TECHNICAL CONSULTING REPORTS PREPARED IN SUPPORT OF THE DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT FOR NATURAL GAS PRODUCTION IN NEW YORK STATE

Prepared for:

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ALPHA ENVIRONMENTAL CONSULTANTS, INC.

SUMMARY

NYSERDA has been supporting projects to develop natural gas production from the Marcellus Shale since the early 1980s. Recent investigations indicate the potential recoverable gas from the Marcellus Shale may approach 20 trillion cubic feet, which could fuel New York's gas demand for approximately 20 years. It is estimated that the revenue associated with development of this resource may exceed one billion dollars per year.

Through its access to various technical resources, NYSERDA is assisting the New York State Department of Environmental Conservation (NYSDEC) to address issues identified in the Final Scope for the draft Supplemental Generic Environmental Impact Statement (dSGEIS) on the Oil, Gas and Solution Mining Regulatory Program, which the NYSDEC is developing for guidance on permitting horizontal drilling and high-volume hydraulic fracturing projects to develop the Marcellus shale and other low permeability gas reservoirs.

This document combines the individual summary reports prepared by three Project Consultants to NYSERDA to research, review, and summarize various issues within their respective areas of expertise. This document is presented in three chapters, each representing a "stand alone" report that addresses various technical issues, prepared by the Consultant under its respective NYSERDA contract. Each chapter contains a unique Table of Contents that identifies the scope of work contained in each consultant's report.

The range of technical issues researched and discussed within the three reports includes: existing regulations in New York and other gas-producing states; shale-gas geology in New York State; surface and ground water resources, use, and treatment; use of hydrofracturing chemicals and potential alternatives; the New York City watershed; multi-well site operations; induced seismicity; and potential community impacts.

ACKNOWLEDGMENTS

The Project Consultants are grateful for the cooperative effort, respective input, analysis, and contributions of the Project Team; which includes NYSERDA, the NYSDEC Division of Mineral Resources, Division of Water and other NYSDEC program personnel, and the diverse individuals comprising the technical consulting teams. The Consultants also acknowledge the assistance and contributions by other agencies such as the New York State Department of Health, New York State Geological Survey, United States Geological Survey, and many others, as identified and referenced within the individual Chapters.

CHAPTER 1

ISSUES RELATED TO DEVELOPING THE MARCELLUS SHALE AND OTHER LOW-PERMEABILITY GAS RESERVOIRS

Survey of Regulations in Gas-Producing States, NYS Water Resources, Geology, New York City Watershed, Multi-Well Operations, and Seismicity

Prepared by:
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Clifton Park, NY
NYSERDA Contract No. 11169

CHAPTER 2

WATER-RELATED ISSUES ASSOCIATED WITH GAS PRODUCTION IN THE MARCELLUS SHALE

Additives, Flowback Quality and Quantity, NYS Regulations, On-site Treatment, Green Technologies, Alternate Water Sources, and Water Well Testing

Prepared by:
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Fort Washington, PA
NYSERDA Contract No. 10666

CHAPTER 3

IMPACTS ON COMMUNITY CHARACTER OF HORIZONTAL DRILLING AND HIGH VOLUME HYDRAULIC FRACTURING IN MARCELLUS SHALE AND OTHER LOW-PERMEABILITY GAS RESERVOIRS

Noise, Visual, Community Character, and Cumulative Impacts

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ISSUES RELATED TO DEVELOPING THE MARCELLUS SHALE AND OTHER LOW-PERMEABILITY GAS RESERVOIRS

Survey of Regulations in Gas-Producing States,
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1.0 INTRODUCTION

This report was prepared by Alpha Environmental Consultants, Inc. (Alpha Environmental), in support of developing the draft Supplemental Generic Environmental Impact Statement (dSGEIS) for the oil, gas and solution mining program in New York State (NYS). The work was performed for the New York State Energy Research and Development Authority (NYSERDA) under NYSERDA contract #11169. The work by Alpha Environmental was supported by Alpha Geological Services, Inc. (Alpha Geoscience) through a subcontract to Alpha Environmental. These two companies are referenced herein, collectively, as “Alpha”.

The dSGEIS is being prepared by the New York State Department of Environmental Conservation (NYSDEC), which is responsible for regulating the development and production of oil and gas resources in NYS. The topics to be addressed within the dSGEIS are identified in the “Final Scope for Draft Supplemental Generic Environmental Impact Statement (dSGEIS) on the Oil, Gas and Solution Mining Regulatory Program” that was completed by the NYSDEC on February 6, 2009.

This report by Alpha summarizes specific topics identified within the Final Scope for the dGEIS. The topics address aspects of unconventional gas drilling that are different from vertically drilled gas wells. Those differences, which are unique to unconventional wells, include, but are not necessarily limited to: larger pads to accommodate multiple wells per pad; larger equipment to facilitate drilling and development of the longer horizontal wells bores; larger quantities of cuttings; larger quantities of water and chemicals in the frac fluids and flowback water; longer duration well site operations; more extensive fracing within the gas bearing zones; and development of gas resources in populated urban areas.

1.1 Scope and Objectives

Alpha completed five tasks that were identified in the Final Scope of SGEIS and outlined in Exhibit A of NYSERDA contract #11169. These tasks are briefly described herein.

1.1.1 Task 1: Regulatory Survey

The objective of the regulatory survey was to identify and review existing policies, procedures, regulations and recent regulatory changes pertaining to unconventional shale gas development. The objectives also included an evaluation of the strengths, weaknesses and problems encountered from the application of the regulations. This effort was focused on Pennsylvania, Colorado, New Mexico, Wyoming, Texas (and Fort Worth), West Virginia, Louisiana, Ohio and Arkansas where shale gas development is ongoing. The regulatory survey was focused on the specific requirements for the following items:

- **Pit rules and specifications**: Evaluate the need for specifications for pit liner construction, freeboard and separation distances.

- **Reclamation and waste disposal:** Evaluate the need for cuttings and pit liner disposal requirements.

- **Water well testing**: Identify whether baseline and post-drilling testing is or should be performed in NYS, and determine whether other states require testing. Identify testing parameters, sample type and frequency.

- **Fracturing fluid reporting**: Evaluate whether other states require reporting of frac composition, flowback composition, frac injection volumes, and flowback volumes.

- **Hydraulic fracturing operations**: Evaluate whether other states require separate notifications, reviews, permits, or approvals for each hydraulic fracturing operation.

- **Fluid use and recycling**: Evaluate whether other states regulate surface water withdrawals for hydraulic fracturing and what criteria are used. Evaluate whether other states restrict use of treated municipal water and whether they require treatment, reuse and recycling of drilling or frac fluids.

- **Materials handling and transport** : Review and identify U.S. and NYS statutes and regulations pertaining to transportation and on site storage of frac additions and assess the potential applicability of New York's chemical and petroleum bulk storage program. Evaluate whether references to DOT pertain to state or federal requirements.

- **Minimization of potential noise and lighting impacts** : Evaluate how other states have addressed potential noise and lighting impacts. This focus is to be limited to states whose multiple wells are being drilled from a common well pad.

- **Setbacks**: Evaluate whether other states have established or revised well/pad setback requirements due to longer duration drilling and high volume hydraulic fracturing at multi-well sites. Determine setbacks established by other states for domestic water supplies, surface water bodies, and private dwellings. Determine whether the setbacks in other states are from the surface well site, the entire well pad, or the well pad plus the entire horizontal well bore.

- **Multi-well pad reclamation practices** : Evaluate the typical reclamation practice for multi-well pads. Evaluate the range in size of the cleared area(s) after partial reclamation through production, and the implications with respect to visual impacts, stormwater and erosion/sedimentation control, and potential increased future flooding damage. Evaluate whether other states have assessed industry practices for multi-well pads and whether those practices meet or exceed requirements. Evaluate whether other states developed new requirements, guidelines or permit conditions to address unique issues.

- **NORM:** Evaluate whether other states assessed the occurrence of naturally occurring radioactive materials (NORM) from longer duration drilling operations at multi-well sites and larger accumulation of shale cuttings from horizontal drilling.

- **Stormwater Runoff:** Review and summarize best management practices employed in other states to prevent stormwater pollution from sites with greater than 1 acre of total disturbance (including the access road).

- **Recommended Information to Accompany Drilling Applications:** Develop a summary of recommended information to be required with a drilling application to allow for proper assessment of environmental impacts and appropriate mitigation measures, and provide sample application forms used by other states to collect the information.

1.1.2 Task 2: Water

The objective of this task was to address issues related to the potential impacts of horizontal drilling and high-volume hydraulic fracturing on water resources in NYS. This task encompasses ground water and surface water in general and also specific types of prolific aquifers (primary and principal aquifers) and watersheds within NYS that have basin-specific rules and regulations. The following are the subtasks within Task 2:

- Review the relevant jurisdictional ground water and surface water classifications, flow standards and quality standards in NYS established by the United States Environmental Protection Agency (USEPA), NYS, Delaware River Basin Commission (DRBC), New York City Department of Environmental Protection (NYCDEP), Susquehanna River Basin Commission (SRBC), and the Upper Delaware Council,

- Assess the adequacy of existing controls and protocols in the protection of aquifers, watersheds and recharge areas from historical oil and gas drilling in those areas,

- Evaluate potential mitigation measures to prevent transfer of invasive species by water handling procedures,

- Evaluate the sufficiency of protocols (water withdrawal applications and approval procedures) by existing authorities (NYSDEC, SRBC, and DRBC) to address potential impacts to surface water bodies from water withdrawals,

- Evaluate the cumulative impacts of multiple water withdrawals, and

- Conduct an analysis of recent flooding in Broome, Delaware and Sullivan counties to assess whether existing flood controls are adequate.

1.1.3 Task 3: New York City Watershed

The objective of this task was to evaluate the adequacy of existing NYCDEP and NYSDEC regulations for protecting the NYC watershed from potential impacts from horizontal drilling and high-volume hydraulic fracturing. The following are the key elements to be addressed in Task 3:

- Review NYSDEP regulations for oil and gas drilling within the watershed and compare those with the relevant NYSDEC regulations, and

- Conduct a sensitivity analysis of the potential for contamination of the West of Hudson NYC watershed from a release of hydraulic fracturing fluids.

1.1.4 Task 4: Geology

The objective of Task 4 was to describe and map the distribution of the lithology and physical characteristics pertinent to the gas bearing potential of the Marcellus and Utica shales throughout NYS.

1.1.5 Task 5: Well Site Operations

The purpose of this task was to evaluate the potential environmental impacts of well site operations. The evaluation was focused on those potential impacts to soil, ground water, and surface water. The elements of Task 5 include:

- Identify environmental impacts unique to horizontal drilling that were not addressed in the existing GEIS,

- Evaluate whether there are any potential environmental impacts that could arise from utilizing well pads that are larger than those envisioned within the existing GEIS, and

- Evaluate whether additional controls need to be initiated to minimize potential impacts from the handling of the larger quantities and the longer duration of use of hydraulic fracturing fluids at each well pad.

1.2 Methods

The forgoing tasks were accomplished primarily through the identification and review of the regulations, best management practices, and guidance documents for the states and watershed regulatory agencies that are underlain by significant gas bearing shales. The document review was supplemented by telephone interviews of representatives from the various regulatory agencies when follow-up information was desirable. The review was also supplemented by onsite inspection of horizontal well drilling and hydraulic fracturing sites and by technical queries to the gas industry.

2.0 REGULATORY SURVEY RESULTS

The regulatory survey covered the previously identified states of Pennsylvania, Ohio, West Virginia, Colorado, Louisiana, Texas, Arkansas, Wyoming and New Mexico. The State of Texas also includes regulations for the City of Fort Worth, which adopted its own program to address conditions unique to an urban area.

Survey results for each state and the City of Fort Worth are provided on Tables 2.1 through 2.10. Each table identifies the lead regulatory agency or agencies and lists the pertinent regulations that describe the regulatory details for the various topics identified in Section 1.1.1. The appropriate reference sources for the details for each topic are also provided.

2.1 Pit Rules and Specifications

Pits are excavated at drilling sites for a variety of purposes. These include pits for drill cuttings and drilling mud, flowback water from hydraulic fracturing, and production waste. These pit types can be separated into permanent pits or impoundments, and temporary pits. Permanent pits and impoundments tend to be for long-term containment of production water or for storing fresh water or recycled water for multiple drilling and hydraulic fracturing sites. Operators may construct large centralized impoundments at locations separate from the drilling operations to store freshwater and frac flowback water for multiple well sites within a several mile radius of the impoundment. The frac flowback usually is contained in closed steel tanks in New York State; however, centralized, offsite impoundments and adequately lined, onsite, flowback pits are being considered for future use with horizontal well drilling and high volume fracturing operations and are included in the survey. Pits are not used for the storage or disposal of production waste in NYS; therefore, regulations limited to the storage or disposal of production waste in pits are not included in this review. Those rules and specifications that apply or appear relevant to the unconventional gas plays in each state are summarized below from the detailed information provided in Tables 2.1 through 2.10.

2.1.1 Arkansas

Arkansas requires a general permit from the Arkansas Division of Water for all pits regardless of use. This includes test pits, reserve pits, mud pits and production pits. Arkansas also has specific requirements for freshwater based drilling mud pits. The specifications include:

- Pits in 100-year floodplains must meet county or local requirements;
- Construction of pits in water bodies is prohibited;
- Pit construction in a wetland requires an U.S. Army Corp of Engineers permit;
- Site selection must maximize the distance from water bodies;
- The pit must be constructed above ground if the water table is 10 feet or less below the land surface, or the operator must use a closed loop system;

- Liners may be synthetic, clay (natural or bentonite), or material approved by the regulating agency;
- Synthetic liners must be at least 20-mil thick, have 4-inch overlapping welded seams, and cover the bottom and side walls;
- Use of a compacted clay or bentonite liner must create a impervious/impermeable barrier and be constructed in a manner consistent with sound engineering principles; and
- Pit walls and liner must be protected and maintained to prevent deterioration, overfill, puncture or leakage of fluids to waters of the state.

Arkansas has separate regulations when wells are drilled with oil-based muds or other constituents. These operations require synthetic pit liners. A closed-loop system is required within 100 feet of water bodies.

2.1.2 Colorado

- A permit is required for earthen pits being used for recycling fluids at multi-well sites.
- The aforementioned pits must be lined with a synthetic liner that is impervious, is resistant to degradation and failure, and has been installed in accordance with the manufacturer's specifications.
- Pit liners must be at least 24-mil thick, cover the entire bottom and sides, and be secured with a 12-inch deep anchor trench around the perimeter.
- The pit foundation must be 12 inches of compacted soil material with a maximum permeability of 1×10^{-7} cm/sec based on field and laboratory testing.
- The low permeability foundation requirement can be waived if a double liner system is utilized and the foundation material is free of objects capable of puncturing the liner.
- A leak detection system and monitoring is required in environmentally sensitive areas.

2.1.3 Fort Worth Texas

- Closed-loop mud systems (CLMS) with steel tanks are required for all gas drilling.

- Earthen pits can be used on lots $\geq$ 25 acres with separation distances of more than 1000 feet from a protected use such as a residence, religious institution, hospital building, school or public park.
- Freshwater pits must not be placed in any city-recognized drainage way, FEMA floodplain or floodway, existing city right-of-way, or city easement.
- Stand-alone freshwater fracture ponds (not located adjacent to a drilling site) must be located in agricultural or industrial zones. Fracture ponds cannot be located in residential, commercial, business, or special use areas. If not adjacent to the drilling site, fracture ponds can only be in areas contained in one of these specific zone types.
- Drilling pits may not be in a floodplain without a floodplain development permit.
- Freshwater fracturing pits must be enclosed by "open design" chain link, black or green fencing on all four sides.
- Drill pits will be fenced on all open sides during drilling operations (leaving the side occupied by the rig unfenced for access) and enclosed with a chain link fence on all sides after drilling operations have ceased.
- All drill pits must be approved by the City of Fort Worth.
- Fresh water pits may not be lined with a synthetic, impervious liner unless approved by the City Gas Inspector.
- No flowback water can be placed in an open pit.

2.1.4 New Mexico

The State of New Mexico's Oil Conservation Commission approved several revisions to the June 2008 Pit Rule on June 19, 2009 to address industry cost burdens. These revisions are mostly in regard to existing tanks that may not meet new construction specifications. New Mexico regulations require a permit for construction of all types of pits, which are subdivided into permanent and temporary pits. The discussion provided in this review focuses on the temporary pits that are commonly used for gas well development. The permit for any type of pit can be included as part of the overall well drilling and completion permit. The specifications are discussed as follows:

- Pits must be enclosed to prevent accidental or unauthorized access.
- A 6-foot high chain link fence, with at least two strands of barbed wire on top, is required if the pit is less than 1,000 feet from a permanent residence, school, institution, church or hospital. Any gates must be closed and locked if there is no responsible person on site.
- All other pits must have a 4-foot barbed wire fence with at least 4 strands of wire within the interval of 1.0 to 4.0 feet above grade to keep out livestock. Alterations will be accepted if equal or better.
- All temporary pits must have a geomembrane liner.
- The operator must anchor the liner with an 18-inch perimeter trench filled with compacted earth.
- No temporary pit can have a volume greater than 10 acre-feet.
- The pit liner must be 20 mil thick.
- The seams must run up and down the slopes, not across.
- The seams must have 4 to 6 inches of overlap and be welded by a qualified person.
- The liner must be a string reinforced, linear low-density polyethylene (LLDPE) or equivalent material.

