933.0-34.0	.26+	.12+	1.6	0.8	2.83	VF	Dol,anhy
20	5934.0-35.0	.11	<.01	<.01	0.6	2.82	VF	Dol,sl/shy
21	5935.0-36.0	.04	.02	<.01	1.3	2.81		Dol,sdy,few fis
22	5936.0-37.0	<.01	<.01	<.01	0.3	2.92		Dol,v/anhy
23	5937.0-38.0	.02	.01	<.01	0.3	2.91		Dol,v/anhy
24	5938.0-39.0	.05	.02	.05	0.4	2.85		Dol,sl/anhy,few fis
25	5939.0-40.0	1.9	.43	.06	0.8	2.87	VF	Dol,anhy,fis
26	5940.0-41.0	.06	.06	.21	0.4	2.86		Dol,sl/anhy,few fis
27	5941.0-42.0	.04	.01	NA	0.4	2.83		Dol,few fis
28	5942.0-43.0	.07	<.01	.01	0.7	2.83	VF	Dol,few fis
5965" Top of Lower unit	5943.0-73.0							Core Not Received
29	5973.0-74.0	.40	.06	1.1	1.1	2.82	VF	Dol,sty,fis
30	5974.0-75.0	.12+	.03	<.01	1.3	2.78		Dol,sh lam,chty
31	5975.0-76.0	10.+	3.3+	1.6	0.9	2.82	VF	Dol,sl/anhy,chty
32	5976.0-77.0	1.0	.10	.12	1.5	2.81	VF	Dol,sh lam,chty
	5977.0-82.0							Core Not Received
33	5982.0-83.0	<.01	<.01	<.01	0.4	2.84		Dol,sty
34	5983.0-84.0	.81+	<.01	<.01	0.4	2.83		Dol,sh lam
35	5984.0-85.0	.24+	.17+	.42	0.6	2.84	VF	Dol,sh lam
✓36	5985.0-86.0	.03	.02	.02	3.6	2.65 ✓		Sd,sh lam

+ - Dehydration crack affecting permeability
VF - Vertical fracture present

TerraTek Core Services, Inc.®

University Research Park - 360 Wakara Way - Salt Lake City, Utah 84108 - (801) 584-2480 - TWX 910-925-5284

ENVIROCORP SERVICES & TECHNOLOGY, INC.
Well: Aristech Chemical WDW #3

Date: 7-DEC-1989

TTCS File #: 5398

FULL DIAMETER PERMEABILITY AND POROSITY

Sample Number	Depth (feet)	Permeability Horz (md)	Permeability Horz-90 (md)	Permeability Vert (md)	Porosity %	Grain Density (gm/cc)		Lithology
37	5986.0-87.0	<.01	<.01	NA	0.2	2.80		Dol,sl/chty
38	5987.0-88.0	.02	.02	<.01	0.7	2.80		Dol,sl/sdy
39	5988.0-89.0	.45	<.01	2.1	0.3	2.78	VF	Dol,chty
40	5989.0-90.0	.05	<.01	.16	0.1	2.79		Dol,sh lam,chty
41	5990.0-91.0	<.01	.01	<.01	1.9	2.76		Sd,dol,sh lam
42	5991.0-92.0	7.1	.25	.94	2.0	2.77	VF	Sd,dol
43	5992.0-93.0	.01	.01	<.01	0.7	2.81		Dol,sdy
44	5993.0-94.0	.17+	.02	.04	0.9	2.75		Dol,sdy,shy
45	5994.0-95.0	.64+	.33+	<.01	1.5	2.76		Sd,dol
46	5995.0-96.0	.99+	.03	<.01	0.3	2.80		Dol,sh stks
47	5996.0-97.0	<.01	<.01	<.01	0.7	2.83		Dol,sl/sdy
48	5997.0-98.0	.02	<.01	.01	0.7	2.84		Dol
49	5998.0-99.0	<.01	<.01	<.01	1.4	2.76		Sd,dol,sh lam
50	5999.0-00.0	.01	<.01	.01	2.0	2.70		Sd,sl/dol,sh lam
51	6000.0-01.0	.05+	<.01	<.01	0.5	2.79		Dol,sdy,sh lam
52	6001.0-02.0	.93+	.01	<.01	1.3	2.76		Sd,dol,sh lam
53	6002.0-03.0	.54+	.38+	.03	2.6	2.66 ✓		Sd,shy,sh lam
54	6003.0-04.0	.02	.02	<.01	1.1	2.75		Sd,dol,sh stks
55	6004.0-05.0	<.01	<.01	<.01	1.8	2.78		Sd,dol,sh lam
56	6005.0-06.0	<.01	<.01	<.01	1.3	2.82		Dol
57	6006.0-07.0	.06	.02	.16	2.3	2.82		Dol,sh lam

\+ - Dehydration crack affecting permeability
VF - Vertical fracture present
@ - Plug Dean-Stark analysis - Not suitable for full diameter sampling

TerraTek Core Services, Inc.®
University Research Park - 360 Wakara Way - Salt Lake City, Utah 84108 - (801) 584-2480 - TWX 910-925-5284

ENVIROCORP SERVICES & TECHNOLOGY, INC. Date: 7-DEC-1989 TTCS File #: 5398
Well: Aristech Chemical WDW #3