2.1.5 Pennsylvania

Pennsylvania requires the preparation of a waste control and disposal plan prior to creating any pit at the well site. The pit specifications for freeboard, height above the water table, and sideslopes are similar in other states and are noted in the general specifications provided in Section 2.1.8. The following regulations are specific to well site pits in PA:

- The well site impoundment must not exceed 250,000 gallons in a single or connected network of pits.
- The total volume of all well site pits on one tract or related tracts of land must not exceed 500,000 gallons.
- The pit should be lined with 6 inches of a debris-free subgrade such as sand, clay or smooth gravel, if necessary.

- The liner should have a thickness of at least 30 mil. and be thick enough to prevent failure.
- The synthetic liner should satisfy EPA Method 9090 or other data approved by the regulatory agency.

Operators in Pennsylvania have constructed centralized impoundments, separate from the drill site, to store freshwater and flowback water for wells drilled within a several (2 to 4) mile radius of the impoundment. The size of the impoundments depends on site-specific conditions, operational needs, and regulatory criteria. The operator must complete a "worksheet for permitting of Marcellus shale pits and dams" to determine the regulatory program that applies to the proposed impoundment. Impoundments must meet the requirements of one or more of the following:

- PA Code Chapter 78.56 – 78.63 and the standards set forth in "Design, Construction and Maintenance Standards for Dam Embankments associated with Impoundments for Oil and Gas Wells",

- A dam permit from the Department's Dam Safety Program (Application Form 3140-PM-WE0001),

- And environmental assessment from the Department's Dam Safety Program (Application Form 3140–PM–WE0002, or

- A water obstruction and encroachment permit (Application Form 3930–PM-WE0036)

A site restoration plan is required to be submitted for all frac water impoundment pits or dams, which are required to be restored/reclaimed within nine months after completion of the last well that was serviced by the pit/impoundment.

2.1.6 West Virginia

- Pits must be designed in a manner to provide structural integrity for the life of the pit.
- The operator must develop a construction and reclamation plan prior to drilling.
- The operation is required to conduct regular inspections of all pits and ponds with a capacity greater than 5,000 barrels (210,000 gallons or 1040 cubic yards).
- The pit must be set back 75 feet from the wellhead.

2.1.7 Wyoming

- Approval of reserve pits that are adequate for reception and containment of cuttings is required prior to drilling.
- Special precautions are required where there is a need to prevent contamination of streams and potable water supplies and to protect human health and safety. These precautions include, but are not necessarily limited to, liners or membranes, monitoring systems and closed loop systems.

2.1.8 General Specifications

Several states identified general specifications that are not necessarily specific to unconventional gas development, but are different from specifications in the existing GEIS for oil and gas well site operations in NYS. These general provisions include:

- Maintenance of 2.0 feet of freeboard in each pit (Colorado requires monitoring of freeboard).
- Placement of pit bottoms a minimum of 20 inches above the seasonal high ground water level, except in New Mexico where 50 feet is required.
- Line pits with either synthetic liner (20 mil for New Mexico, 24 mil for Fort Worth, 30 mil for PA), with compacted natural clay, or with compacted cement/soil/bentonite mix. All liner types must have a maximum permeability of 1×10^{-7} cm/sec.

- Synthetic liners must be compatible with the chemistry of the contained fluid, placed in pits with sufficient slack to accommodate stretching, placed in a manner consistent with manufacturer's recommendations and sealed along seams in accordance with manufacturer's specifications.
- Pits should be constructed in a manner to prevent surface water from entering the pits.
- Pit sidewalls and bottoms should be free of objects capable of puncturing and ripping the synthetic liner.
- Pits sidewall slopes range from 2:1 to 3:1.

2.1.9 Discussion of Pit Specifications

The well sites observed in PA by Alpha during the course of this review relied on excavated pits for drilling only. These were large, synthetic lined pits capable of handling cuttings and fluid from multiple wells. No frac fluids were discharged to the open pit. The frac and flowback fluids were circulated through a closed loop system using steel tanks. NYS may consider the use of flowback impoundments for future operations similar to the centralized impoundments being used in Pennsylvania as described in section 2.1.5.

New Mexico's required separation of 50 feet from ground water is not a realistic application in New York. Even the implementation of a pit bottom depth requirement of 20 inches above the seasonal high water table might be problematic for some situations if applied in New York. Seasonal high water tables approaching land surface can and will occur in many locations even in upland areas of low permeable glacial tills. Considerations need to be given to the nature of the unconsolidated material and the water table if a 20-inch rule is applied. A floating liner would be an issue in lowland areas with high rates of inflow from medium- to high-permeability soils. This may not be a significant concern in upland till covered areas. This issue may be best handled with flexibility and engineering judgment.

The existing GEIS for New York, which was finalized in 1992, recommends the use of synthetic liners due to limitations in confirming appropriate permeability of native soils and concerns for chemistry of production fluids. Potential issues from production and flowback fluid leakage can be minimized by requiring that those fluids be circulated directly to steel tanks in a closed loop system, as is the current practice in PA and the City of Fort Worth. The excavated pits in PA are used only for the drilling mud returns from which mud additives, such as bentonite, are reclaimed for reuse. The pits observed in Pennsylvania by Alpha would contain mostly formation cuttings when the pits are closed and the fluids are removed; consequently, leakage does not pose an environmental threat. The option for a compacted soil liner with a maximum permeability of 1×10^{-7} cm/sec may be suitable for some situations. Drill cuttings from air-drilled wells may be buried onsite in accordance with the 1992 GEIS. The SGEIS should address allowable methods for handling and disposing cuttings from mud-based drilling operations, including the possibility of burial in drill pits.

Requirements for maintaining 2 feet of freeboard for the fluid level in the pit and diverting surface water away from the pit are effective means of minimizing overtopping and release of fluids. Maintaining fluid levels in the pits is easily achieved by modern drilling techniques that recondition and reuse drilling fluids. Pit liners with thicknesses in the range of 20 mil (NM) and 30 mil (PA) are less likely to rupture or tear than liners as thin as 6 mil that may be used in NY based on the 1992 GEIS. A thicker liner would form a more dependable fluid barrier for the larger pits and the longer durations of use for multi-well sites; however, consideration should be given to the disposition of these liners during closure, as discussed in the following section on pit reclamation.

2.2 Reclamation and Waste Disposal

Most of the available documents and information on reclamation and waste disposal pertains to general oil and gas regulations with very little focus on horizontal drilling and high volume hydrofracturing. The following summaries contain information that might be of value for the dSGEIS in NYS.

2.2.1 Arkansas

- Fresh water drilling fluids can be disposed by land application (permit required), disposal well injection, on-site disposal by mixing with native soils, or by disposal back in the well (approval required).
- Fluids must be removed from the pit to the maximum extent practical.
- The synthetic liner must be removed to the maximum extent practical and properly disposed or recycled.
- The mud left in the pit must contain less than 3 percent, by weight, of oil and grease.
- The drilling mud should be mixed with a stabilizing agent such as kiln dust or fly ash. The regulatory agency must be notified of the amount and type of stabilizing material to be used at least ten days prior to use.
- The mud must be covered and backfilled with native materials and topsoil graded back to the original contour.
- The pit must be reclaimed within 180 days after the rig has left the site, and the vegetation cover must be at least 75 percent established within 6 months after closure. A statement of disposition must be provided within 90 days following closure.
- Where oil-based muds are used, all contents from pits must be removed and disposed in accordance with state regulations.

2.2.2 Colorado

- Pits not used for drilling purposes must be closed in accordance with an approved Site Investigation and Remediation Workplan.
- Synthetic liners must be removed and disposed in accordance with applicable legal requirements for solid waste disposal.
- Constructed soil liners may be removed for treatment or disposal, or the liner may be mixed with native soils to prevent the formation of an impermeable barrier.
- Drilling pits are to be reclaimed within three months after cessation of drilling and completion activities on croplands or within 100-year floodplains, and within six months

on all other land. Bentonite-based drilling fluids in pits must be removed and disposed in accordance with appropriate waste disposal regulations. These regulations allow for on-site drying in pits or land spreading with regulatory and landowner permission. Regulatory approval is not required for reuse of fluids for soil amendments.

- Drill cuttings in pits, which are on croplands or within 100-year floodplains, can be left in the pit but must remain in a manner that does not form an impermeable barrier. The native soils are to be backfilled to their original relative positions.
- Drill cuttings in pits on non-croplands must be backfilled in a manner that does not result in the drilling mud being squeezed out of the pit and incorporated into the soils at the land surface.
- A minimum cover of three feet of soil must be placed over the pit centers in cropland.
- If subsidence occurs within the backfilled pit within two years after reclamation, then additional soil must be placed on top to bring the surface back to its original level.

2.2.3 Louisiana

- The operator must file a report to the agency within six months after completion of well activities to declare the types and number of barrels of exploration and production waste generated, to report the disposition of the waste, and to certify the appropriate disposal of that waste.
- Pits must be emptied of produced fluids during periods of non-use within 30 days after operations have ceased.

2.2.4 New Mexico

The reclamation requirements for New Mexico are among the most stringent for the states reviewed. These requirements include:

- All fluids must be removed and either recycled, reused or disposed in accordance with state regulations.

- All solids and the liner should be removed and sent to a disposal facility in accordance with state regulations.
- New Mexico regulations state that the operator must sample the soil below the pit and "analyze for benzene, total BTEX, TPH, the GRO and DRO combined fraction and chlorides". These sampling requirements and threshold values vary depending on the depth to ground water.
- If the soil investigation proves that no contamination has occurred, then the pit can be backfilled with an approved, non-waste bearing earthen material, re-contoured, and vegetated with regulatory approval.
- Alternate closure approaches can be utilized with regulatory approval.
- The operator must provide notice of the pit closure method to the landowner and provide proof of notice to the regulatory agency.
- If the closure method involves on-site burial, then the operator must place a steel marker at the center of an on-site burial. The marker must be at least 4 inches in diameter, extend 4 feet above grade, and be cemented in a 3-foot hole. The marker will include the operator's name, lease name, well number, location, and notice that the site represents subsurface burial.
- The operator must file a notice of on-site burial with the regulatory agency and with the deed in the county clerk's office.
- The buried waste must be stabilized or solidified to a bearing capacity that will support the final cover.
- The contents of buried waste, which may include waste from closed-loop systems, and stabilizing agent, must be tested for TPH, benzene, BTEX, chloride, DRO, and GRO.
- Pit contents must be removed from a pit within 30 days after the date the rig has been released, and the pit site reclaimed within 6 months of the date with an option to obtain one 3-month extension.

2.2.5 Pennsylvania

- Pits must be closed within nine months after operations have ceased.

- Liquid waste must be removed from the pits and cannot be discharged to waters of the Commonwealth unless it complies with regulatory limits.
- Uncontaminated drill cuttings can be left in the pit or spread on the land surface provided the ground is not saturated, frozen or snow covered. Contaminated cuttings, which are cuttings that exceed PA regulatory limits for toxicity characteristics, can be left in the pit and covered by folding over the existing unpunctured liner or adding a liner shaped to prevent infiltration. The pit is then backfilled to grade with soil materials.
- Land application of uncontaminated cuttings requires a regulatory notification of at least three days prior to spreading and must follow PA guidelines.

2.2.6 City of Fort Worth

- All drill pits and contents must be dewatered.
- No drill cuttings, rotary mud or waste water generated during drilling operations may be buried on site unless permitted by the regulatory agency (Railroad Commission of Texas (TXRRC)) and approved by the City.
- The operator must have an agreement with the landowner regarding the disposition of the fracturing pit; otherwise, the operation must return the land to its original condition.
- No flowback water produced by fracture operations can be placed in an open pit without a state permit submitted to the City Gas Inspector.
- The operator may not deposit or discharge any refuse, waste water or brine onto any City or private property without City permits.
- The use of fresh water pits for the disposal of liquids other than fresh water requires a City permit.

2.2.7 West Virginia

- The operator must fill in all pits, and re-grade and vegetate the surface of all disturbed land not needed for well production within six months after completion of the development of the well.

- All salt water must be periodically drained and properly disposed from any pit that is retained.

2.2.8 Discussion of Reclamation and Waste Disposal

The regulatory survey revealed that very few rules and regulations regarding reclamation and waste disposal have been developed to specifically address the unconventional gas development. The most relevant regulations were developed for the City of Fort Worth, Texas to address drilling in urban areas of relatively high population density. Additional relevant information can be developed from observation of the best management practices of the operations in northern PA.

The wastes generated from drilling and fracing in northern PA consist primarily of the flowback water from fracing, production water associated with gas production, and the mud returns (fluids and cuttings) derived from drilling. The practice observed at Pennsylvania drilling sites is for the frac flowback to be contained in a closed system that captures the water in steel frac tanks. Future operations in Pennsylvania, and possibly in New York, may include use of centralized impoundments or lined onsite pits to store flowback water prior to treatment and/or reuse. This water is either treated on site or transported to an off site location for treatment. The treated water is reused for fracing and the concentrate is disposed or further treated for beneficial use or disposal in accordance with PA regulations. These wastes can either be disposed in landfills or injected into disposal wells. The produced water also is transported off site and processed at a DEP-permitted facility and disposed in a manner in accordance with PA regulations. .

Drilling up to eight deep borings with long horizontal extensions through the production zones generates a large volume of mud returns at a given multi-well site. These returns circulate through a system that typically includes a large, lined pit and a series of metal tanks with baffles and other equipment to remove cuttings and suspended solids and to recondition the fluid. The sands and fines - which are removed by de-sanders and other clarifiers, along with the cuttings - are routed to the lined pit. The solids can be left in the pit and closed in accordance with PA regulations when drilling is completed if the solids do not contain constituents at levels that exceed PA environmental standards.

All other wastes, such as sewage and putrescible waste generated by the on-site work force, is containerized for transport off site to a regulated sewage treatment plant or landfill, as appropriate. The site best-management practices also are in place to capture inadvertent releases of petrochemicals used in the drilling process. These include secondary containment structures around petroleum storage tanks and lined trenches to direct fluids to lined sumps where spills can be recovered without environmental contamination.

Those portions of the site that are not necessary to support the producing gas wells are reclaimed by backfilling the pits, grading the site, and establishing a vegetative cover. The pits are backfilled after the remaining fluids are removed and the cutting are either removed or encapsulated in accordance with PA regulations.

The reclamation approach and regulations being applied in PA may be an effective analogue going forward in New York. The site control, treatment and recycling of drilling fluids has been effective. The on site handling, treatment and removal of frac flowback and production water also has been effective, but the options for ultimate disposal of high TDS flowback and production water remain issues in PA and must be addressed as drilling activity increases in northern PA and NY. The Marcellus Shale Committee is working with the Appalachia Shale Water Management Committee, a consortium of wastewater treatment experts, to research water use, recycling, treatment and disposal options (Marcellus Shale Committee, July 22, 2009). Deep well injection and landfill disposal are options in PA, but are not readily available options in NY, unless PA has the capacity to handle the increased volume from both NY and PA. Techniques exist and are being further developed to treat recycling fluids that have high levels of TDS. These methods can extract fresh water and produce a concentrate that can be disposed in a controlled and proper manner or, if meeting applicable safety and environmental criteria, considered for beneficial use, such as deicing or dust control, or production of salt.

The disposition of the pit liner is one issue that may need further consideration. Removing the liner may be difficult if the drill cuttings are left in the pit. The liner could form an impermeable barrier if left in the pit, and may result in a large mass of low strength soil material if the liner is folded over to encapsulate the mud. Perforating or ripping the liner in situ to prevent the formation of an impermeable barrier is a standard practice in New York to prevent the creation of unstable soil, or the formation of a localized area of poor soil drainage. Consideration also should be given to monitoring and mitigating subsidence by adding fill as the drill cuttings dewater and consolidate.

The timing of pit closure is another important issue due to the variability in rates of site completion. The operators in PA would prefer to drill all of the planned wells at a pad (6 to 8 wells maximum) during a single rig mobilization; however, the operators may elect to mobilize more than once before drilling all of the wells at a site. This may necessitate allowing the temporary pits to remain open for an extended period, provided adequate controls (e.g., secure fencing) are in place to protect human health and safety, maintain adequate freeboard and liner integrity, and protect wildlife and farm animals. An adequate fencing requirement with posted emergency contact information and periodic inspections would be appropriate for times when pits may be open and the site is unattended. In addition, it may be desirable to require the removal of pit fluids if there is an extended period of time between the drilling of wells.

2.3 Water Well Testing Requirements

Several of the states surveyed have water well testing requirements. Some of those regulations, such as Colorado and Fort Worth, Texas, appear to be directed to unconventional gas development within a targeted region of the respective states. Most of the remaining state requirements are for oil and gas development throughout the respective states without preference to unconventional gas development. All of these regulations are summarized herein regardless of intent.

2.3.1 Colorado

Colorado has special regulations for drilling specifically through the Laramie Fox Hills Aquifer in the Greater Wattenbery area and also for unconventional coal bed methane (CBM) wells. A general summary of the rules is as follows:

- A baseline sample must be collected from the nearest well in the Laramie Fox Hills Aquifer that is within 0.5 mile of an oil and gas infill well. This sample must be tested for all major cations, anions, total dissolved solids, iron, manganese, nutrients (nitrates, nitrites, selenium), dissolved methane, pH, and specific conductance. If the methane or free gas concentration is encountered at a level greater than 2 mg/l, then a compositional analysis must be run to determine gas type (thermogenic, biogenic or both). If the result is biogenic, then no further testing is required. If the result is thermogenic or a mixture, then carbon isotopic analysis of the methane must be conducted. Copies of all results must be provided to the landowner and the regulatory agency within three months.

- Water well monitoring related to CBM wells is a complicated process associated with the presence of conventional gas wells. The process and the extensive analytical requirements do not appear relevant to unconventional gas development in New York. The details of the CBM monitoring requirements are presented in Table 2.2.

2.3.2 Louisiana

Louisiana does not require or provide recommendations for baseline monitoring; however, they require that the results of any voluntary environmental sample be supplied to the private landowner within ten days of the receipt of the result. The state also requires the submittal of the results to the regulatory agency if it involves an exploration and production site.

2.3.3 Ohio

- Operators must sample all water wells within 300 feet of the proposed well location prior to drilling within urbanized areas. The baseline sampling is to be conducted following the guidance of a best management practices (BMP) developed by the State of Ohio.
- The baseline sample is to be tested for dissolved Ba and Fe (µg/l); total Ca, Mg, K and Na (mg/l); Cl, SO_4, Alkalinity, and TDS (mg/l); and pH and conductivity (µmhos/cm at 25° C).

2.3.4 Pennsylvania

Pennsylvania does not require pre-drilling baseline monitoring of water wells; however, voluntary pre-drilling sampling of existing wells is recommended to protect the operator's interest. This recommendation is predicated on the law that the operators must replace water supplies damaged by exploration and development activities, and that the operator is presumed to be the cause of adverse water quality impacts that appear in a well within six months of the completion of an exploration and production well. The following water well testing is recommended by PA:

- Monitor the quality of any water supply within 1,000 feet of a proposed drilling operation;
- Analyze the water samples using an independent, state certified, water testing laboratory; and
- Analyze the water for Na, Cl, Fe, Mn, Ba and As. Also analyze for coliform bacteria, methane and organics, if warranted by the circumstance.

2.3.5 City of Fort Worth

The City of Fort Worth has developed water well testing requirements specifically for the unconventional gas drilling play in the underlying Barnett shale. The city requires monitoring both quantity and quality for baseline (pre-drilling) and also after the gas well is completed. This testing is for all fresh water wells within 500 feet of both proposed and completed gas wells. The distance between wells is measured from the boring centers at the ground surface. No water quality analytical parameters are required by the City of Fort Worth gas drilling ordinance.

The analytical parameters monitored usually include total petroleum hydrocarbons, benzene-toluene-xylene, and volatile organic compounds for the purpose of determining a background of parameters normally associated with drilling prior to the commencement of operations and to monitor for post drilling contamination. Other analytes are determined on a case-by-case basis (April Lawler, City of Fort Worth Gas Well Section, personal communication, July 23, 2009).

2.3.6 West Virginia

- For an owner who requests a test, the operator will test one fresh water well or spring within 1,000 feet of the proposed oil and gas well. The water supply can be for human consumption, animal consumption, or for general uses.
- If there is no property owner request, then the operator must select one well or spring within 1,000 feet that the operator considers having the highest potential for influence from the operators well.
- If no water supply is available within 1,000 feet, the operator may be directed by the regulatory agency to sample a well or spring between 1,000 and 2,000 feet of the operator's well.
- The operator has the discretion to sample all wells and springs within 1,000 feet of the proposed oil and gas well.
- The operator must give notice to the property owner or the user of the supply to have the water supply sampled by the operator.
- The operator is required to mail or post a notice to alert the water supply owners within 1,000 feet. This notice and the contact approach must be approved by the state.
- The notice must be given at least 48 hours before commencement of drilling.
- The operator must provide the state with a statement identifying those water users that were identified and how they were identified.

- The sampling procedure must be approved by the regulating agency.
- The analyses must include pH, Fe, TDS, Cl, detergents and any other parameters desired by the operator.
- The results must be provided within 30 days after receipt of the results to the regulating agency and any owner of a water supply who requested sampling.

2.3.7 Discussion of Water Well Testing Requirements

Several of the operators that are active in northern PA and the southern tier of NY are applying the voluntary water well monitoring system recommended by PA. These operators are sampling all available, potable water supply wells within 1,000 feet of the proposed well site. These wells are sampled for routine water supply parameters that may include Cl, oil and grease, and surfactants.

Baseline water well monitoring is an effective program that is a benefit to both the public and the operator. The public is provided with a mechanism to prove impact that is paid by the operator, and the operator is provided with a means of defense against unsubstantiated or frivolous claims. The methodology used in Pennsylvania of monitoring all water supply wells within 1,000 feet of a gas exploration/development well, as long as permission has been granted, should be effective in addressing potential impacts. At least one of the operators in PA expands the monitoring network to 2,000 feet at those drilling sites where no wells are available within 1,000 feet. A simple list of parameters that includes methane types, TDS, chlorides and pH may be sufficient with other parameters added at the discretion of the operator.

2.4 Fracturing Fluid Reporting Requirements

Wyoming is the only state that requires that the operator notify the state regulatory agency of the details of a completed fracturing job. Wyoming requires a report (Form 3, Well Completion or Recompletion Report and Log) of any fracturing and any associated activities such as shooting the casing, acidizing and gun perforating. The report is required to contain a detailed account of the work done; the manner undertaken; the daily volume of oil or gas, and water produced, prior to, and after the action; the size and depth of perforation; the quantity of sand, chemicals and other material utilized in the activity; and any other pertinent information.

None of the other states reviewed require any reporting on completed fracturing projects. None of the states, including Wyoming, require a report on the composition of the flowback water.

2.5 Hydraulic Fracturing Operations

West Virginia, Wyoming, Colorado, and Louisiana require notification or approval prior to conducting hydraulic fracturing of a well and/or a report to be filed following fracturing or related operations. New Mexico requires a report of underground damage that may result in contamination.

2.5.1 West Virginia

West Virginia requires a permit for fracturing or stimulation of an existing well. These actions are part of the well drilling permit if it is a new well. The operator is required to provide a notification of intent to fracture to the regulatory agency and the operators of all coal mines beneath the affected tract of land. The notification must be by registered or certified mail. A permit to fracture will be issued if there are no complaints within fifteen days after receipt of the notice by the state regulating agency.

2.5.2 Wyoming

Wyoming Oil and Gas Commission Rules require pre-approval for hydraulic fracturing treatments of a well. The operator must provide detailed process information on Form 1, Application for Permit to Drill, and also often provide this information on Form 4, Sundry Notice. The hydraulic fracture stimulation information includes the depth to perforations or to the open hole interval, the water source and/or trade name of fluids, the proppants, and the estimated pump pressure.

2.5.3 Colorado

The Colorado Oil and Gas Conservation Commission (COGCC) requires that the operator must deliver a written notice of subsequent well operations, including hydraulic fracture stimulation, to the surface owner no less than seven days prior to the estimated start of operations with heavy equipment. The COGCC also requires that the well operator submit a Completed Interval Form (Form 5A) within 30 days of the completion of an interval (whether successful or not), including recompletion, reperforation, restimulation, or commingling.

2.5.4 Louisiana

Louisiana requires the filing of a permit (MD-11R) prior to, and a report (Form WH-1) within 20 days after, well perforation, directional drilling, plugging back, acidizing, and other operations that are often necessary processes in wells that are to be or have been hydraulically fractured.

2.5.5 New Mexico

New Mexico requires that an operator notify the Natural Resources Division within five working days if damage to the producing formation, injection interval, casing, or casing seat that may create underground waste or fresh water contamination results from shooting, fracturing, or treating a well. The operator must also proceed with the rectification of such damage and submit the relevant information on a Well Completion or Recompletion Report (Form C-105).

2.6 Fluid Use and Recycling Requirements

Several states regulate surface water withdrawals for oil and gas well development, but very few address the reuse or recycling of fluids or use of treated municipal water as a source fluid. These various aspects of water use are addressed separately herein for convenience.

2.6.1 Surface Water Withdrawal

Several states, or interstate agencies within some states, regulate surface water withdrawals. These withdrawals are for all aspects of oil and gas well development from drilling through fracing. The various rules for each state are discussed separately.

2.6.1.1 Louisiana

- Activities in uplands or upstream of coastal water and wetlands must preserve or enhance water quality/volumes and rates of flow. This regulation is intended to guide activities such as surface water removal.
- A permit is required for the consumptive use of water in the coastal zone.
- The regulation also discourages the use of the Carizzo-Wilcox aquifer if ground water is taken for oil and gas well development.

2.6.1.2 Ohio

The surface water use restrictions for Ohio pertain only to the Ohio River and the drainage basin for Lake Erie where a permit is required for any removal of larger than 100,000 gallons per day. The allowable volume can be reduced at the discretion of the regulating agency.

2.6.1.3 Pennsylvania

A Water Management Plan must be submitted to the Pennsylvanian regulatory agency prior to each Marcellus shale gas development project. These plans require notification of the municipality and county where the project water will be sourced. The Delaware River Basin Commission (DRBC) or the Susquehanna River Basin Commission (SRBC) must also be notified of the source if the project is within one of those jurisdictions. The appropriate notifications must be completed prior to submission of the plans. Permits must by obtained from the DRBC or SRBC for water withdrawals (surface water and ground water) if the water is being sourced in one of those basins. These permits are to be included as part of the PA Water

Management Plan. The State of Pennsylvania does not appear to require any withdrawal permits.

2.6.1.4 West Virginia

Surface water withdrawal regulations for West Virginia are general in nature and are not specifically tailored to the oil and gas industry. The following are the requirements and regulations:

- An operator must register with the State and document quantities removed if more than 750,000 gallons are withdrawn from a source in a one month period. An operator that reports more than 750,000 gallons per month on an annual basis for three years can cease registering if the amount withdrawn does not vary more than 10 percent from a three year average.
- An operator must not withdraw more than 10 percent of what a ground water or surface water source can sustain.
- The operator will limit the withdrawal to less than 10 percent of a stream flow during low flow.
- The operator must seek larger streams and avoid headwater streams during drier months.
- The operator must contact the state regulatory agency to obtain low flow information for streams.
- The construction of large holding ponds to collect water during high flows is recommended.
- Stream access for pumping must be carefully considered.

2.6.1.5 Wyoming

Surface water use controls for oil and gas drilling in Wyoming are very limited with respect to quantity. These regulations are as follows:

- The right to divert or store water can be obtained by filling out a Water Agreement for Temporary Use of Water Form.
- The permission to divert water is limited to a 2-year period.

2.6.1.6 Discussion of Water Withdrawals

The most stringent rules for surface water withdrawals are in Pennsylvania due to the presence of the Delaware and Susquehanna River Basins. The DRBC and SRBC require, at a minimum, withdrawal permits and monitoring to maintain flows. These withdrawal permits pertain to both ground water and surface water. Both of these basins are present in parts of New York, and any drilling in these basins will require the same permitting process, unless the regulations established by NYS are more stringent than those already established by the basin commissions. Portions of the Marcellus Shale and other shale gas formations lie outside both the SRBC and DRBC.

2.6.2 Use of Treated Municipal Water

None of the states surveyed have any requirements, rules or guidance relating to the use of treated municipal waste water. Likewise, none of the operations in northern PA that were observed by Alpha were using treated municipal waste water at the time this report was prepared.

2.6.3 Requirements for Treatment, Recycling and Reuse of Drilling or Frac Fluids

Ohio and West Virginia are the only states that address treatment, recycling, and reuse of fluids. Ohio allows the reuse of drilling and fracing fluid for dust and ice control with an approval resolution. Ohio also will consider approval of other options depending on technology. All options must be protective of water resources and the environment. West Virginia restricts its comments on treatment, reuse, and recycling to a recommendation that operators should consider recycling frac flowback water.

Some of the operators in northern PA also are actively treating and recycling drilling and fracing fluids on a voluntary basis without a regulatory requirement. Most of the cuttings and fines are separated from the drilling mud returns and disposed, and the drilling muds, including additives, are reused. The solids typically are left in the pit excavation and are covered in accordance with PA regulations. The remaining fluid is removed for subsequent reuse at other drilling sites or transported off site for proper disposal.

The operations in northern PA also are recycling the majority of the frac fluids. These fluids are treated onsite to reduce TDS levels below 30,000 ppm. The fluids are used for the next fracing project where the recycled water is diluted by mixing with fresh makeup water. The concentrate from the onsite treatment is transported off site and disposed in accordance with PA regulations and approvals (see section 2.2.8 for discussion of this topic). The ability of the operators to maintain this recycling and reuse approach will become more apparent as the frequency of well drilling and fracing increases in PA.

2.7 Materials Handling and Transport Requirements

Regulations that reference "DOT-approved" trucks or containers that are applicable to the transportation and storage of hazardous frac additives refer to federal (USDOT) regulations for registering and permitting commercial motor carriers and drivers, and established standards for hazardous containers. The United Nations (UN) also has established standards and criteria for containers. New York is one of many states where the state agency (NYDOT) has adopted the federal regulations for transporting hazardous materials interstate. The NYSDOT has its own requirements for intrastate transportation.

Transporting frac additives that are hazardous is comprehensively regulated under existing regulations. The regulated materials include the hazardous additives and mixtures containing thresholds of hazardous materials. These transported materials are maintained in the USDOT or UN-approved storage containers until the materials are used at the drill sites.

2.7.1 USDOT Transportation Regulations

The federal Hazardous Material Transportation Act (HMTA, 1975) and the Hazardous Materials Transportation Uniform Safety Act (HMTUSA, 1990) are the basis for federal hazardous materials transportation law (49 U.S.C.) and give regulatory authority to the Secretary of the USDOT to:

- "Designate material (including an explosive, radioactive, infectious substance, flammable or combustible liquid, solid or gas, toxic, oxidizing, or corrosive material, and compressed gas) or a group or class of material as hazardous when the Secretary determines that transporting the material in commerce in a particular amount and form may pose an unreasonable risk to health and safety or property; and
- Issue regulations for the safe transportation, including security, of hazardous material in intrastate, interstate, and foreign commerce", (PHMSA, 2009).

The Code of Federal Regulations (CFR), Title 49, includes the Hazardous Materials Transportation Regulations, Parts 100 through 199. Federal hazardous materials regulations include:

- Hazardous materials classification (Parts 171 and 173);
- Hazard communication (Part 172);
- Packaging requirements (Parts 173, 178, 179, 180);
- Operational rules (Parts 171, 172, 173, 174, 175, 176, 177);
- Training and security (part 172); and
- Registration (Part 171).

The extensive regulations address the potential concerns involved in transporting hazardous frac additives, such as General Requirements for Shipments and Packaging (Part 173), Loading and Unloading (Part 177), Specifications for Packaging (Part 178), and Continuing Qualification and Maintenance of Packagings (Part 180).

Regulatory functions are carried out by the following USDOT agencies:

- Pipeline and Hazardous Materials Safety Administration (PHMSA);

- Federal Motor Carrier Safety Administration (FMCSA);
- Federal Aviation Administration (FAA); and
- United States Coast Guard (USCG).

Each of these agencies shares in promulgating regulations and enforcing the federal hazmat regulations. State, local, or tribal requirements may only preempt federal hazmat regulations if one of the federal enforcing agencies issues a waiver of preemption based on accepting a regulation that offers an equal or greater level of protection to the public and does not unreasonably burden commerce.