FULL DIAMETER PERMEABILITY AND POROSITY

Sample Number	Depth (feet)	Permeability Horz (md)	Horz-90 (md)	Vert (md)	Porosity %	Grain Density (gm/cc)	Lithology
58@	6007.0-08.0	.02	NA	.01	3.1	2.74	Dol,sdy,chty
59@	6008.0-09.0	.01	NA	<.01	0.4	2.82	Dol,sl/sdy
60	6009.0-10.0	602.	<.01	.02	1.4	2.85 VF	Dol,sl/anhy
61	6010.0-11.0	.03	.02	.02	3.1	2.67 ✓	Sd,sl/dol,sh lam
62	6011.0-12.0	.61	.22	.05	6.5	2.65 ✓	Sd,sh lam
63	6012.0-13.0	.88	.79	.33	11.1	2.61 ✓	Sd,few sh lam
64	6013.0-14.0	.04	.03	NA	6.1	2.67 ✓	Sd,sl/dol,sh lam
65	6014.0-15.0	.04	.01	NA	4.8	2.71	Sd,sl/dol,sh lam
66	6015.0-16.0	.68+	.27+	.39	2.6	2.69	Sd,sl/dol,sh lam
67	6016.0-17.0	88.+	48.+	.14	6.1	2.65 ✓	Sd,sh lam
68	6017.0-18.0	.02	.02	.03	3.2	2.71	Sd,sl/dol,sh lam
69	6018.0-19.0	2.9	.37	2.4	6.5	2.66 ✓	Sd
70	6019.0-20.0	.27	.05	.16	3.0	2.70 VF	Sd
71	6020.0-21.0	.03	.02	.02	1.3	2.72	Sd
72	6021.0-22.0	1.6	1.4	.07	3.8	2.68 ✓	Sd
73	6022.0-23.0	496.	1.6	226.	6.1	2.68 ✓VF	Sd
74@	6023.0-24.0	7.2	NA	.09	10.0	2.63 ✓	Sd
75	6024.0-25.0	11.	3.0	.69	9.0	2.66 ✓VF	Sd
76	6025.0-26.0	7.6	1.7	1.9	9.4	2.65 ✓	Sd
	6026.0-27.0						Core Not Received

+ - Dehydration crack affecting permeability
VF - Vertical fracture present
@ - Plug Dean-Stark analysis - Not suitable for full diameter sampling

TerraTek Core Services, Inc.®

University Research Park - 360 Wakara Way - Salt Lake City, Utah 84108 - (801) 584-2480 - TWX 910-925-5284

ENVIROCORP SERVICES & TECHNOLOGY, INC. Date: 7-DEC-1989 TTCS File #: 5398
Well: Aristech Chemical WDW #3

FULL DIAMETER PERMEABILITY AND POROSITY

Sample Number	Depth (feet)	Permeability Horz (md)	Horz-90 (md)	Vert (md)	Porosity %	Grain Density (gm/cc)	Lithology
77	6027.0-28.0	6.8	6.6	7.6	10.3	2.63 ✓	Sd
78	6028.0-29.0	30.	2.1	13.	6.6	2.67 ✓ VF	Sd
79	6029.0-30.0	11.	5.2	13.	8.5	2.65 ✓ VF	Sd
80@	6030.0-31.0	5.7	NA	18.+	12.1	2.64 ✓	Sd
81	6031.0-32.0	4.4	2.6	NA	11.0	2.65 ✓	Sd
82	6032.0-33.0	5.2	5.2	NA	9.0	2.65 ✓	Sd
83	6033.0-34.0	5.7	5.5	NA	9.6	2.63 ✓	Sd
84	6034.0-35.0	5.6	3.8	NA	12.6	2.60 ✓	Sd
85	6035.0-36.0	2.7	2.0	NA	13.3	2.60 ✓	Sd
86	6036.0-37.0	2.1	1.3	3.9	14.6	2.59 ✓	Sd
87	6037.0-38.0	2.8	2.1	2.2	13.0	2.61 ✓	Sd
88@	6038.0-39.0	3.7	NA	3.7	14.7	2.58 ✓	Sd
89@	6039.0-40.0	3.1	NA	8.7	15.5	2.58 ✓	Sd
90@	6040.0-41.0	1.2	NA	5.7	13.3	2.59 ✓	Sd
91	6041.0-42.0	3.8	2.0	4.2	13.9	2.57 ✓ VF	Sd
92	6042.0-43.0	3.9	1.3	3.4	15.3	2.63 ✓ VF	Sd,few sh lam
93	6043.0-44.0	6.3	1.6	8.9	14.5	2.60 ✓ VF	Sd,few sh lam
94	6044.0-45.0	.60	.27	.39	10.8	2.65 ✓ VF	Sd,sl/lmy
95	6045.0-46.0	.04	.02	.05	6.0	2.66 ✓ VF	Sd,sl/shy
96	6046.0-47.0	279.	.10	489.	8.8	2.65 ✓ VF	Sd,sl/shy,sh lam

+ - Dehydration crack affecting permeability
VF - Vertical fracture present
@ - Plug Dean-Stark analysis - Not suitable for full diameter sampling

TerraTek Core Services, Inc.®

University Research Park · 360 Wakara Way · Salt Lake City, Utah 84108 · (801) 584-2480 · TWX 910-925-5284

ENVIROCORP SERVICES & TECHNOLOGY, INC. Date: 7-DEC-1989 TTCS File #: 5398
Well: Aristech Chemical WDW #3