The interstate transportation of hazardous materials for motor carriers is regulated by FMCSA and PHMSA. FMCSA establishes standards for commercial motor vehicles, drivers, and companies, and enforces 49 CFR Parts 350-399. FMCSA's responsibilities include monitoring and enforcing regulatory compliance, with focus on safety and financial responsibility. PHMSA's enforcement activities relate to "the shipment of hazardous materials, fabrication, marking, maintenance, reconditioning, repair or testing of multi-modal containers that are represented, marked, certified, or sold for use in the transportation of hazardous materials." PHMSA's regulatory functions include issuing Hazardous Materials Safety Permits; issuing rules and regulations for safe transportation; issuing, renewing, modifying, and terminating special permits and approvals for specific activities; and receiving, reviewing, and maintaining records, among other duties.

2.7.2 New York State DOT Transportation Regulations

New York State requires all registrants of commercial motor vehicles to obtain a USDOT number. New York has adopted the FMCSA regulations CFR 49, Parts 390, 391, 392, 393, 395, and 396, and the Hazardous Materials Transportation Regulations, Parts 100 through 199, as those regulations apply to interstate highway transportation (NYSDOT, 6/2/09). There are minor exemptions to these federal regulations in NYCRR Title17 Part 820, "New York State Motor

Carrier Safety Regulations"; however, the exemptions do not directly relate to the objectives of this review.

The NYS regulations include motor vehicle carriers that operate solely on an intrastate basis. Those carriers and drivers operating in intrastate commerce must comply with 17 NYCRR Part 820, in addition to the applicable requirements and regulations of the NYS Vehicle and Traffic Law and the NYS Department of Motor Vehicles (DMV), including the regulations requiring registration or operating authority for transporting hazardous materials from the USDOT or the NYSDOT Commissioner.

Part 820.8 (Transportation of hazardous materials) states "Every person … engaged in the transportation of hazardous materials within this State shall be subject to the rules and regulations contained in this Part." The regulations require that the material be "properly classed, described, packaged, clearly marked, clearly labeled, and in the condition for shipment…" [820.8(b)]; that the material "is handled and transported in accordance with this Part" [820.8(c)]; "require a shipper of hazardous materials to have someone available at all times, 24 hours a day, to answer questions with respect to the material being carried and the hazards involved" [820.8.(f)]; and provides for immediately reporting to "the fire or police department of the local municipality or to the Division of State Police any incident that occurs during the course of transportation (including loading, unloading and temporary storage) as a direct result of hazardous materials" [820.8 (h)].

Part 820 specifies that "In addition to the requirements of this Part, the Commissioner of Transportation adopts the following sections and parts of Title 49 of the *Code of Federal Regulations* with the same force and effect… for classification, description, packaging, marking, labeling, preparing, handling and transporting all hazardous materials, and procedures for obtaining relief from the requirements, all of the standards, requirements and procedures contained in sections 107.101, 107.105, 107.107, 107.109, 107.111, 107.113, 107.117, 107.121, 107.123, Part 171, except section 171.1, Parts 172 through 199, including appendices, inclusive and Part 397.

2.7.3 NYSDEC Programs for Bulk Storage

Operators of gas drilling sites or service companies will temporarily store chemical additives for hydraulic fracturing operations. The storage may take place for durations of days or possibly weeks. Additives that are hazardous, or contain hazardous constituents above specific thresholds, are stored in the same shipping containers that meet the USDOT and/or UN criteria. The operators and service companies maintain the storage of hazardous materials until the materials are transferred to the point of application. The transfer of hydrofracing materials is monitored by qualified personnel, and devices such as manual valves provide additional controls when liquids are transferred. Alpha observed other common practices during visits to drill sites in PA that included lined containments and protective barriers.

The NYSDEC regulates bulk storage of petroleum and hazardous chemicals under 6 NYCRR regulations, Parts 612-614 for Petroleum Bulk Storage (PBS) and Parts 595-597 for Chemical Bulk Storage (CBS). The PBS regulations do not apply to non-stationary tanks and petroleum is not used as a hydrofracing additive; however, all petroleum spills, leaks, and discharges must be reported to the NYSDEC (613.8). Although not a specific regulation, an interpretation of the NYSDEC PBS program may deem that a non-stationary petroleum tank of 1100 gallons or greater that is stored on site more than 90 days may be subject to registration and regulatory requirements for above-ground storage tanks (ASTs), (NYSDEC personal communication, June 2009).

The CBS regulations that potentially may apply to hydrofracing fluids include non-stationary tanks, barrels, drums or other vessels that store 1000 kg or greater for a period of 90 consecutive days. Liquid frac chemicals are stored in non-stationary containers but most likely will not be stored on-site for 90 consecutive days; therefore, those applicable chemicals are exempt from Part 596, "Registration of Hazardous Substance Bulk Storage Tanks" unless the storage-period criterion is exceeded. These liquids typically are trucked to the drill site in volumes required for consumptive use and only days before the hydrofracing process. Dry chemical additives, even when stored on site for 90 days, are exempt from 6 NYCRR because the dry materials are stored in 55-lb bags secured on plastic-wrapped pallets.

The facility must maintain inventory records for all applicable non-stationary tanks including those that do not exceed the 90-day storage threshold. The CBS spill regulations and reporting requirements also apply regardless of the storage thresholds or exemptions. Any spill of a "reportable quantity" listed in Part 597.2(b), must be reported within 2 hours unless the spill is contained by secondary containment within 24 hours and the volume is completely recovered. Spills of any volume must be reported within two (2) hours, if the release could cause a fire, explosion, contravention of air or water quality standards, illness, or injury.

2.7.4 USEPA Reporting

The Emergency Planning and Community Right-to-Know Act (EPCRA, 1986), requires facilities storing more than 10,000 pounds of hazardous chemicals to report an inventory of those materials to state, local, and fire officials, and make available Material Safety Data Sheets (MSDS). The MSDS documents contain the manufacturer's information regarding physical and chemical properties, exposure information, and emergency responses, among other data.

A few frac chemicals, such as hydrochloric acid, are considered hazardous under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA 1980). These materials may be stored temporarily during fracturing operations. EPCRA Section 304 requires reporting releases to the environment of specific materials including petroleum that exceed thresholds ("reportable quantities") regardless of its exemption under CERCLA. The operator/service company is required to report to federal, state, and local agencies the release of any listed chemical above thresholds to the air, surface water, or ground water.

2.7.5 Summary

It is clear that the motor transport of all hazardous hydrofracing additives or mixtures to drill sites is adequately covered by the existing federal and New York State DOT regulations. It is recommended that regardless of exemption or regulatory status, the temporary on site storage of hydrofracing additive chemicals (and petroleum) comply with accepted best management practices (BMPs) for handling and spill containment,. These practices may include, as appropriate to the specific containers, monitoring and recording inventories; manual inspections; berms or dikes, secondary containment; monitored transfers, storm water runoff controls, mechanical shut-off devices, setbacks, physical barriers, and materials for rapid spill cleanup and recovery.

2.8 Requirements for Minimizing Potential Noise and Lighting Impacts

Noise and lighting impacts are derived primarily from the larger well site pads and larger duration of site activity compared with conventional drilling. The equipment on site (Table 2.11) is similar to conventional drilling; however, the drilling rigs are often larger and there are more trucks and tanks involved in the site activity for unconventional drilling. Three of the states and the City of Fort Worth have regulations or recommendations for the mitigation of noise and lighting impacts. The City of Fort Worth has the most extensive set of regulations, and Ohio recommends that mitigation be done, but has no actual requirements. Noise and light mitigation are treated separately herein for clarity.

2.8.1 Mitigation of Noise Impacts

2.8.1.1 Colorado

Colorado has set noise level limits for specific zones during the time period between 7:00 am and 7:00 pm, as shown below. These regulations allow an increase of 10 db(A) for not more than a 15 minute period within each hour for each zone. The allowable limit is reduced by 5 db(A) for impulsive or shrill noises.

ZONE	**7:00 am to next 7:00 pm**	**7:00 pm to next 7:00 am**
Residential/Agricultural/Rural	55 db(A)	50 db(A)
Commercial	60 db(A)	55 db(A)
Light Industrial	70 db(A)	65 db(A)
Industrial	80 db(A)	75 db(A)

The light industrial standard applies for remote locations. The regulations provide guidance for measurement of the sound level. Colorado also requires:

- A sound level measurement within 25 feet of the exterior wall of a residence or occupied structure from which a complaint has been filed and if a site inspection has revealed that a low frequency noise is a component of the issue. The measurement will be made with a meter calibrated to the db(c) scale. If the reading exceeds 65 db(c), then the operator will be required to obtain a low frequency analysis by a qualified sound expert who will develop a plan to mitigate the low frequency noise.
- Exhaust from all engines, motors, coolers and other mechanized equipment must be vented in a direction away from all building units.
- All engines and motors, which are not electrically operated, will be equipped with quiet design muffler or equivalent if they are within 400 feet of building units.

2.8.1.2 Louisiana

Louisiana requests that:

- The operator establishes a continuous 72 hour ambient noise level at the site prior to commencement of any operations. This evaluation must include at least one 24-hour reading on a Saturday or Sunday. The meter utilized must meet, or be equivalent to, the standards of the American National Standard Institute. Documentation must be maintained by the operator and be available to the regulatory agency upon request.
- Exterior noise levels at a distance of 500 feet from the well site will not be allowed to exceed: the 72 hour ambient level by more than 7 decibels during the day and 5 decibels at night; the average daytime average ambient level by more than 10 decibels during fracturing or flowback operations; or the 72 hour ambient level by more than 5 decibels during flowback operations at night.
- Adjustments to the aforementioned noise standards can be made to allow an increase of 5 db(A) for a cumulative total of 10 minutes per hour, 1 db(A) for 15 minutes per hour, and less than 1 db(A) for 20 minutes per hour.

- The operator must periodically monitor exterior noise levels within 500 feet of a noise at the site.
- The operator must monitor exterior noise levels 500 feet from the noise source within 24 hours of receiving a complaint originating from a residence or public building that is within 750 feet of a wellhead.
- No compliance order will be issued by the regulatory agency until it has been determined by the inspector that a violation has occurred and the operator has been given 24 hours from the receipt of the notification to correct the issue. Additional extensions may be granted if the violation cannot be identified after reasonable diligence by the operator.

2.8.1.3 Ohio

There are no specific noise monitoring or abatement measures required by the State of Ohio. According to the contact at the regulatory agency, Ohio specifies that well drilling, service and maintenance be conducted in a manner that mitigates noise.

2.8.1.4 City of Fort Worth

The City of Fort Worth has specific noise level requirements and also sets general work hour and day of the week guidelines for minimizing noise impacts. The following are the noise level requirements:

- A noise management plan is required as part of the gas well permit. This plan includes the identification of noise impacts, the establishment of an ambient noise level (ANL) based on 72 hours of pre-drilling monitoring with at least one 24 hour period over a Saturday or Sunday, and a detailed plan of mitigation.
- Noise level increase limits above ANL are set for protected use receptors for locations at the property line, at the closest exterior point of the structure, or inside the structure. These limits are: 5 decibels over ANL from 6:00 am to 7:00 pm, Monday through Saturday; 3 decibels over ANL 7:00 pm to 6:00 Monday through Saturday night; and 10 decibels over ANL for fracturing operations during the day only.

- Adjustments to the noise standards may be permitted based on a cumulative one hour basis at the following increments: 10 dBA for 5 cumulative minutes for one hour; 15 dBA for one minute per hour; and 20 dBA for less than one minute per hour.
- The site activities may not create a noise at the protected use property line, closest exterior point, or inside structure, that creates pure tones where 1/3 octave band sound-pressure level in the band with the tone exceeds the arithmetic average of the sound-pressure levels of 2 contiguous 1/3 octave bands by 5 dB for center frequencies of 500 Hertz and above, and by 8 dB for center frequencies between 160 and 400 Hertz, and by 15 dB for center frequencies less than or equal to 125 Hertz; or
- The site activities may not create low-frequency outdoor noise levels that exceed 16 Hz octave band as 65 dB, 32 Hz octave band at 65 dB, and the 64 Hz octave band at 65 dB.
- The maximum permitted sound levels at compressor station by zone level are: 75 dBA/day and 65 dBA/night for the Industrial zone; 65 dBA/day and 55 dBA/night for the commercial zone; 55 dBA/day and 50 dBA/night for the residential zone; and the application of the lower noise standard at the boundary between zones.
- The allowed noise level at compressor stations may be raised if it can be shown that the actual ambient level is higher than the allowed level.
- Noise levels must be monitored continuously at all gas wells located within 600 feet of a protected use.
- If a complaint is received from any protected use, the operator is required to begin 72 hour continuous monitoring of exterior noise within 24 hours of the complaint.
- Noise mitigation can consist of acoustical blankets, sound walls, mufflers or other alternative methods approved by the City gas inspector and fire department.
- If an operator is in compliance with the noise management plan and a violation still occurs, the operator will be given 24 hours from the notice of non-compliance to correct the violation before a citation is issued. Additional extensions may be granted if the source of the violation can not be identified.

2.8.2 Mitigation of Light Impacts

Colorado, Louisiana and the City of Fort Worth were the only jurisdictions that addressed lighting impacts. The regulation for each requires that the oil and gas industry direct site lighting downward and internally to the extent practicable. Louisiana and the City of Fort Worth targeted the minimization of glare on public roads and adjacent buildings located within 300 feet of the well. Colorado specifies the minimization of glare for roads and building units within 700 feet. They all recognize that safety of the well site workers is an important consideration.

2.9 Setbacks

All of the states have setback requirements, but few of those surveyed, with the exception of the City of Fort Worth and, to a lesser extent, Louisiana, targeted setbacks to unconventional gas drilling. The following discussion of setbacks from each surveyed jurisdiction is focused toward setbacks from water resources and private dwellings.

2.9.1 Arkansas

Arkansas defines setbacks for production lease property lines as measured from the vertical projection of the production zone to the surface. The environmental setbacks are specified as measured from storage tanks. The setback requirements are as follows:

- No tank can be closer than 200 feet from an occupied habitable dwelling unless waived by the owner. If acceptable to the owner, then no tank will be less than 100 feet from the dwelling and the tank bottoms must be enclosed with a fence.
- No tank can be within 300 feet for a school, hospital or public use building.
- No tank can be closer than 300 feet of a stream or river designated as a Extraordinary Resource Water, Natural and Scenic Waterway, or Ecologically sensitive water body.
- No tank can be closer than 200 feet from any surface water body or wetland as designated by the blue line boundary on a 7.5 minute quadrangle map.

2.9.2 Colorado

Colorado defines the setback as measured from the surface operation; which includes drilling, completion, production and storage. The buffer does not include anything in the subsurface and does not apply to areas that do not drain to classified water supply segments.

Colorado has established three buffer zones that are classified as:

- Internal Buffer: 0 to 300 feet
- Intermediate Buffer: 301 to 500 feet
- External Buffer: 501 to 2640 feet

The state requires that notification be given to potentially impacted public water systems when operations lie within an Internal or Intermediate Buffer zone that is within 15 miles upstream from the public water system.

2.9.3 Louisiana

The setback distances for environmental purposes are taken as a straight line from the wellbore. The following setbacks are required by Louisiana:

- No well drilled for gas can be closer than 330 feet to any property line.
- Wells must not be within 500 feet of commercial or residential structures.
- No well can be drilled with 500 feet of a residence, religious institution, public park or public building. The distance is measured from the wellbore to the exterior wall of the building or the boundary of the park.
- The setback distance can be reduced to 200 feet if the owner of the building consents or the owner is a party to the mineral lease. This reduction is subject to agreement in the lease.
- The setback distance must be a minimum of 1,000 feet from the shoulder of an interstate highway crossing at a major waterway.

- An operator who receives a permit to drill within 1,000 feet of an interstate highway must furnish a copy of the approval permit and certified location plat to the appropriate state authorities, local authorities, and emergency responders.

2.9.4 New Mexico

The setback requirements obtained for New Mexico were taken as a straight line from any pit, which include fluid storage, drilling circulation and waste disposal pits. No other setback requirements have been identified at the time of this report. The pit setbacks are as follows:

- Pits must be greater than 300 feet from continuously flowing water courses or greater than 200 feet from any other significant water course, lake bed, sinkhole, or playa lake.
- Temporary pits must be more than 300 feet from a permanent residence, school, hospital, church or institution.
- Pits must be more than 500 feet from private, domestic, fresh water wells or springs used by less than 5 households for domestic or stock purposes, and greater than 1000 feet from any other fresh water well or spring.
- No pit can be within a defined municipal fresh water well field.
- Pits must be more than 500 feet from wetlands.
- Pits are not to be placed in an overlying or subsurface mine unless it can be proven that the pit's construction and use will not compromise subsurface integrity.
- Pits must not be placed in an unstable area.
- Pits can not be placed within a 100-year floodplain.

2.9.5 Ohio

Ohio defines setback distances as measured from the wellhead. The setback requirements are:

- The well must be at least 100 feet from a private dwelling.
- Private water supply wells must be a minimum of 200 feet from gas wells.

- The proposed wellhead location in urban areas must be 75 feet from the property line if the property owner is not in the subject tract or drilling unit, unless the adjacent property owner approves the drilling location.
- The wellhead should be located at least 50 feet from railroad tracks and from the traveled portion of streets, highways and roads.
- There are no established setback requirements from streams, domestic supply springs and surface water bodies; however, the regulatory agency may require setbacks to protect health, safety and natural resources. The regulations also state that the operators conduct the oil and gas development activities in a manner that will not contaminate or pollute the land surface, surface water or ground water.

2.9.6 Pennsylvania

The setback reference point for PA is defined as all disturbed areas of the "well site", which includes well pad limits and access roads. The setbacks are as follows:

- A minimum setback of 200 feet from private dwelling and water supplies (spring and wells).
- A setback of 100 feet is required for surface water bodies and wetlands.

2.9.7 City of Fort Worth

The City of Fort Worth has a two-tiered setback reference point to accommodate single wells or multi-well pads. The setback is a straight line from the wellbore center at the ground surface for single wells (gas well reference point), and a straight line from the closest point on the perimeter of the well pad for multi-well sites (gas wells reference point), unless otherwise noted. The setback requirements are as follows:

- A minimum distance of 200 feet must be maintained between any existing fresh water well and the closest gas well bore unless the well owner has signed a waiver.

- A distance of 75 feet must be maintained between the gas well(s) reference point and public streets, roads, right-of-ways, or future streets.
- A distance of 600 feet is required between the gas well(s) reference point and the closest exterior point of any protected use structure, except schools. The measurement is from the well reference point to the property boundary for schools. Other protected use structures include residences, religious institutions, hospital buildings, and public parks. The setback distance may be decreased to a minimum of 300 feet if a waiver has been granted by owners or the City Council.
- Public buildings must be a minimum of 300 feet from the gas well(s) reference point.
- Habitable structures (structures not currently inhabited) must be 200 feet from the gas well(s) reference point.
- The gas well(s) reference point must be 100 feet from buildings that are accessory to the gas development operation, but are not necessary for the operation.
- The gas well(s) reference point also cannot be closer than 75 feet to a property line.

2.9.8 Wyoming

The Wyoming regulations state that pits, wellheads, pumping units, tanks and treatment systems must be located no closer than 350 feet from water supplies, residences, schools, hospitals, or other structures where people are known to congregate. The regulation agency can establish greater distances for good reasons and also can grant exceptions.

2.9.9 Discussion of Setbacks

The setback requirements for the City of Fort Worth may be the best analogue for unconventional shale gas requirements in densely populated areas of NYS. Less stringent setback requirements may be appropriate in rural and less densely populated portions of New York depending on distances to the nearest receptors. The extended duration, large drill rigs and great number of trucks and equipment entering, operating in, and leaving each multi-well drill pad will create noise, light and visual impacts to the neighbors. The setbacks for the City of Fort Worth accommodate these impacts with a setback of 600 feet between protected use structures (residences, churches, schools, hospitals and public parks) and the limits of a multi-well pad. The rest of the Fort Worth setbacks also appear reasonable and accommodate other sensitive sites such as wells, springs, wetlands and public thoroughfares. Most of these setbacks are subject to waiver by agreement of the affected parties and the regulating agency.

2.10 Multi-Well Pad Reclamation Practices

The State of Pennsylvania is the only jurisdiction surveyed that provides any requirements with respect to multi-well pad reclamation practices. All other states apparently treat pad reclamation the same as conventional single well pads. The PA regulations simply state that the operator shall design, implement and maintain best management practices (BMPs) in accordance with an erosion and sediment control plan that is prepared following specifications provided in the regulations. This plan is to be implemented during and after soil disturbing activities that encompass the site and access roads.

Additional information was gleaned from the inspection of pads in PA that involved active drilling sites: multiple wells undergoing fracturing; active post-frac treatment, containerization and removal of flowback; gas production; and gas compression. In general, the initial pad sizes are 3 to 5 acres. The larger sizes are necessary to accommodate pits and tanks for up to eight horizontal wells per pad. Most pads will be reduced in size after the wells are completed and the site is transformed to the production phase. The typical well pad is expected to be reduced to approximately 1.5 to 2 acres, depending on the number of wells on the pad, and remain at the reduced dimension through the productive life of the wells. This smaller size is possible due to the ability to place up to 8 wells approximately 15 to 20 feet apart within an area of approximate dimension of 250 by 360 feet.

Well site reclamation commences soon after each phase is completed and the site is prepared for subsequent phases. The initial reclamation includes closure of pits that are not needed after drilling has been completed. These pits are closed and the drilling fluids are disposed or retained as described in Section 2.2. The well pad size reduction and the timing of reclamation are expected to be variable and dependent on the operator’s needs and schedule.

2.11 Naturally Occurring Radioactive Materials (NORM)

None of the states whose regulations were reviewed by Alpha (AR, CO, LA, NM, OH, PA, TX, WV, WY) have formally assessed the occurrence of naturally occurring radioactive materials (NORM) from longer duration drilling operations at multi-well sites and larger accumulations of shale cuttings from horizontal drilling. The oil and gas (O&G) industry and federal and state regulatory agencies in all O&G producing states are well aware of the NORM issue (now Technologically Enhanced NORM (TENORM); see USEPA, 2009A) in produced waters and in exploration and production (E&P) equipment. Various government agencies, laboratories and industry organizations have made efforts to further define the extent of O&G NORM and institute various levels of regulation and operational guidance.

By definition, NORM are not subject to regulation under the federal Atomic Energy Act (AEA) or the Low Level Radioactive Waste Policy Act (LLRWPA), and NORM are specifically exempted from Resource Conservation and Recovery Act (RCRA) regulations. At present, there is a considerable range of direct regulatory oversight of O&G NORM at the state level (Souders, 2005) and only indirect regulation through environmental impacts on drinking water sources (Safe Drinking Water Act (SDWA)), and cleanup of abandoned hazardous waste sites (CERCLA, and National Contingency Plan (NCP)). Because NORM are not restricted to the O&G industry, state regulatory authority varies from health departments, to environmental protection/conservation agencies, to O&G bureaus/divisions. Louisiana, New Mexico and Texas currently are the three states with the most comprehensive O&G NORM regulatory programs. These programs include permitting/licensing requirements, occupational and public exposure limits, exclusion levels, procedures for handling NORM, monitoring and reporting requirements, and specific E&P NORM disposal regulations. The effectiveness of these relatively recent programs regarding human and environmental health protection has not been evaluated because the programs have been implemented only within the last decade.

2.11.1 NORM in the U.S.A.

Detection of elevated levels (multiple times background) of NORM in O&G drill sites in the North Sea and U.S. Gulf Coast and mid-continent areas in the 1980s led to concerns about health impacts on drill site workers and the general public where exploration and production equipment and wastes were disposed or recycled. The U.S. Environmental Protection Agency (USEPA) measured values of radioactivity ranging from 9,000 picocuries per liter (pCi/l) for produced water to >100,000 pCi/l for pipe and tank scale (USEPA, 2009B). The annual general public and occupational radiation dose limits vary above estimated background levels of 300-400 millirem (mrem) (Health Physics Society, 2009), depending on the agency of origin. The annual dose limits range from several tens to 5,000 mrem among the Nuclear Regulatory Commission (NRC), U.S. Department of Energy (USDOE), and USEPA (Health Physics Society, 2009). Additional components to the NORM issue are: 1) NORM are commonly measured in concentration units, either pCi/l or pCi/g (picocuries per gram), while health standards for all types of ionizing radiation are provided in dose equivalent units (mrem/yr) for which there is no simple or universally accepted equivalence of these units; and 2) most states have not yet formally classified O&G drill rig personnel as occupational radiation workers.

Oil &Gas NORM occur in both liquid (produced waters), solid (pipe scale, cuttings, tank and pit sludges), and gaseous states (produced gas). The largest volume of NORM is in produced waters. Radionuclides of concern and the respective decay characteristics are summarized in Table 2.12. Field surveys to date have found that the most useful predictive factor for NORM levels of concern is the chloride concentration of the produced water (Cl^{-} > 20,000 mg/l correlates with Ra activity > 3.7 becquerel per liter (Bq/l) or 100 pCi/l); (McBurney, 2008). Radium is the most significant radionuclide contributing to O&G NORM and is fairly soluble in saline water. Radon gas, the main human health concern from NORM, is produced by the decay of Radium-226, which occurs in the Uranium-238 decay chain. Uranium and thorium, which are naturally occurring parent materials for radium, are contained in mineral phases in the reservoir rock cuttings, but have very low solubility. The very low concentrations and very long half-lives are such that uranium and thorium pose little potential health threat.

In addition to E&P worker protection from NORM exposure, the disposal of NORM-contaminated E&P wastes is a component of the O&G NORM issue. This has attracted considerable attention because of the large volumes of produced waters (>10^9 bbl/yr; API estimate) and the high costs and regulatory burden of the main disposal options, which are underground injection in Class II Underground Injection and Control (UIC) wells, and offsite treatment. The Environmental Sciences Division of Argonne National Laboratory has addressed E&P NORM disposal options in detail and maintains a Drilling Waste Management Information System website (Argonne National Laboratory, 2009) that links to regulatory agencies in all O&G producing states, as well as providing detailed technical information.

2.11.2 State and Federal Responses to O&G NORM

Discovery of elevated concentrations of NORM levels led to a series of state and private investigations of the issue. State responses to the potential of elevated O&G NORM ranged from no action (barring self-reported problems), to decisions for further study, to implementation of new formal regulations and guidance documents. To date, no state has assessed the occurrence of NORM from longer duration drilling operations at multi-well sites and larger accumulations of shale cuttings from horizontal drilling. NORM is not subject to direct federal regulation (except its transport) under either the AEA or LLRWPA, and E&P wastes are specifically exempt from regulation under Subtitles D and C of RCRA (LA Office of Conservation, 2009); however, NORM is regulated indirectly at the federal level through potential environmental impacts to drinking water (SDWA) and cleanup of abandoned hazardous waste sites (CERCLA and NCP).

The State of Louisiana was the first state to implement an O&G NORM regulatory program, and their program remains one of the most comprehensive to date. The Louisiana Department of Environmental Quality (LADEQ) has implemented a program that includes the identification, use, possession, transport, storage, transfer, decontamination, and disposal of O&G NORM to address the protection of human health and the environment. The primary NORM regulations are found in LAC 33:XV, Chapter 14: "Regulation and Licensing of Naturally Occurring Radioactive Material (NORM)". A Memorandum of Understanding (MOU) between the

LADEQ and the Louisiana Department of Natural Resources (LDNR) addresses the responsibilities of the two agencies with respect to E&P wastes contaminated with NORM.

Section 1403 of the Louisiana Administrative Code defines NORM as "any nuclide that is radioactive in its natural physical state (i.e. not man-made), but not including source, by-product, or special nuclear material." This broad definition includes much more than just E&P NORM. The action levels provided in Section 1404 for E&P equipment and land contaminated by NORM are provided in the following list. The statute does not apply to levels below those listed.

- NORM, NORM Waste, and NORM contaminated material $\geq$ 5pCi/g above background of Ra-226 or Ra-228, or > 150 pCi/g of any other NORM nuclide.
- Equipment $\geq$ 50 microroentgens per hour (µR/hr) at any accessible point
- Land averaged over any 100 square meters with no single noncomposited sample to exceed 60 pCi/g of soil
    - > 5 pCi/g above background of Ra-226 or Ra-228, averaged over the first 15 cm, and 15 pCi/g above background over each subsequent 15 cm; or
    - > 30 pCi/g of Ra-226 or Ra-228, averaged over 15 cm depth increments, provided the total effective dose equivalent from the contaminated land does not exceed 0.1 rem/year.

Louisiana follows the USEPA exemption of O&G produced waters as hazardous waste under RCRA, but understands that these fluids may contain substances harmful to human health and the environment (e.g. NORM). The Injection and Mining Division of the Louisiana Office of Conservation (LOC) regulates the subsurface injection of produced waters in compliance with the federal UIC program established under the SDWA. The E&P Waste Management Section of the Environmental Division of the LOC regulates commercial E&P waste storage, treatment and disposal facilities and coordinates all UIC enforcement actions brought against Class II injection wells.

Section 1412 covers the treatment, transfer, and disposal of NORM wastes in accordance with the following:

- by transfer to a land disposal facility licensed by Louisiana Department of Environmental Quality (LDEQ), NRC, and agreement state, or a licensing state;
- by alternate methods authorized by the LADEQ in writing upon application or upon LADEQ's initiative;
- For E&P waste containing NORM at concentrations not exceeding 30pCi/g of Ra-226 or Ra-228, by transfer to an E&P waste commercial facility regulated by the DNR for treatment, if certain conditions are met by the facility; and
- For E&P waste containing concentrations of NORM in excess of the limits in Subsection 1404-a.1, but not exceeding 200 pCi/g Ra-226 or Ra-228 and daughter products, by treatment at E&P waste commercial facilities specifically licensed by LADEQ for such purposes.

Chapter 14 of LAC 33:XV also presents specifics of NORM surveys (Section 1407); worker protection (Section 1411); licensing/permitting (Section 1408); removal/remediation (see licensing and permitting); storage (Sections 1414 through 1416); transfer for continued use; and release of sites, materials and equipment for unrestricted use (Section 1417).

The State of Texas has also developed comprehensive NORM regulatory programs. NORM is regulated in Texas under the Texas Radiation Control Act by three separate agencies: The Texas Department of State Health Services (TDSHS); The Railroad Commission of Texas (TXRRC); and the Texas Commission on Environmental Quality (TCEQ). The Radiation Control Program within the Radiation Safety Licensing Branch of TDSHS regulates the use, treatment, and storage of NORM under 25 Texas Administrative Code §289.259 "Licensing of Naturally Occurring Radioactive Material." The TXRRC regulates the disposal of O&G NORM under 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632; "Disposal of Oil and Gas NORM Waste". The TCEQ has jurisdiction over the disposal of other NORM wastes. Performance of NORM decontamination, and disposal by the owner through on-site land farming and/or injection well disposal is under the TXRRC's purview. Currently, TDSHS O&G NORM waste is defined as anything that constitutes, is contained in, or has contaminated O&G waste and exceeds the TDSHS exemption level of 50 μR/hr or has a concentration of 50 pCi/g. This includes E&P equipment, and scale deposits in equipment, but not natural gas or gas products or produced waters, which are exempt. NORM contaminated equipment must be identified using specified radiation survey equipment compliant with TDSHS regulations. Persons who are involved with the disposal of O&G NORM must comply with provisions of the TDSHS regulation 25TAC §289.202 including:

- Radiation protection program;
- Occupations dose control;
- Surveys and monitoring;
- Signs and labels; and
- Record keeping.

O&G NORM disposal methods that are specifically prohibited by Chapter 4, Subtitle F, §4.611 include:

- Discharge to surface or groundwater;
- Spreading on public roads; and
- Burial or land farming except on lease where generated by rule.

All other disposal methods require permits. The Technical Permitting Section of the Oil and Gas Division of the TXRRC issues permits for injection well disposal of produced waters which contain dissolved NORM. The permits are in full compliance with the UIC Class II well regulations as defined under the SDWA.

NORM in the Marcellus Shale in NY

A 1999 study by NYSDEC reported no significant levels of radioactivity in oil and gas equipment or wastes, and that "The concentrations of NORM found on oil and gas production and equipment and wastes pose no threat to the public health and the environment". This study did not involve the sampling and analysis of cuttings, brine, flowback, waste or equipment from wells targeting the Marcellus Shale.

2.12 Stormwater Runoff

Most of the reviewed states have stormwater runoff regulations or best management practices for oil and gas well drilling and development. Not all of these states have adjusted their rules and regulations to accommodate the larger pad sizes and duration of site activity. Regardless, most of the existing practices are adaptable and are discussed herein for each state as possible sources of relevant information.

2.12.1 Arkansas

Arkansas has a tiered system that takes into consideration the size of the site. The following are the primary permits that are required:

- The operator must prepare a stormwater erosion and sediment control plan (SWESCP) to ensure implementation of controls for the well site and access roads.
- All construction sites must submit a form to allow stormwater discharge from the site.
- Operators at sites with more than 5 acres of disturbed area must file a Notice of Intent (NOI) along with a form to allow the discharge, and the operator must complete a Stormwater Pollution Prevention Plan (SWPPP). Any single lot that is less than 5 acres, but is part of a plan of greater than 5 acres, may be permitted under automatic coverage.

2.12.2 Colorado

The Colorado stormwater control regulations were promulgated on April 1, 2009 in part to address the larger unconventional gas well site. These regulations include an exemption provision for sites less than one acre provided other criteria have been met related to slope, site erodibility and distance to a perennial stream or classified water source. The stormwater regulations for non-exempt sites, which include the large multi-well pad site, require the implementation of Best Management Practices (BMPs) throughout the duration of site construction activities followed by a post-construction stormwater program that remains in force until the site is abandoned and fully reclaimed.