FULL DIAMETER PERMEABILITY AND POROSITY

Sample Number	Depth (feet)	Permeability Horz (md)	Permeability Horz-90 (md)	Permeability Vert (md)	Porosity %	Grain Density (gm/cc)	Lithology
97	6047.0-48.0	15.	.02	15.	5.2	2.71 VF	Sd,sl/dol,sl/shy
98	6048.0-49.0	.03	.01	.02	1.6	2.70	Sd,sl/dol,sh lam
99	6049.0-50.0	<.01	<.01	<.01	1.0	2.74	Sd,dol,sh lam
100	6050.0-51.0	.02	.02	<.01	2.2	2.74	Sd,dol,sh lam
101	6051.0-52.0	<.01	<.01	<.01	2.4	2.69	Sd,sl/dol,sh lam
102	6052.0-53.0	<.01	<.01	<.01	1.7	2.68 ✓	Sd,sl/dol,sh lam
103	6053.0-54.0	.02	.01	<.01	2.7	2.72	Sd,dol,sh lam
104	6054.0-55.0	.06	.05	<.01	5.5	2.70	Sd,dol,sh lam
105	6055.0-56.0	.24+	.09	.02	6.6	2.69	Sd,dol,few sh lam
106	6056.0-57.0	.28+	.13	.03	7.4	2.69	Sd,dol,few sh lam
107	6057.0-58.0	.09	.09	NA	8.2	2.70	Sd,dol
108	6058.0-59.0	.25	.25	NA	7.2	2.65 ✓	Sd
109	6059.0-60.0	.16	.08	.01	5.3	2.69	Sd,sl/dol
110	6060.0-61.0	.01	.01	<.01	4.8	2.69	Sd,sl/dol,few sh lam
111	6061.0-62.0	1.3	.21	.36	7.8	2.71 VF	Sd,sl/dol
112	6062.0-63.0	.03	.03	.03	5.8	2.70	Sd,sl/dol,few sh lam
113	6063.0-64.0	.87+	.05	.85	6.1	2.70	Sd,dol,sh lam
114	6064.0-65.0	.09	.08	.02	6.2	2.66 ✓	Sd,sl/dol,sh lam
115	6065.0-66.0	.08	.02	.04	4.7	2.68 ✓	Sd,sl/dol,few sh lam
116	6066.0-67.0	.01	.01	.01	4.8	2.69	Sd,sl/dol,sh lam
117	6067.0-68.0	15.	.02	3.8	5.2	2.69 VF	Sd,sl/dol,sh lam

+ - Dehydration crack affecting permeability
VF - Vertical fracture present

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ENVIROCORP SERVICES & TECHNOLOGY, INC. Date: 7-DEC-1989 TTCS File #: 5398
Well: Aristech Chemical WDW #3

FULL DIAMETER PERMEABILITY AND POROSITY

Sample Number	Depth (feet)	Permeability Horz (md)	Horz-90 (md)	Vert (md)	Porosity %	Grain Density (gm/cc)	Lithology
118	6068.0-69.0	.02	.01	.01	3.6	2.70	Sd,sl/dol,sh lam
119	6069.0-70.0	.04	.03	.02	4.4	2.61 ✓	Sd,sl/lmy,sh lam
120	6070.0-71.0	.02	.01	<.01	3.4	2.63 ✓	Sd,sh lam
121	6071.0-72.0	.05	.05	.01	2.4	2.67 ✓	Sd,sl/lmy,sh lam
122	6072.0-73.0	.07+	.02	<.01	0.9	2.70	Sd,sl/dol,sh stks
123	6073.0-74.0	.03	<.01	.02	0.7	2.76	Sd,dol,sh stks
124	6074.0-75.0	.06	.02	.06	0.9	2.82	Dol,sdy,sh stks
125	6075.0-76.0	<.01	<.01	NA	2.8	2.75	Sd,dol
126	6076.0-77.0	1.3+	.18+	.02	4.5	2.76	Sd,dol,sl/shy
127	6077.0-78.0	.63+	.04	NA	2.9	2.71	Sd,dol,sl/shy
128@	6078.0-79.0	<.01	NA	.92+	2.0	2.73	Sd,dol,sl/shy
Granite Basement							
129	6079.0-80.0	20.	.05	6.7	3.4	2.63 VF	Ign
130@	6080.0-81.0	.13+	NA	.01	1.9	2.71	Ign,pyr
131	6081.0-82.0	.03	.02	.02	2.2	2.62	Ign
132	6082.0-83.0	.01	.01	.03	1.8	2.61	Ign
133	6083.0-84.0	.02	.02	.03	1.1	2.65	Ign
134	6084.0-85.0	.07	.05	.09	1.5	2.64	Ign
135	6085.0-86.0	.44+	.02	.03	2.5	2.66	Ign
136	6086.0-87.0	2.2+	.07	.41	2.4	2.66	Ign
137	6087.0-88.0	.06	.02	.03	1.5	2.65	Ign

40' ≤ 2.65

+ - Dehydration crack affecting permeability
VF - Vertical fracture present
@ - Plug Dean-Stark analysis - Not suitable for full diameter sampling

ENVIROCORP SERVICES & TECHNOLOGY, INC. Date: 7-DEC-1989 TTCS File #: 5398
Well: Aristech Chemical WDW #3

FULL DIAMETER PERMEABILITY AND POROSITY

Sample Number	Depth (feet)	Permeability Horz (md)	Permeability Horz-90 (md)	Permeability Vert (md)	Porosity %	Grain Density (gm/cc)	Lithology
138	6088.0-89.0	.02	.02	.03	2.3	2.67	Ign
139	6089.0-90.0	.02	.01	.02	2.3	2.66	Ign
140	6090.0-91.0	.13+	.11+	.02	1.5	2.69	Ign
141	6091.0-92.0	.27+	.16+	.04	2.5	2.68	Ign
142	6092.0-93.0	.01	.01	.02	1.0	2.65	Ign
143	6093.0-94.0	.03	.03	.04	0.9	2.66	Ign
144	6094.0-95.0	.02	<.01	.02	1.3	2.69	Ign
145	6095.0-96.0	6.3+	3.6+	.02	0.5	2.71	Ign
146	6096.0-97.0	.01	.01	.02	0.8	2.76	Ign
147	6097.0-98.0	.01	<.01	.02	0.3	2.73	Ign
148	6098.0-99.0	.01	.01	.02	0.3	2.76	Ign
149	6099.0-00.0	<.01	<.01	.01	0.3	2.77	Ign
150	6100.0-01.0	.01	.01	.06	0.2	2.74	Ign
151	6101.0-02.0	<.01	<.01	.05	0.8	2.82	Ign
152	6102.0-03.0	.01	.01	.03	0.7	2.84	Ign
153	6103.0-04.0	.03	.02	.06	0.6	2.74	Ign
154	6104.0-05.0	.01	.01	.01	0.3	2.76	Ign
155	6105.0-06.0	<.01	<.01	.01	0.4	2.77	Ign
156	6106.0-07.0	.01	.01	.01	0.3	2.72	Ign
157	6107.0-08.0	.51+	.40+	.04	1.3	2.72	Ign
158	6108.0-09.0	1.5+	1.1+	.06	1.1	2.69	Ign