The BMPs, which are part of the construction stormwater permit, must include good engineering practices that include, but are not necessarily limited to:

- Covering potential contaminant sources and diverting stormwater to minimize contact with precipitation and waste sources that have a potential to result pollution discharges,
- Implementation of material handling and spill prevention procedures to minimize the discharge or release of pollutants,
- Application of erosion controls to minimize erosion from unpaved areas,
- Implementation of self inspection, maintenance and good housekeeping procedures to identify and mitigate potential or developing failures in the erosion control system,
- Maintenance of spill control procedures and equipment that will be needed in the event of a spill, and
- Application of controls and maintenance procedures to control the movement of sediment resulting from vehicle traffic and access road degradation.

Colorado mandates that the operators develop the Post-Construction Stormwater Program that will be in place and operational when the Colorado Stormwater permit expires. The BMPs for the post-construction phase cover the period when the wells are in production. These BMPs should include elements that control potential pollutants associated with:

- Transport and handling of chemicals and material,
- Vehicle and equipment fueling,
- Outdoor storage of materials and chemicals,
- Storage of produced water and drilling fluids,
- Outdoor processing and equipment,
- Dust generation,
- Sediment movement from vehicle traffic and erosion of unpaved areas,
- Water disposal,

- Leaks and spills, and
- Ground disturbances from onsite activities.

Colorado specifies that the Post-Construction Stormwater Program be developed, supervised, documented and maintained by a qualified person and that other employees and on-site contractors be educated on the implementation and maintenance of the BMPs. Facility specific maps, installation specifications, and implementation criteria also must be included in the program when general operating procedures are not adequate to clearly describe the implementation and operation of BMPs.

2.12.3 Louisiana

Oil and gas exploration, production, processing, treatment and transmission activities are exempt from stormwater runoff regulation in Louisiana. The regulations define those activities for which the EPA shall not require a National Pollutant Discharge Elimination Permit (NPDES). In general, the Louisiana stormwater provision recommends that surface water runoff be diverted around waste containing pits and that erosion be reduced by directing runoff in a manner that simulates natural flow patterns, quantity, quality and rates. Discharge from pits also is allowed if the operator files a Notice of Intent (NOI) and the pit fluid is not contaminated as defined by state regulations. This discharge can occur within 14 days after submission of the NOI. The operator must monitor the discharge and maintain records of all discharge for 5 years.

2.12.4 New Mexico

New Mexico has a BMP document and a BMP guide that is use for stormwater control at oil and gas sites. The following are the key elements in these BMPs:

- All drums, saddle tanks, sacks or buckets, which contain material other than fresh water or substances that are gases at atmospheric temperature, must be stored on an impermeable pad with curb type containment;

- All above ground tanks that contain fluid other than fresh water must be contained in an impermeable, bermed enclosure that has sufficient freeboard to contain a volume of one-third more than the total volume of the largest tank or all interconnected tanks;
- All below grade tanks, sumps and pits must have secondary containment and leak detection;
- Any facility area where leaks and spills can reach the ground surface must be paved and curbed, or have some type of spill collection;
- Proposed methods for preventing contaminants from reaching the ground surface must be stated in the BMP;
- All spills must be reported and remediated;
- Any water contaminants must be contained within the facility boundary and a description of methods to achieve this must be in the BMP;
- The operator must collect stormwater and use it in the processes;
- All roads must follow standards in the Bureau of Land Management "Gold Book" to reduce soil erosion;
- Any roads used exclusively for construction purposes must be adequately closed to all vehicular travel and rehabilitated after completion of construction;
- If produced water meets the New Mexico Water Quality Control Commission surface water standards, consider using it for irrigation of reclaimed areas until vegetation is established;
- Construct road and pipeline crossings perpendicular to wetland/riparian areas, including ephemeral channels. Minimize the duration of construction and concentrate activity during dry conditions. Reshape disturbed channels to the approximate original configuration;
- Divert washes around well pads;
- Employ silt curtains, dikes, coffer dams, or other suitable erosion control measures. Replace lost riparian woody vegetation at a ratio of 2 acres for each acre lost, and 10 saplings for each mature tree lost;
- Install culverts of sufficient size (minimum 18 inches) where drainages cross access roads;

- Sidehill cuts of more than 3 feet vertical are not permitted. Areas requiring deeper cuts will be terraced so none are greater than 3 feet;
- Maintain a vegetated buffer zone along watercourses, including ephemeral arroyos, sufficient to minimize headcutting and sediment delivery;
- Mulch disturbed areas;
- Properly align roads, on moderate grades with a side slope, and ensure adequate drainage;
- Mud and blow pits will be constructed to prevent leaks, breaks, or discharges of liquids or produced solids;
- Re-contour and re-vegetate unused disturbed ground around well pads and above buried pipelines soon after completion of the well;
- Clearing, grading, and other disturbance of soil and vegetation is limited to the minimum area required for construction;
- Disturbed areas will be reseeded following specifications using designated seed mixtures within one year of final construction;
- Water quality in drilling areas will be protected by the use of closed-loop drilling systems (i.e. pitless drilling); and
- Water quality in drilling areas must be protected by the use of water-based drilling fluids.

2.12.5 Ohio

Ohio requires that the operator implement BMPs in urbanized areas. This requirement appears to apply to all oil and gas development projects. The rule requires that the operator follow the BMPs provided in the oil and gas site construction manual prepared by the regulatory agency or develop their own if the operator can demonstrate that the alternate methods are equally effective.

2.12.6 Pennsylvania

Pennsylvania is one of the states that specifically address stormwater control for the larger multi-well pads. The state has two types of stormwater BMPs for sites greater than one acre. These

BMPs include unstructured and structured BMPs. The unstructured BMPs are general guidance statements or recommendations to protect sensitive or special resources, to minimize potential erosion by concentrating activities and reducing disturbed area, to promote infiltration by reducing impervious cover, to minimize concentrated flow, and to implement source control. The structured BMPs provide specific approaches for sediment erosion and runoff control. These structural controls include:

- Runoff volume reduction by slowing flow rates and inducing infiltrations by the use of pervious pavements, infiltration basins and trenches, subsurface infiltration beds, vegetation, dry wells, seepage pits, infiltration berms, and retentive grading;
- Runoff volume and flow rate reduction by the use of vegetation and capturing the runoff for reuse;
- Runoff rate and quality control by constructing wetlands, wet ponds, retention basins, water quality filters and hydrodynamic devices; and
- Controlling erosion and runoff by restoring disturbed areas and decentralizing flow with level spreaders and detention basins.

2.12.7 West Virginia

The West Virginia stormwater regulations require a General Water Pollution Control Permit, which precludes purging of water and runoff into surface water. The regulation states that surface water must be diverted away from pits, and water quality controls needed to be provided to protect surface water and land application sites. Produced water discharges must not include floating solids, visible foam or free oil.

2.12.8 Wyoming

Wyoming stormwater regulations allow the filing of a general permit. These permits typically require a notice of intent for each site; however, oil and gas exploration and development sites are exempt unless certain water quality and quantity thresholds have been exceeded or a violation has occurred. An exemption is also allowable for sites less than 5 acres if specified technical criteria are met.

2.12.9 Discussion of Stormwater

The BMP approach appears to be effective and is the adopted approach in CO, NM and PA. The NM BMPs do not appear to be suitable for NY, particularly with regard to the placement of impervious and curbed containment controls beneath all tanks that contain fluids other than fresh water because the large pad sizes and large number of tanks utilized in frac jobs for horizontal gas wells would necessitate extensive areas of pavement. Paving large areas has the potential for greater runoff rates and the need for more extensive sediment and flow control structures if employed in the humid northeastern climate.

Pennsylvania is probably the most suitable model for NY. Pennsylvania promotes reducing high runoff rates and associated sediment load by inducing infiltration. The operators in PA place a berm around the drilling pad and underlay the pad with a filter fabric that allows the infiltration of precipitation. The operators control runoff impacts from major storms along access roads by placing a temporary berm across the road during the storm to complete a full site perimeter berm. This prevents rapid discharge down erodible access roads if sloping downhill from the site.

Authorization to discharge stormwater will be required under the NYSDEC SPEDES General Permit, which also requires preparation of a Stormwater Pollution Prevention Plan. The 1992 GEIS states that erosion control measures are necessary if an access road is subject to erosion and in conjunction with a stream disturbance permit, if necessary. An erosion and sediment control program is required by the 1992 GEIS if drilling occurs within the watershed of a drinking water reservoir. The DRBC and SRBC also require controls within the respective river basins.

2.13 Recommended Information to Accompany Drilling Applications

Most states that are experienced in permitting oil and gas wells use similar drilling applications, which are submitted to the state agency that regulates the permitting of new wells or changes to existing wells. These applications typically include:

- owner, operator, and driller information;
- planned operation;
- proposed start date
- well name
- well type and well bore type;
- well location and field/pool name that often include a plat;
- well spacing and assigned acreage;
- proposed formation and target interval information;
- drilling fluid information; and
- casing, cement, and well completion specifications.

Oil and gas well permitting applications or attachments to the applications usually include environmental assessment information. This information typically includes:

- project dimensions, including access roads and the well site;
- existing site vegetation, types and coverages;
- current and previous land uses and disturbances;
- neighboring land uses;
- other environmental resources on or near the project site, which include:
    - water supplies – aquifers; public and private wells and springs; reservoirs;
    - surface water bodies;
    - wetlands;
    - agricultural districts;
    - flood plain or buffer zone;
    - coastal management area;

    - threatened or endangered flora and fauna; and
    - visual resources.
- cultural resources;
- basic erosion and reclamation plans;
- access road siting;
- waste storage and disposal, including drilling and produced fluids, drill cuttings, and pit liners; and
- other permit requirements.

Fracture stimulation of shale formations, including the Marcellus shale, and the drilling of multiple wells on a well pad are associated with additional potential environmental impacts caused by the greater volumes of fluid used and produced, and the longer duration and larger physical size of the operations. More information about proposed operations and possible mitigation measures is helpful in minimizing or eliminating potential environmental impacts. The following additional information would be useful in a drilling application to evaluate potential impacts for each well pad used for horizontal wells with high volume hydrofracturing:

- nearby landowner notification, including proposed well type, location, and water supply;
- pre-operation sampling plan for water supply wells and springs within 1000 horizontal feet of the nearest point of the multi-well pad;
- well pad design plat, including disturbed areas;
- pit design drawings with a pit application that includes construction specifications and leak detection system plans;
- pit closure plan;
- fracture fluid (and flow-back) recycling, reuse, and disposal plan;
- produced water use and disposal plan;
- fluid storage details;
- fracture fluid and proppant composition and Material Safety Data Sheets;
- equipment list and noise assessment, lighting plan, and proposed energy sources if there are concerns not addressed by the 1992 GEIS or the SGEIS

- emergency response district;
- proposed public safety precautions;
- well location plat should cover a sufficient area, and be of appropriate scale to show surface water bodies, wetlands, drinking water supplies, any applicable setbacks, and protected use properties (residences, religious institutions, hospitals, schools, and public parks) within at least 1000 feet of the well or multi-well pad;
- variance requests –setbacks, when necessary;
- water management plan: water source list, expected quantities, source type, drainage basin; low flow analysis, etc;

The report appendix includes selected sample forms that experienced shale gas producing states use to collect such information.

2.14 Recommendations for Minimizing Potential Liquid Chemical Spills

In addition to the information recommended in Section 2.13 for assessing potential environmental conditions, this section provides specific recommendations to minimize the potential for liquid chemical spills or leaks to impact surface and ground water resources. These recommendations would apply to liquid chemicals and fuels present onsite, if there are concerns that are not elsewhere addressed by the 1992 GEIS or the SGEIS.

When such a concern exists, the applicant should identify the anticipated maximum number, type, and volume of non-stationary tanks containing petroleum fuel or liquid frac-fluid additives to be simultaneously present onsite so that the NYSDEC can evaluate whether those containers could reasonably be anticipated to discharge to surface or ground water, if a spill occurred. The criteria for this evaluation may include considering factors such as the nature and classification of the liquid, qualitative soil permeability, relative topographic position, engineered/designed or containment controls, or other physical factors specific to the application.

- It is recommended that setbacks from the edge of the well pad be required if a spill could reasonably reach surface or ground water. The setback should be a minimum of

150 feet from a perennial or intermittent stream, private or public well, wetland, storm drain, lake, or pond.

- Additional control measures may be required to provide secondary containment when drilling occurs within areas designated as primary or principle aquifers, and when otherwise deemed necessary based on the NYSDEC's determination. The secondary containment should be sufficient to contain 110% of the single largest liquid chemical container within a common staging area.

The secondary containment requirement should be flexible to accommodate various scenarios, and could include, as deemed appropriate, one or a combination of the following; dikes, liners, pads, holding ponds, impoundments, curbs, ditches, sumps, receiving tanks, or other equipment capable of containing the substance. Soil that is used for secondary containment should be of such character that a spill onto the soil will be readily recoverable and will result in a minimal amount of soil contamination and infiltration.

3.0 WATER ISSUES RELATED TO HIGH-VOLUME HYDRAULIC FRACTURING

This section provides an analysis of a variety of issues related to the potential impacts of horizontal drilling and high volume hydrofracturing on water resources. The following sections respond to the items identified in Section 1.1.2 (Task 2).

3.1 Water Classifications and Quality Standards

Alpha reviewed the ground water and surface water classifications and quality standards established by the US EPA, NYSDEC, DRBC SRBC, NYCDEP, and the Upper Delaware Council. The review revealed that the NYCDEP defers to the NYSDOH for water classifications and quality standards. The most recent New York City Drinking Water Quality Report can be found at http://www.nyc.gov/html/dep/pdf/wsstate08.pdf. Alpha's research also indicates that the SRBC and the Upper Delaware Council have not established independent classifications and quality standards; however, one of the roles of the SRBC is to recommend modifications to state water quality standards to improve consistency among the states. The Upper Delaware Council is a formal partnership of local, state, and federal governments and agencies created to manage the upper Delaware River. The Upper Delaware Council has not established surface water or ground water standards separate from existing state and federal standards. The relevant and applicable water quality standards and classifications include the following:

- 6NYCRR Part 703; Surface Water and Groundwater Quality Standards and Groundwater Effluent Limitations (http://www.dec.ny.gov/regs/4590.html)
- US EPA Drinking Water Contaminants (http://www.epa.gov/safewater/contaminants/index.html)
- 18CFR Part 410; DRBC Administrative Manual Part III Water Quality Regulations (http://www.state.nj.us/drbc/regs/WQRegs_071608.pdf)
- 10 NYCRR Part 5; Subpart 5-1 Public Water Systems (http://www.health.state.ny.us/environmental/water/drinking/part5/subpart5.htm)
- NYCDEP Drinking Water Supply and Quality Report (http://www.nyc.gov/html/dep/html/drinking_water/wsstate.shtml)

3.2 Previous Drilling in Aquifers, Watersheds, and Aquifer Recharge Areas

There are nearly 10,000 public water supply systems in New York State that serve approximately 21 million consumers, many of whom are serviced by more than one system (NYSDOH, 2009). A majority of these systems (approximately 8,460) rely on ground water aquifers. There also are potentially tens to hundreds of thousands of private water supply wells in the state.

Primary aquifers are highly productive aquifers that are used by public water supplies serving more than 1,000 people. Principal aquifers are those known to be highly productive aquifers or where the geology suggests abundant potential supply, but are not presently being heavily used for public water supply. The 21 primary and the many principal aquifers greater than one square mile in area within New York State (excluding Long Island) are shown on Figure 3-1. The remaining portion of the state is underlain by smaller aquifers or low-yielding ground water sources that typically are suitable only for small community and non-community public water systems or individual household supplies.

For oil and gas regulatory purposes, potable fresh water is defined as water containing less than 250 parts per million (ppm) of sodium chloride or 1,000 ppm total dissolved solids (TDS) and salt water is defined as containing more than 250 ppm sodium chloride or 1,000 ppm TDS (6NYCRR Part 550.3(at)). Ground water from sources below approximately 850 feet in New York typically is too saline for use as a potable water supply; however, there are isolated wells deeper than 850 feet that produce potable water and wells less than 850 feet that produce salt water. A depth of 850 feet to the base of potable water is a commonly used and practical generalization for the maximum depth of potable water; however, a variety of conditions affect water quality, and the maximum depth of potable water in an area should be determined based on the best available data.

The Marcellus and Utica shales dip southward from the respective outcrops of each member, and most of the extent of both shales are found at depths greater than 1,000 feet in New York (Sections 5.2 and 5.3). There are multiple alternating layers of shale, siltstone, limestone, and other sedimentary rocks overlying the Marcellus and Utica shales (Section 5.1). Shale is a natural, low permeability barrier to vertical movement of fluids and typically is considered a cap rock in petroleum reservoirs (Selley, 1998) and an aquitard to ground water aquifers (Freeze & Cherry, 1979). The varying layers of rocks of different physical characteristics provide a barrier to the propagation of induced hydraulic fractures from targeted zones to overlying rock units (Arthur et al, 2008). The vertical separation and low permeability provide a physical barrier between the gas producing zones and overlying aquifers.

Oil and gas drilling has been conducted in New York State since 1821, and an estimated 70,000 oil and gas wells have been since drilled in New York. The NYSDEC maintains records for 36,000 regulated wells, approximately 12,000 of which are active (NYSDEC, 2009). Horizontal wells have been drilled in New York since 1989 as a result of advances in drilling technology.

Hydraulic fracturing is a well-known method that has been used in both the oil and gas industry and the water well industry to enhance the permeability of bedrock by creating fractures in the rock. High-volume hydraulic fracturing is a relatively new procedure specifically associated with horizontal gas wells. The high volumes of fluids for this procedure are needed for hydrofracturing the greater depth/length of a horizontal well.

A tabulated summary of the regulated oil, gas, and other wells located within the boundaries of the primary and principal aquifers in the state is provided on Figure 3-1. There are 482 oil and gas wells located within the boundaries of 14 primary aquifers and 2,413 oil and gas wells located within the boundaries of principal aquifers. Another 1,510 storage, solution brine, injection, stratigraphic, geothermal, and other deep wells are located within the boundaries of the mapped aquifers. The remaining regulated oil and gas wells likely penetrate a horizon of potable freshwater that can be used by residents or communities as a drinking water source. These freshwater horizons include unconsolidated deposits and bedrock units.

Well drilling, construction, operation, plugging, decommissioning, and site restoration requirements are in place in New York to prevent the escape of oil, gas, brine, or water from one stratum to another. Municipal water wells are protected by the requirement of a full environmental assessment if a proposed oil or gas well is within 2,000 feet of a municipal well and a supplemental environmental impact statement if within 1,000 feet.

No documented instances of ground water contamination are recorded in the NYSDEC files from previous horizontal drilling or hydraulic fracturing projects in New York State (NYSDEC, 2009). No documented incidents of ground water contamination in public water supply systems were reported by the NYSDOH central office and Rochester district office (NYSDOH, 2009a; NYSDOH, 2009b). References have been made to some reports of private well contamination in Chautauqua County in the 1980s that may be attributed to oil and gas drilling (Chautauqua County Department of Health, 2009; NYSDOH, 2009a; NYSDOH, 2009b; Sierra Club, undated). The reported Chautauqua County incidents, which pre-date the current casing and cementing practices and fresh water aquifer supplementary permit conditions, could not be substantiated because pre-drilling water quality testing was not conducted and the incidents were not officially confirmed.

The current well drilling, construction, operation, plugging, decommissioning, and site restoration requirements appear to provide adequate safeguards for the protection of ground water resources, based on the absence of documented instances of ground water contamination since those requirements were implemented. The physical separation between the target drilling zones and the shallow potable fresh water sources provide additional protection of fresh water aquifers. Requirements for water supply well testing in the vicinity of gas drilling operations could provide data to evaluate background conditions and detection and remediation of water supply contamination, if issues are identified in the future. Recommendations for water supply testing are discussed in Section 2.13.

3.3 Potential for Invasive Species Transfer

An analysis was performed to evaluate whether operations associated with the withdrawal, transport, and use of water for horizontal well drilling and high volume hydraulic fracturing operations has the potential to transfer invasive species. Evaluation of upland or terrestrial invasive species transfer was beyond the scope of this review and was not performed. The presence of nonindigenous aquatic invasive species in New York State waters is recognized. Species of concern include, but are not necessarily limited to; zebra mussels, eurasian watermilfoil, alewife, water chestnut, fanwort, curly-leaf pondweed, round goby, white perch, didymo, and the spiny water flea. Nonindigenous invasive species are those that have been unintentionally (or intentionally, in some cases) introduced into habitats where the species previously were not native. These species typically thrive in the new habitat to the detriment of native species and eventually may become normalized (NYSDEC, 1993; NYSDEC, 2005; NYSDEC, 2009)

A concern exists that invasive species may be transported with the fresh water withdrawn for, but not used for drilling or hydrofracturing. Invasive species may potentially be transferred to a new area or watershed if unused water containing such species is later discharged at another location. Other potential mechanisms for potentially transferring invasive aquatic species may include trucks, hoses, pipelines and other equipment used for water withdrawal and transport.

There is considerable incentive for operators to use (and reuse) all the water withdrawn for drilling and hydrofracturing. Large quantities of water are used during the drilling and hydrofracturing of a horizontal well. The hydrofracturing process for a single horizontal well may require two to four million gallons of water (Fortuna, 2009, personal communication and Chesapeake, 2009, personal communication). Sixteen to thirty-two million gallons of fresh water may be used at a single multi-well pad to drill and hydrofracture up to eight wells. It is beneficial to the operators to implement water conservation and recycling practices because of the potential difficulties obtaining the large volumes of water needed for hydrofracturing. Most or all operators will recycle/reuse flowback water to reduce the need for fresh water.

It is possible that some unused fresh water may remain in an impoundment after drilling and hydrofracturing is completed. This is likely in circumstances where operators build large centralized impoundments to hold water for all drilling and hydrofracturing operations within a several mile radius. Unused water may be transported by truck or pipeline and discharged into tanks or impoundments for use at another drilling location. It also is possible that unused water could be transported and discharged at its point of origin with proper approval. Either of these options avoids the transfer of invasive species into a new habitat or watershed. Unused fresh water also could be transported to a wastewater treatment facility for processing, although this is considered unlikely given the anticipated demand for water in the drilling and hydrofracturing process. Flow-back water cannot be taken to a publicly owned treatment works within the Delaware River Basin without the approval of the DRBC. Standard treatment processes at waste water treatment plants, such as dissolved air flotation, have been shown to successfully remove biological particles and sediments that might harbor invasive species (Sansalone, et al., 2001); however, the safest method to avoid transfer of invasive species is to not transfer water from one water body to another.

Regulatory protections exist to mitigate the potential transfer of invasive species. Regulations and policies of SRBC and DRBC both address the transfer, reuse and discharge of water and have specific provisions to prevent transfer of invasive species. Table 3.1 is a matrix of SRBC and DRBC regulations pertaining to transfer of invasive species. The regulations are identified that specifically address the transport of invasive or nuisance aquatic species. Other regulations in table 3.1 do not specifically relate to invasive species, but the required actions and policies nonetheless may have the effect of reducing or eliminating their transport.

The control of invasive species in New York State falls within the purview of the NYSDEC, Division of Fish, Wildlife and Marine Resources. The NYSDEC is a co-lead agency (with the Department of Agriculture and Markets) for the New York State Invasive Species Task Force in a collaborative effort with many other state agencies to coordinate efforts focused on the issue of invasive species. Relevant guidance documents include "Nonindigenous Aquatic Species Comprehensive Management Plan", "Final Report of the New York State Invasive Species Task Force", and the "Comprehensive Wildlife Conservation Strategy (CWCS) Plan". The NYSDEC efforts to control invasive species focus on interagency coordination; public education; rapid response to new invasive species threats; and development, adoption, and implementation of mitigation measures.

The SRBC's policy is to discourage the diversion or transfer of water from the basin with the objective of conserving and protecting water resources (SRBC, 1998). Additionally, the SRBC specifically requires that "any unused (surplus) water shall not be discharged back to the waters of the basin without appropriate controls and treatment to prevent the spread of aquatic nuisance species" (SRBC, 2009).

The DRBC controls both exportation and importation of water from the Delaware River Basin. The DRBC's Rules of Practice and Procedure (DRBC, 2002) state that a project sponsor (e.g., operator) may not discharge to surface waters of the basin or otherwise undertake the project (gas well) until the sponsor has applied for, and received, approval from the commission. DRBC also prohibits discharge to the waters of the basin without prior approval. These actions and policies effectively control the use, withdrawal, discharge, and transfer to water from and into the basin and reduce the potential for transfer of invasive aquatic species.

The measures and protocols adopted by the SRBC and DRBC appear to be sufficient to address the potential for transfer of invasive species associated with water use for high-volume hydraulic fracturing. To the extent that operators seek to obtain, transport, use, and discharge water outside the jurisdictional boundaries of SRBC and DRBC, the NYSDEC may consider requiring equivalent mitigation measures for both large-scale basins and at smaller scales to avoid invasive species transfer.

3.4 Existing Water Withdrawal Application and Approval Processes

Alpha reviewed and evaluated the regulations and protocols of the DRBC, SRBC and the NYSDEC with respect to the sufficiency of the process for the application and approval of water withdrawal. Alpha specifically considered how the regulations and protocols address potential impacts of reduced stream flow, degradation of stream's designated best use, potential impacts to downstream wetlands, potential impacts to fish and wildlife, and potential aquifer depletion associated with shale gas development by high-volume hydraulic fracturing. Table 3.2 is a summary of relevant regulations for each of the agencies that pertain to these issues.

3.4.1 Potential Impacts of Reduced Stream Flow

Potential impacts of reduced stream flow associated with shale gas development by high-volume hydraulic fracturing in the Delaware River Basin are under the purview of the DRBC. The DRBC has the authority to regulate and manage surface and ground water quantity-related issues throughout the Delaware River Basin. The DRBC requires that all gas well development operators complete an application for water use that will be subject to commission review. The DRBC primarily uses the following regulations, procedures and programs to address potential impacts of reduced stream flow associated with a water taking:

- Allocation of water resources, including three major reservoirs for the New York City Water supply;
- Reservoir release targets to maintain minimum flows of surface water;
- Drought management including water restrictions on use, and prioritizing water use;
- Water conservation program;
- Passby flow requirements;
- Monitoring and reporting requirements;
- Aquifer testing protocol.

The DRBC regulations, procedures and programs are in place to protect streams from potential reductions in flow that could potentially arise from projects requiring large volumes of water within the Delaware River Basin.

The SRBC has the authority to regulate and manage surface and ground water withdrawals and consumptive use in the Susquehanna River Basin. The SRBC requires that all gas well development operators complete an application for water use that will be subject for commission review. The SRBC primarily uses the following regulations, procedures and programs to address potential impacts of reduced stream flow associated with a water taking:

- Consumptive use regulations;
- Mitigation measures;
- Conservation measures and water use alternatives
- Conservation releases
- Evaluation of safe yield (7-day, 10-year low flow);
- Passby requirements;
- Monitoring and reporting requirements;
- Aquifer testing protocol.

The goal of the SRBC, through its broad authority over water resources, extensive protocols and procedures, and monitoring programs, is to effectively limit the potential reductions in stream flow due to projects requiring large volumes of water.

The withdrawal of water in New York, in areas outside the Delaware and Susquehanna River basins, is largely under the purview of the NYSDEC. The NYSDEC primarily addresses the withdrawal of water and its potential impact on reduced stream flow in the flowing regulations:

- 6 NYCRR 605: Applications for Diversion or Use of Water for Purposes Other than Hydro-Electric Power Projects
- 6 NYCRR 675: Great Lakes Withdrawal Registration Regulations

The requirements of 6 NYCRR 605 pertain to surface water withdrawals and include an application that describes the project (location, plans, land ownership) and the proposed water withdrawal. The applicant is required to identify the source of water, anticipated daily diversion or use (in gallons) and the annual average maximum and minimum flow of the stream. The application, plans and specifications for the proposed project and fees are submitted for investigation, hearing and determination.

The purpose of 6 NYCRR 675 is to establish requirements for the registration of water withdrawals and reporting of water losses in the Great Lakes basin. Part 675 is applicable because a portion of the shales considered for potential high-volume fracturing are located within the Great Lakes Basin. Registration is required for non-agricultural purposes in excess of 100,000 gallons per day (30 day consecutive period). An application for withdrawal in the Great Lakes basin is required and addresses location and source of withdrawal, return flow, water usage description, annual and monthly volumes of withdrawal, water loss and a list of other regulatory (federal, state and local) requirements. There are also additional requirements for interbasin surface water diversions.

Requirements of the State Environmental Quality Review (SEQR) also may apply, when an application for a NYSDEC permit is made, per the provisions of the Uniform Procedures Act, if the proposed action does not fall within the existing GEIS or SGEIS. A completed

Environmental Assessment Form (EAF) accompanies the application as part of the SEQR requirements and generally begins the review process. Potential impacts to stream flow reduction would be addressed during the SEQR process.

The NYSDEC, through Parts 605 and 607, and the SEQR process, has significant regulatory control to limit the potential impacts of stream flow reduction due to water taking associated with high-volume hydraulic fracturing of shales.

3.4.2 Degradation of Stream's Designated Best Uses

The SRBC has been granted statutory authority to regulate the conservation, utilization, development, management, and control of water and related natural resources of the Susquehanna River Basin and the activities within the basin that potentially affect those resources. The SRBC regulations, policies and procedures collectively work to prevent the degradation of a stream's designated best use. The SRBC controls allocations, diversions, withdrawals, and releases of water in the basin to maintain the quantity and quality of the water. The SRBC Regulation of Projects (18CFR, Parts 801, 806, 807, and 808) provides the details of the programs and requirements that are in effect to achieve the goals of the commission. By effective exercise of its broad authority over water resources and related natural resources, extensive protocols and procedures, and monitoring programs, the SRBC is able to effectively prevent degradation of stream's designated best uses.

The DRBC's role in the protection of water resources and authority to protect those resources is analogous to that of the SRBC. Section 3.8 of the DRBC's Compact states "*No project having a substantial effect on the water resources of the basin shall hereafter be undertaken by any person, corporation or governmental authority unless it shall have been first submitted to and approved by the Commission, subject to the provisions of Sections 3.3 and 3.5. The Commission shall approve a project whenever it finds and determines that such project would not substantially impair or conflict with the Comprehensive Plan and may modify and approve as modified, or may disapprove any such project whenever it finds and determines that the project would substantially impair or conflict with such Plan*". DRBC regulations work collectively to protect Delaware River Basin stream's from sources of degradation that would affect the best usage. The DRBC Water Code (18 CFR Part 410) provides the regulations, requirements, and programs enacted into law that serve to facilitate the protection of these water resources in the Basin.

The NYSDEC has authority to control the use and protection of the waters of New York State through 6NYCRR, Part 608, Use and Protection of Waters. This regulation enables the agency to control any change, modification or disturbance to a "protected stream", which includes all navigable and any stream or portion of a stream with a classification or standard of AA, AA(t), A, A(t), B, B(t) or C(t), and "navigable waters". The agency reviews permits for changes, modifications, or disturbances to streams with respect to potential environmental impacts on aquatic, wetland and terrestrial habitats; unique and significant habitats; rare, threatened and endangered species habitats; water quality; hydrology; and water course and waterbody integrity. This process provides significant regulatory control to avoid degradation of a stream's designated best use.

3.4.3 Potential Impacts to Downstream Wetlands

The existence and sustainability of wetland habitats directly depend on surface water and/or ground water. As a result, wetlands potentially may be impacted by withdrawal of surface water or ground water. Wetlands can occur where surface water is impounded or the ground surface intercepts the ground water table. It is important to preserve the hydrologic conditions and to understand the surface water and ground water interaction to protect wetland areas.

DRBC regulations concerning potential impacts to downstream wetlands are located in the Delaware River Basin Water Code (18 CFR 410) addressed under Article 2.350, Wetlands Protection. It is the policy of the DRBC to support the preservation and protection of wetlands by:

1. Minimizing adverse alterations in the quantity and quality of the underlying soils and natural flow of waters that nourish wetlands;
2. Safeguarding against adverse draining, dredging or filling practices, liquid or solid waste management practices, and siltation;

3. Preventing the excessive addition of pesticides, salts or toxic materials arising from non-point source wastes; and
4. Preventing destructive construction activities generally.

Protection of public interest for wetland areas is paramount to the DRBC. Review and consideration of any project affecting wetlands must include a balanced assessment of the environmental and economic impact of the project. Encroachment on wetlands is not permitted unless it is determined that no feasible alternative exists and that overriding public interest has been demonstrated. Project encroachments must be planned, constructed and operated in a manner to protect the present and future public interest of such areas.

The DRBC reviews projects affecting 25 acres or more of wetlands (DRBC Water Code, Article2.350.4). Projects affecting less than 25 acres are reviewed by the DRBC only if no state or federal review and permit system is in place, and the project is determined to be of major significance by the DRBC. Additionally, the DRBC will review state or federal actions that may not adequately reflect the Commission's policy for wetlands in the basin.

SRBC regulations do not specifically target wetlands in the basin; however, the SRBC does have specific regulations regarding the management and protection of flood plains in the basin (SRBC Regulation of Projects, Article 801.8). The SRBC shall:

1. Encourage and coordinate the efforts of the signatory parties to control modification of the Susquehanna River and its tributaries by encroachment;
2. Plan and promote implementation of projects and programs of a structural and nonstructural nature for the protection of flood plains subject to frequent flooding; and
3. Assist in the study and classification of flood prone lands to ascertain the relative risk of flooding, and establish standards for flood plain management.