+ - Dehydration crack affecting permeability

P2-90 002633 Box 31

APPENDIX 5.3-C

CHEMICAL ANALYSIS, BEREA SAMPLE IN SCIOTO COUNTY BRINE WELL

No.20

Brine Sample No. 20
D. S Lab No 182

GEOLOGICAL SURVEY OF OHIO

WILBER STOUT, State Geologist
COLUMBUS

BULLETIN 37

TESTS ON SAMPLES

Material sampled Brine
Name of bed Berea sand

Sampled by W. M. Knight, Portsmouth
Date of sampling March, 1931
Tests made by Downs Schaaf, analyst

County Scioto
Township Jefferson
Section 9 (Houston Hollow)
Property owner Chas. Ziegler lease #2
Operator Local company, Edward Kleffner, president, W. M. Knight, secretary, 502 Union S
Portsmouth

1,0770 @ 20°C

Specific gravity, 1.078 at 15°C. Mineral sediment, none.

	Composition of saline matter	
Cl	62.78	— 68,98 Gr/Liter
Br	0.47	— .5170 Gr/Lite
SO_4	0.05	
CO_3	none	
HCO_3	0.02	
Na	22.86	— 25.13 Gr/Liter
K	0.20	— ,220
Ca	10.80	
Mg	2.65	
$(Al.Fe)_2O_3$	0.15	
SiO_2	0.02	
Sr	----	
	100.00	

Total dissolved solids 110.0 grams per liter
109.86 gm/l @ 1.0770
102.0 " " kilogram

Driller's record

Elevation of well head, 655 ft.

	Top	Bottom
Berea sand	256	315
Total depth		339

Pumps about one-inch stream of brine regularly. Water 8 feet in sand or at 264 feet.

Brine Sample No. 46
DS Lab. No. 263

No. 4

GEOLOGICAL SURVEY OF OHIO

WILBER STOUT, State Geologist
COLUMBUS

BULLETIN 37

TESTS ON SAMPLES

Material sampled Brine
Name of bed Second Water of Big Lime
County Lawrence
Township Elizabeth
Section 25
Sampled by W. R. Maxey
Date of sampling Oct., 1931
Tests made by Downs Schaaf
Property owner Ceramic Clay Co. No. 1
Operator Ohio Fuel Gas Co.

1,159 @ 20°C

Specific gravity, 1.16 at 15°C. Mineral sediment, none

Composition of saline matter

Cl	152,218	62.69	— 152,20 Gr/Liter
Br	1,967	0.81	1.9670 Gr/Liter
SO_4	291	0.12	.29
CO_3	—	none	
HCO_3	486	0.02	
Na	45,211	18.62	-4520 gr/Liter
K	1,627	0.67	— 1.628 Gr/Liter
Ca	31,857	13.12	
Mg	8,110	3.34	
$(Al.Fe)_2O_3$	85	0.035	
SiO_2	12	0.005	
Sr	1,334	0.57	
		100.000	

Total dissolved solids
243.02 grams per liter
242.81 g/l
209.5 grams per kilogram

Drillers record

Brine from a depth of about 2,800 ft.

no shales, etc.?

	Top	Bottom	
Sand	520	540	No water
Sand	585	597	25,500 cu.ft.at 592
Salt sand	665	710	½ bbl. water 675-680
Sand	720	760	3 " " 740
Maxton sand	760	770	
Big Injun sand	865	1078	
Hamden sand	1340	1350	
Berea grit sand	1480	1528	Hole full water. No oil or gas
Niagara lime	2340	2948	Brine sample about 2800
Clinton sand	3199	3207	94,560 cu.ft. No oil or water
Total depth		3252	

Sample #121

82751

GEOLOGICAL SURVEY OF OHIO

JOHN H. MELVIN, State Geologist
COLUMBUS

TESTS ON SAMPLES

Material sampled Brine
Name of bed Trempealeau
Depth 3840' Bailer sample
Sampled by
Date of sampling Nov. 1964
Tests made by Dow Chemical
W7-512

Quad. Sciotoville
County Scioto
Township Harrison
Section SE 17
Property owner Albert E. Will #1
Operator Young & Henneberger
Well permit #202

Brine Bottle No. 93

	1.1785 @ 20/20°C
Sp. Gr. at 25/25°C	1.1771
°Be'	21.8
% $CaCl_2$	6.04
% $MgCl_2$	2.17
Ratio % $CaCl_2$/% $MgCl_2$	2.78
% NaCl	12.76
% KCl	0.53
	21.50
	215.0 gm/kilogm
	253.38 gm/l.

FORM FB 7-62

PAN AMERICAN PETROLEUM CORPORATION
RESEARCH DEPARTMENT
WATER ANALYSIS

Note - This is OGS Brine sample #121

W-398-D

ase Albert R. Will Well No. 1 Lab. No. T-16758
County Scioto State Ohio
ld Blk. Section 17 T. R.
arter or Survey Twp. Harrison 1/4 SE Sample Series No.
Exact Location
Producing Stratum PBTD Total Depth
Stratum Yielding Sample Trampealeau From To
Condition of Well Method Used Bailer Cable Tool
Sample Collected From Date Collected Date Received
Collected by Date File
Transmittal Letter by
(Central Division)

Radicle	Per Cent by Analysis	(a) P. P. M.	(b)	(a) X (b)	Per Cent Reacting Value	Calculated Compound	P. P. M.
Na	23.19	55,397	.0435	2,409.85	28.27	Na_2SO_4	
Ca	10.50	25,100	.0499	1,252.49	14.69	NaCl	140,828
Mg	3.05	7,300	.0822	600.06	7.04	Na_2CO_3	
Fe						$NaHCO_3$	47
						$CaSO_4$	248
						$CaCl_2$	69,311
SO_4	.07	175	.0208	3.64	.04	$CaCO_3$	
Cl	63.18	151,000	.0282	4,258.20	49.95	$Ca(HCO_3)_2$	
CO_3	0	0	.0333	0	0	$MgSO_4$	
HCO_3	.01	34	.0164	.56	.01	$MgCl_2$	28,572
H_2S						$MgCO_3$	
						$Mg(HCO_3)_2$	

Total solids as a summation of radicles 239,006 P.P.M.
Total solids by evaporation and ignition of residue at low red heat 259,760 P.P.M.
Sample as received: Resistivity: ohms/M²M .046 at 77°F. pH Value 5.4 Specific Gravity 60°/60°F. 1.178

PROPERTIES OF REACTION IN PER CENT

PRIMARY SALINITY: SO_4 + Cl = ... with equal value Na (K) .... = 56.54 %
SECONDARY SALINITY: If SO_4 + Cl is greater than Na (K) .... = 43.44 %
Then SO_4 + Cl = ... with equal value of Ca + Mg .... = %
PRIMARY ALKALINITY: Excess Na (K) over SO_4 + Cl = ... with equal value of CO_3 + S .... = %
SECONDARY ALKALINITY: Excess Ca + Mg over SO_4 + Cl = ... with equal value of CO_3 + ... = .02 %
CHLORIDE SALINITY: Cl ÷ (SO_4 + Cl) = ... X 100% .... = 99.92
SULPHATE SALINITY: SO_4 ÷ (SO_4 + Cl = ... X 100% .... = .08

NOTE: Multiply Parts per Million by .0583 to obtain Grains per Gallon.

REMARKS:

K. W. Bolt
R. S. Tremaine
G. W. Schmidt (4)

mg/l (ppm)

Iodide	0
Bromide	520

Analyst James J. Elliott Date 12-15-64

STATE OF OHIO
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF GEOLOGICAL SURVEY

File No. 308

County Scioto

Township Bloom

Section 35

15' Quad. Oak Hill

7½' Quad.

TESTS ON SAMPLES

Material sampled Brine

Tests made by Dow Chemical

Name of bed depths of 1000', 1500' and 1900'

Laboratory number SSR 184-613

Sampled by

Property owner Dow Ironton #3 T.D. 2030

Date of sampling 1-4-53

Operator

Samples taken at completion of bailing

First Day 1910-1940 Second Day 1950-1972

Sample No.	2	2	1
Depth from top of well	1900	1500	1000
Sp. Gr. at 20°C	1.1967	1.1967	1.1967
°Be'	23.83	23.83	23.83
% $CaCl_2$	9.30		
% $MgCl_2$	3.09		
$\frac{\%CaCl_2}{\% MgCl_2}$	3.0		
%KCl	0.26		
% NaCl	10.3		
% Br	.1521		
% I_2	.0012		

STATE OF OHIO
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF GEOLOGICAL SURVEY

File No. 305

County Scioto

Township Green

Section Lot 29

15' Quad. Greenup

7½' Quad.

TESTS ON SAMPLES

Material sampled Brine

Name of bed

Sampled by

Date of sampling 3/12/53

Tests made by Dow Chemical

Laboratory number SSR 186-831

Property owner Dow Ironton Well 5 T.D. 1631

Operator

Located 4 miles south of Wheelersburg on U. S. 52

Sample depth from surface	200	1500
Sp. Gr. at 20°C	1.1817	1.1817
°Be'	22.30	22.30
% $CaCl_2$	8.67	8.64
% $MgCl_2$	2.98	3.00
Ratio $\frac{\%CaCl_2}{\%MgCl_2}$	2.9	2.9
% NaCl	9.4	9.4
% KCl	0.22	0.24
% Br_2.	0.1372	0.1371
% I_2	0.0010	0.0010

Samples taken at completion of bailing.

STATE OF OHIO
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF GEOLOGICAL SURVEY

File No. 306
County Lawrence
Township Hamilton
Section 5
15' Quad. Greenup
7½' Quad.

TESTS ON SAMPLES

Material sampled Brine
Name of bed Depth
Sampled by
Date of sampling 12-4-62

Tests made by Dow Chemical
Laboratory number SSR 183-620
Property owner Dow Irontonn #2
Operator

#2 Ironton - Section 7, Hamilton Twp., Lawrence County, Ohio, Total depth 2031 ft. The Sp. Gr. on this sample appears low indicating some dilution.

Spec. Gr. at 20/20C°	1.1897
°Be'.	23.12
% $CaCl_2$	8.99
% $MgCl_2$	2.88
% NaCl	9.90
% KCl	0.21
Ratio $\frac{\%CaCl_2}{\% MgCl_2}$	3.12
% Br	0.1496
% I	0.0011

STATE OF OHIO
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF GEOLOGICAL SURVEY

File No. 307

County Lawrence

Township Elizabeth

Section 4

15' Quad. Ironton

7½' Quad.

TESTS ON SAMPLES

Material sampled Brine

Name of bed depth 250' and 2250'

Sampled by

Date of sampling 3-16-53

Tests made by Dow Chemical

Laboratory number SS" 186-217

Property owner Dow Ironton well 4 T.D.23

Operator

Sample taken from bailer at depth indicated after acidifying and completion of bailing.

Sample depth from surface (ft.)	250	2250
Sp. Gra. at 20°C	1.2045	1.2062
°Be'	24.62	24.79
% $CaCl_2$	9.84	9.82
% $MgCl_2$	3.52	3.39
Ratio $\frac{\%CaCl_2}{\%MgCl_2}$	2.80	2.90
% NaCl	9.9	10.5
% KCl	0.24	0.24
% Br	0.1485	0.1525
% I_2.	0.0013	0.0013

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APPENDIX 9.1-A

INTERFERENCE TEST ANALYSIS

8.3.4 Pressure Transient Well Tests and Final Injection Interval Parameter Assignments

Three types of well tests were conducted and analyzed during the calibration process conducted in order to model the Aristech Chemical Corporation, Haverhill, Ohio site: pressure fall-off, step-rate, and inter-well pressure interference tests. Analysis of these tests, along with the discussion of other related injection interval parameter assignments are included in the following section.

Fall-Off Test Analysis

Preliminary reservoir characterization for the Aristech Chemical Corporation, Haverhill, Ohio facility was accomplished through the analysis of injection pressure fall-off tests. Figures 8.3.4-1 and 8.3.4-2 exhibit plots of these pressure fall-off tests as pressure versus the logarithm of elapsed shut-in time.

The first step in analysis of the pressure fall-off portion of pressure transient data is based upon treating each well as injecting for a long time at a constant rate, q, prior to shut-in. Basic transient pressure theory (Collins, 1961) then indicates that the bottomhole pressure should decrease in accord with

$$(1) \qquad P_{BH} = P_{FL} - 2420.6 \frac{q\mu}{Kh} \left[-Ei \left(- \frac{\phi \mu c R^2}{1.056 \times 10^{-3} K \Delta t} \right) + 2S \right]$$

where

S = skin factor (dimensionless)

R = "effective" well radius (feet)

P_{FL} = bottomhole pressure flowing just prior to shut-in (psi)

ϕ = porosity (fraction)

q = flow rate (gpm)

μ = viscosity of reservoir fluid (cp.)

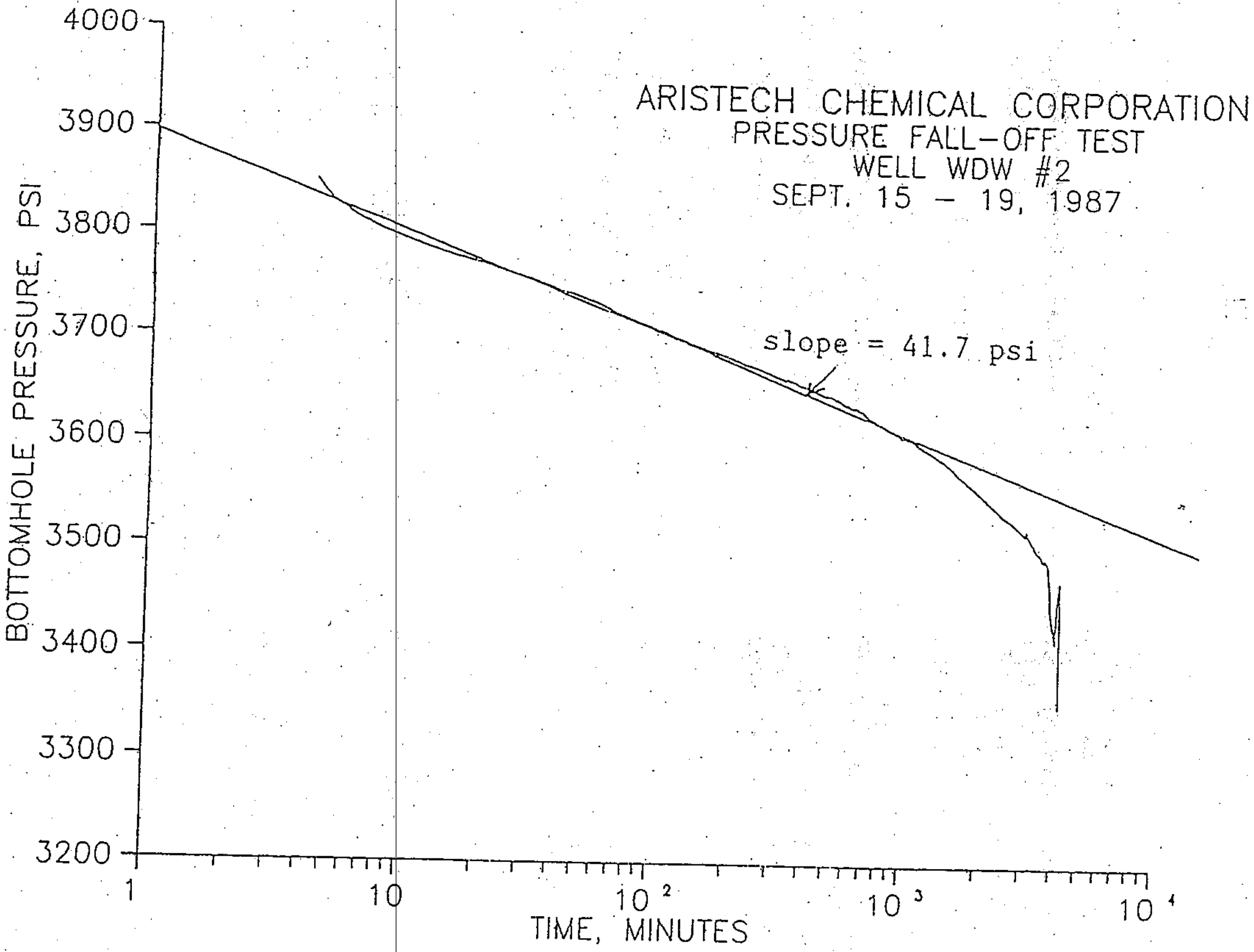
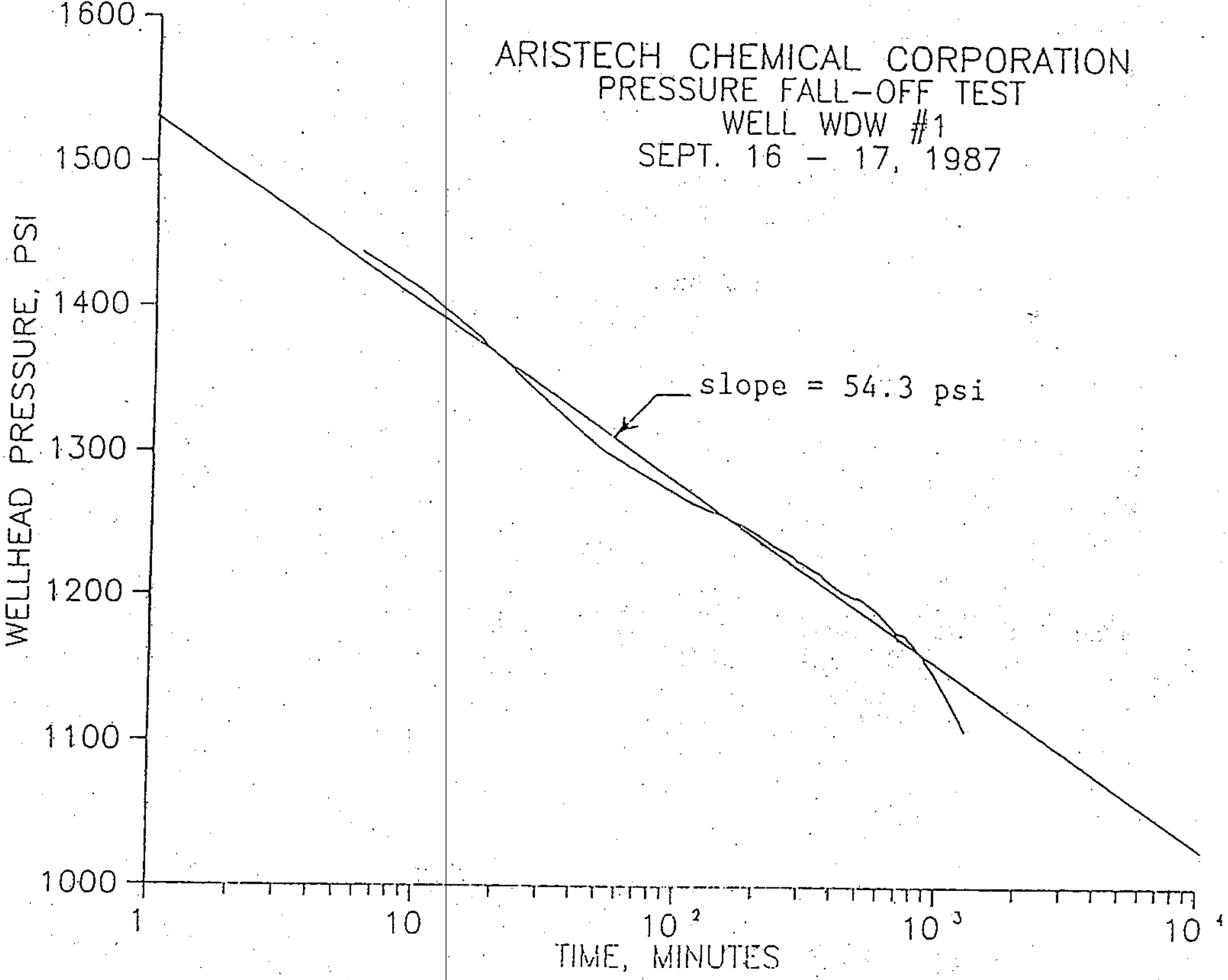

ARISTECH CHEMICAL CORPORATION
PRESSURE FALL-OFF TEST
WELL WDW #2
SEPT. 15 - 19, 1987
slope = 41.7 psi
BOTTOMHOLE PRESSURE, PSI
4000
3900
3800
3700
3600
3500
3400
3300
3200
1
10
10^2
10^3
10^4
TIME, MINUTES

FIGURE 8.3.4-1



ARISTECH CHEMICAL CORPORATION
PRESSURE FALL-OFF TEST
WELL WDW #1
SEPT. 16 - 17, 1987

FIGURE 8.3.4-2

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Box 34

characteristics of the Mt. Simon disposal interval and account for the over-calculation of pressure during the early time of the November interference test.

9.2 Step-Rate Test Analysis

Figure 9.2-1 exhibits the results of the November 30, 1989 step-rate test executed at Aristech Chemical Corporation WDW No. 3. This test was carried out using rates of 21.2 gpm, 27.6 gpm, 31.2 gpm and 33.6 gpm. Figure 9.2-1 indicates that a pressure-sensitive increase in permeability begins when the bottomhole injection pressure reaches a threshold value. Since an injection rate starting at 21.2 gpm caused the pressure to exceed the threshold value prior to stabilization during the first flow period, a specific value for this threshold can not be calculated. However, a qualitative review of the data shows that this critical pressure is less than 3400 psi, and more nearly 3200 psi at a depth of 5416 feet below ground level (BGL). This corresponds to a gradient of between 0.59 psi/ft. and 0.63 psi/ft. When pressure is above a gradient of this magnitude, increases in permeability will occur in the Mt. Simon.

The probable mechanism for this observed pressure-sensitive permeability is the opening of an extensive network of pre-existing micro-fractures in the Mt. Simon. Both lithology descriptions and core data discussed in the geology section and appendices of this document support this view.

The anticipated factor limiting the vertical extension of this fracture opening process is that closing stresses in less competent rocks will be greater than those in the Mt. Simon. These issues are addressed in greater detail in Appendix 9.2-A.

A second step-rate test was performed on WDW No. 3 in March of 1991. Results and analysis of this test will be forwarded to Ohio EPA when they become available.

9.3 In-Situ Stress Tests

Numerous in-situ stress tests are scheduled to be run in the test/monitor well which is currently being constructed at Aristech. These test results will have a direct bearing on the calculation of maximum permitted injection pressures at the Aristech facility. Results of the stress testing will be submitted to Ohio EPA as an addendum to this repermit application.

P1-91

Report is about 200 pages long

Vol. IV

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APPENDIX 9.0-A

RAW DATA - PRESSURE FALL-OFF, STEP RATE AND INTERFERENCE TESTS FOR WELLS NO. 1, NO. 2 AND NO. 3

ENVIROCORP SERVICES & TECHNOLOGY, INC.

P1-91

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APPENDIX 7.3-B

CHEMICAL ANALYSIS OF LOGAN AND BEREA FORMATIONS

SAMPLES FROM TEST/MONITOR WELL

Test Well Analytical Report

Berea

		Potable Water	Berea Formation Fluid		
			Sample 1	Duplicate	Avg.
InOrganics					
Alkalinity	ppm	N.A.	8	N.A.	8
Ammonia-Nitrogen	ppm	N.A.	150	N.A.	150
Bromide	ppm	N.A.	564	558	561
Bicarbonate	ppm	N.A.	10	N.A.	10
Carbonates	ppm	N.A.	0	N.A.	0
Chloride	ppm	N.A.	82500	82500	82500
Dissolved Oxygen	ppm				
Nitrates	ppm	N.A.	<0.03	N.A.	<0.03
Tot.Dissol.Solids	ppm	N.A.	135000	133000	134000
Tot.Suspnd Solids	ppm	N.A.	2680	N.A.	2680
Specific Conductance	umohms/cm	N.A.	192000	N.A.	192000
Specific Gravity	units	N.A.	1.095	1.095	1.095
Silicates	ppm	N.A.	5.2 N	N.A.	5.2 N
Sulfates	ppm	N.A.	<5	<5	<5
Viscosity					
Metals					
Aluminum	ppm	N.A.	0.186b	N.A.	0.186b
Barium	ppm	N.A.	141 E	N.A.	141 E
Calcium	ppm	N.A.	9790	N.A.	9790
Hex.Chromium	ppm				
Tot.Chromium	ppm	N.A.	0.0248 N	N.A.	0.025 N
Iron	ppm	N.A.	188 E	N.A.	188 E
Lead	ppm	N.A.	0.719 S	N.A.	0.719 S
Magnesium	ppm	N.A.	2960	N.A.	2960
Manganese	ppm	N.A.	2.540 EN	N.A.	2.540 EN
Potassium	ppm	N.A.	260	N.A.	260
Sodium	ppm	N.A.	32900	N.A.	32900
Volatiles					
Acetone	ppm	0.005 BJ	0.410 BJ	N.A.	N.D. BL
Toluene	ppm	0.002 J	0.640	N.A.	0.640 L
Formic Acid	ppm	N.A.	<10	<10	<10
Other Volatiles					
Methylene Chloride	ppm	0.005 B	0.420 B	N.A.	N.D. BL
Benzene	ppm	N.D.	0.200 J	N.A.	0.200 J
Methyl Ethyl Ketone	ppm	0.120	N.D.	N.A.	N.D. L
Chloroform	ppm	0.023	N.D.	N.A.	N.D.
Bromoform	ppm	0.001 J	N.D.	N.A.	N.D.
Bromodichloromethane	ppm	0.012	N.D.	N.A.	N.D.
Dibromochloromethane	ppm	0.006	N.D.	N.A.	N.D.
Ethylbenzene	ppm	0.039	0.200 J	N.A.	0.200 J
Xylenes (total)	ppm	0.190	2.000	N.A.	2.0
4-Methyl-2-Pentanone	ppm	0.017	N.D.	N.A.	N.D.

Test Well Analytical Report
Berea

		Potable Water	Berea Formation Fluid Sample 1	Duplicate	Avg.
Semi-Volatiles					
Acetophenone	ppm	N.D.	N.D.	N.D.	N.D.
Alpha-Picoline	ppm	N.D.	N.D.	N.D.	N.D.
Aniline	ppm	N.D.	N.D.	N.D.	N.D.
Phenol	ppm	N.D.	N.D.	N.D.	N.D.
Cumene (screen)	ppm	N.D.	N.D.	N.D.	N.D.
DiMethylBenzylAlcohol	ppm	N.D.	N.D.	N.D.	N.D.
DiPhenylAmine	ppm	N.D.	N.D.	N.D.	N.D.
Other Semi-Volatiles		N.D.	N.D.	N.D.	N.D.
2-Methylnaphthalene	ppm	N.D.	N.D.	N.D.	N.D.
N-Nitrosodiphenylamine	ppm	N.D.	0.004 J1	0.003 J1	0.004 J1
bis(2Ethylhexyl)Phthalate	ppm	N.D.	0.009 J	0.005 J	0.007 JL
Total Phenolics					
Formation	ppm	N.A.	<0.050	N.A.	<0.050
Before Formation	ppm	N.A.	<0.050	N.A.	<0.050
After Formation	ppm	N.A.	0.090	0.070	0.080

Footnotes:

1 - N-Nitrosodiphenylamine can not be seperated from Diphenylamine

b - reported value obtained was less than the CRDL (Contract Required Detection/Reporting Limit) but greater than or equal to the IDL (Instrument Detection Limit).

u - value was less than the IDL or was not detected.

E - reported value was estimated because of interference.

N - spiked sample recovery was not within control limits.

B - analyte is found in the associated blank as well as the sample. Possible blank contamination: the data user should evaluate this data carefully.

J - estimated value. Mass spectral data indicates the presence of a compound below the PQL (Procedural Quantification Limit).

L - common laboratory cross-contaminant. Result is reported as 'non-detect' if result is less than 10 times the concentration found in any associated blank. Also, cross-contaminant may be introduced into sample upon dilution, even where it does not appear in any associated blank.

S - reported value was determined by method of standard additions.

ND (or N.D.) - Not Detected. If the sample concentration is less than 10 times the concentration of a material found in the blank, then the result is taken as 'non-detected'. Also, 'non-detected' is used when one sample of a pair has a reading, but duplicate or split samples does not show similar readings.

NA (or N.A.) - not analyzed.