Projects requiring review and approval of the SRBC under Article 806.4, 806.5, or 806.6 are required to submit to the Commission a water withdrawal application. Applications are required to contain the anticipated impact of the proposed project on surface water characteristics, and on threatened or endangered species and their habitats (SRBC Regulation of Projects, Article 806.14). This requirement is protective of wetland habitats because it acknowledges that withdrawal of surface water or ground water potentially may alter the local hydrologic conditions which support wetland habitats.

NY State law protects certain freshwater wetlands under 6 NYCRR Parts 663, 664, and 665. Under Part 663.1, *"It is the public policy of the state, as set forth in the Freshwater Wetlands Act* (Environmental Conservation Law Article 24, and Article 71 Title 23), *to preserve, protect and conserve freshwater wetlands and the benefits derived therefrom, to prevent the despoliation and destruction of freshwater wetlands, and to regulate use and development of such wetlands to secure the natural benefits of freshwater wetlands, consistent with the general welfare and beneficial economic, social and agricultural development of the state."* The NYSDEC utilizes the Environmental Conservation Laws by implementing regulations that serve to define the procedural requirements for conducting activities in designated wetland areas, establishing standards governing the issuance of permits pursuant to this Act, and governing the Departments implementation of the Act. Wetlands classification criteria are defined in 6 NYCRR Part 664, and the statewide minimum land-use regulations for freshwater wetlands are contained in 6 NYCRR 663 and 665.

Permits must be obtained through the NYSDEC for any activities occurring in wetlands or within 100 feet of designated wetland areas (ECL 24-0501). Article 24 allows local governments to implement Article 24; therefore, there can be instances when permits must be obtained through these local governments.

3.4.4 Potential Impacts to Fish and Wildlife

DRBC regulations concerning the protection of fish and wildlife are located in the Delaware River Basin Water Code (18 CFR Part 410). In general, DRBC regulations require that the quality of waters in the Delaware basin be maintained *"in a safe and satisfactory condition…for wildlife, fish, and other aquatic life"* (DRBC Water Code, Article 2.200.1).

One of the primary goals of the DRBC is basin-wide water conservation, which is important for the sustainability of aquatic species and wildlife. Article 2.1.1 of the Water Code provides the basis for water conservation throughout the basin. Under Section A of this Article, water conservation methods will be applied to, *"reduce the likelihood of severe low stream flows that can adversely affect fish and wildlife resources"*. Article 2.1.2 outlines general requirements for achieving this goal, such as increased efficiency and use of improved technologies or practices.

All surface waters in the Delaware Basin are subject the water quality standards outlined in the Water Code. The quality of Basin waters, except intermittent streams, is required by Article 3.10.2B to be maintained in a safe and satisfactory condition for wildlife, fish and other aquatic life. Certain bodies of water in the Basin are classified as Special Protection Waters (also referred to as Outstanding Basin Waters and Significant Resource Waters) and are subject to more stringent water quality regulations. Article 3.10.3.A.2 defines Special Protection Waters as having especially high scenic, recreational, ecological, and/or water supply values. Per Article 3.10.3.A.2.b, no measureable change to existing water quality is permitted at these locations. Under certain circumstances wastewater may be discharged to Special Protection Areas within the watershed; however, it is discouraged and subject to review and approval by the Commission. These discharges are required to have a national pollutant discharge elimination system (NPDES) permit. Non-point source pollution within the Basin that discharges into Special Protection Areas must submit for approval a Non-Point Source Pollution Control Plan (DRBC Water Code, Article 3.10.3.A.2.e).

Interstate streams (tidal and non-tidal) and ground water (basin wide) water quality parameters are specifically regulated under the DRBC Water Code Articles 3.20, 3.30, and 3.40, respectively. Interstate non-tidal streams are required to be maintained in a safe and satisfactory condition for the maintenance and propagation of resident game fish and other aquatic life, maintenance and propagation of trout, spawning and nursery habitat for anadromous fish, and wildlife. Interstate tidal streams are required to be maintained in a safe and satisfactory condition for the maintenance and propagation of resident fish and other aquatic life, passage of anadromous fish, and wildlife. Ground water is required to be maintained in a safe and satisfactory condition for use as a source of surface water suitable for wildlife, fish and other aquatic life. It shall be *"free from substances or properties in concentrations or combinations which are toxic or harmful to human, animal, plant, or aquatic life, or that produce color, taste, or odor of the waters"* (DRBC Water Code, Article 3.30.4.A.1)

SRBC regulations concerning the protection of fish and wildlife are located in the Susquehanna River Basin Commission Regulation of Projects (18 CFR Parts 801, 806, 807, and 808). In general, the Commission promotes sound practices of watershed management for the purposes of improving fish and wildlife habitat (SRBC Regulation of Projects, Article 801.9).

Projects requiring review and approval of the SRBC under Article 806.4, 806.5, or 806.6 are required to submit to the Commission a water withdrawal application. Applications are required to contain the anticipated impact of the proposed project on fish and wildlife (SRBC Regulation of Projects, Article 806.14.b.1.v.C). *"The Commission may deny an application, limit or condition an approval to ensure that the withdrawal will not cause significant adverse impacts to the water resources of the basin."* (SRBC Regulation of Projects, Article 806.23.b.2). The Commission considers water quality degradation affecting fish, wildlife or other living resources or their habitat to be grounds for application denial.

Water withdrawal from the Susquehanna River Basin is governed by passby flow requirements that can be found in the SRBC Policy Document 2003-1, "Guidelines for Using and Determining Passby Flows and Conservation Releases for Surface-water and Ground-water Withdrawal Approvals". A passby flow is a prescribed quantity of flow that must be allowed to pass a prescribed point downstream from a water supply intake at any time during which a withdrawal is occurring. These requirements are prescribed in part to conserve fish and wildlife habitats. *"Approved surface-water withdrawals from small impoundments, intake dams, continuously flowing springs, or other intake structures in applicable streams will include conditions that require minimum passby flows. Approved ground water withdrawals from wells that, based on an analysis of the 120-day drawdown without recharge, impact streamflow, or for which a* *reversal of the hydraulic gradient adjacent to a stream (within the course of a 48-hour pumping test) is indicated, also will include conditions that require minimum passby flows."* (SRBC, Policy 2003-01). There are three exceptions to the required passby flow rules stated above:

1. If the surface-water withdrawal or ground-water withdrawal impact is minimal in comparison to the natural or continuously augmented flows of a stream or river, no passby flow will be required. Minimal is defined as 10 percent or less of the natural or continuously augmented 7-day, 10-year low flow (Q7-10) of the stream or river.
2. For projects requiring Commission review and approval for an existing surface-water withdrawal where a passby flow is required, as determined by these guidelines, but where a passby flow has historically not been maintained, withdrawals exceeding 10 percent of the Q7-10 low flow will be permitted whenever flows naturally exceed the passby flow requirement plus the taking. Whenever stream flows naturally drop below the passby flow requirement plus the taking, both the quantity and the rate of the withdrawal will be reduced to less than 10 percent of the Q7-10 low flow.
3. If a surface-water withdrawal is made from one or more impoundments (in series) fed by a stream, or if a ground-water withdrawal impacts one or more impoundments fed by a stream, a passby flow, as determined by the following criteria or the natural flow, whichever is less, will be maintained from the most downstream impoundment at all times during which there is inflow into the impoundment or series of impoundments.

In cases where passby flow is required, the following criteria are to be used to determine the appropriate passby flow for Exceptional Value (EV) Waters, High Quality (HQ) Waters, and Cold-Water Fishery (CWF) Waters. For EV Waters, withdrawals may not cause greater than five percent loss of habitat. For HQ Waters, withdrawals may not cause greater than five percent loss of habitat as well; however, a habitat loss of 7.5 percent may be allowed if:

1. The project is in compliance with the Commission's water conservation regulations of Section 804.20;
2. No feasible alternative source is available; and

3. Available project sources are used in a program of conjunctive use approved by the Commission, and combined alternative project source yields are inadequate.

For Class B, CWF Waters, withdrawals may not cause greater than a 10 percent loss of habitat. For Classes C and D, CWF Waters, withdrawals may not cause greater than a 15 percent loss of habitat. For areas of the Susquehanna River Basin not covered by the above regulations, the following shall apply:

1. On all EV and HQ streams, and those streams with naturally reproducing trout populations, a passby flow of 25 percent of average daily flow will be maintained downstream from the point of withdrawal whenever withdrawals are made.
2. On all streams not covered in Item 1 above and which are not degraded by acid mine drainage, a passby flow of 20 percent of average daily flow will be maintained downstream from the point of withdrawal whenever withdrawals are made. These streams generally include both trout stocking and warm-water fishery uses.
3. On all streams partially impaired by acid mine drainage, but in which some aquatic life exists, a passby flow of 15 percent of ADF will be maintained downstream from the point of withdrawal whenever withdrawals are made.
4. Under no conditions shall the passby flow be less than the Q7-10 flow.

Some NYSDEC regulations governing the protection of fish and wildlife are referenced in 6 NYCRR Parts 595 and 608. Part 595 governs the release of hazardous materials into the environment and would be applicable for the protection of fish and wildlife species. Under Part 595.2, it is unlawful to release hazardous substances or materials into the environment, unless a valid permit is obtained through State or Federal authorities. Releases must be reported to the NYSDEC under Part 595.3.

6 NYCRR Part 608 regulates the use and protection of waters in the state, and has subparts that address with the protection of fish and wildlife species. Under Part 608.2, "*No person or local*

public corporation may change, modify or disturb any protected stream, its bed or banks, nor remove from its bed or banks sand, gravel or other material, without a permit issued pursuant to this Part". Permit applications will be reviewed by the DEC to determine if proposed alterations to water resources are consistent with relevant standards (6 NYCRR 608.8) considering specified issues such as, "*the environmental impacts of a proposal, including effects on aquatic, wetland and terrestrial habitats; unique and significant habitats; and rare, threatened and endangered species habitats*".

3.4.5 Potential Aquifer Depletion

The depletion of an aquifer and a corresponding decline in the ground water level can occur when a well, or wells in an aquifer are pumped at a rate in excess of the recharge rate to the aquifer. It also is possible that aquifer depletion can occur if an excessive volume of water is removed from a surface water body that recharges an aquifer. Such an action would result in a reduction of recharge which could potentially deplete an aquifer. This "influent" condition of surface water recharging ground water occurs mainly in arid and semi-arid climates, and is not common in New York, except under conditions such as induced infiltration of surface water by aquifer withdrawal.

Aquifer depletion can lead to reduced discharge of ground water to streams and lakes, reduced water availability in wetland areas, and corresponding impacts to fish and wildlife that depend on these habitats. It is important to understand the hydrologic relationship between surface water, ground water, and wetlands within a watershed to appropriately manage rates and quantities of water withdrawal.

DRBC regulations concerning the mitigation of potential aquifer depletion are located in the Delaware River Basin Water Code (18 CFR Part 410). The protection of underground water is covered under Section 2.20 of the DRBC Water Code. Under Section 2.20.2, "*The underground water-bearing formations of the Basin, their waters, storage capacity, recharge areas, and ability to convey water shall be preserved and protected"*. Projects that withdraw underground waters must be planned and operated in a manner which will reasonably safeguard the present and future groundwater resources of the Basin. Ground water withdrawals from the Basin must not exceed sustainable limits. No ground water withdrawals may cause an aquifer systems supplies to become unreliable, or cause a progressive lowering of groundwater levels, water quality degradation, permanent loss of storage capacity, or substantial impact on low flows or perennial streams (DRBC Water Code, Article 2.20.4) Additionally, *"The principal natural recharge areas through which the underground waters of the Basin are replenished shall be protected from unreasonable interference with their recharge function"* (DRBC Water Code, Article 2.20.5).

The interference, impairment, penetration, or artificial recharge of groundwater resources in the basin are subject to review and evaluation by the DRBC. All owners of individual wells or groups of wells that withdraw an average of 10,000 gallons per day or more during any 30-day period from the underground waters of the Basin must register their wells with the designated agency of the state where the well is located. Registration may be filed by the agents of owners, including well drillers. Any well that is replaced or redrilled, or is modified to increase the withdrawal capacity of the well, must be registered with the designated state agency (Delaware Department of Natural Resources and Environmental Control; New Jersey Department of Environmental Protection; New York State Department of Environmental Conservation; or the Pennsylvania Department of Environmental Protection) (DRBC Water Code, Article 2.20.7).

Ground water withdrawals from aquifers in the Basin that exceed 100,000 gallons per day during any 30-day period must be metered, recorded, and reported to the designated state agencies. Withdrawals are to be measured by means of an automatic continuous recording device, flow meter, or other method, and must be measured to within five percent of actual flow. Withdrawals must be recorded on a biweekly basis and reported as monthly totals annually. More frequent recording or reporting may be required by the designated agency or the DRBC (DRBC Water Code, 2.50.2.A).

SRBC regulations concerning the mitigation of potential aquifer depletion are located in the Susquehanna River Basin Commission Regulation of Projects (18 CFR Parts 801, 806, 807, and 808). Projects seeking to withdraw water from the Susquehanna River Basin are required to conduct a constant-rate aquifer test prior to submission of the water withdrawal application (SRBC Regulation of Projects, Article 806.12). Before aquifer testing, a constant-rate test plan must be submitted to the SRBC for approval.

All project sponsors whose consumptive use of water is subject to review and approval of the SRBC must mitigate such consumptive use during conditions that would warrant mitigation. These regulations are set forth in Article 806.22 of the SRBC Regulation of Projects.

Under Article 806.23 of the Regulation of Projects (Standards for Water Withdrawals), the SRBC may limit withdrawals in the Basin if certain situations apply. "*The Commission may deny an application, limit or condition an approval to ensure that the withdrawal will not cause significant adverse impacts to the water resources of the basin. The Commission may consider, without limitation, the following in its consideration of adverse impacts: Lowering of groundwater or stream flow levels; rendering competing supplies unreliable; affecting other water uses; causing permanent loss of aquifer storage capacity; or affecting low flow of perennial or intermittent streams*" (SRBC Regulation of Projects, 806.23.b.2).

The SRBC may limit the quantity, timing or rate of water withdrawals, require alternate water supply sources, require implementation of monitoring measures, or require the implementation of an acceptable operations plan (SRBC Regulation of Projects, Article 806.23.b.3). The SRBC may require the investigation of additional sources or storage options to meet the demand of the project, or require the submittal of a water resource development plan that will include sufficient data to address any supply deficiencies, identify alternate water supply options, and support existing and proposed future withdrawals (SRBC Regulation of Projects, Article 806.23.b.4).

The concern for aquifer depletion due to increased ground water use in New York currently is being reviewed and addressed by the NYSDEC. The recently passed Title 33 legislation requires any entity that withdraws, or that has the capacity to withdraw, ground water or surface water in quantities greater than 100,000 gallons per day to file a report with the NYSDEC. The state currently regulates large public water supply groundwater withdrawals through the public water supply permit program (Environmental Conservation Law Article 15 Title 15). The NYSDEC also specifically regulates the significant public water supply ground water withdrawals on Long Island. The public water supply permit program protects and conserves available water supplies by ensuring fair and sensible use of these supplies by those who distribute potable water to the public for domestic, municipal, and other purposes. Other ground water withdrawals currently are unregulated unless the withdrawals occur within the lands regulated by the DRBC and the SRBC.

3.5 Cumulative Impacts of Multiple Water Withdrawals

An evaluation of the cumulative impacts of the anticipated water withdrawals was performed. This evaluation took into consideration the existing water usage, non-continuous nature of withdrawals and the natural replenishment of water resources. The DRBC and SRBC have developed regulations, policies, and procedures to characterize existing water use and track approved withdrawals. DRBC and SRBC jurisdiction does not extend to public water supplies that existed before the formation of the Commissions, unless changes are made to those water supply systems which would prompt a Commission review. Alpha's review of the requirements of the DRBC and SRBC indicates that the operators and the reviewing authority consider the following issues and information, and perform evaluations to assess the potential impacts of water withdrawal for unconventional well drilling.

- Comprehensive project description that includes a description of the proposed water withdrawal (location, volume, and rate) and its intended use;
- Existing water use in the withdrawal area;
- Potential impacts, both ecological and to existing users, from the new withdrawal;
- Availability of water resources (surface water and/or ground water) to support the proposed withdrawals;
- Availability of other water sources (e.g., treated waste water) and conservation plans to meet some or all of the water demand;
- Contingencies for low flow conditions that include passby flow criteria;
- Public notification requirements;

- Monitoring and reporting;
- Inspections;
- Mitigation measures;
- Supplemental investigations, including but not limited to, aquatic surveys;
- Potential impact to significant habitat and endangered rare or threatened species;
- Protection of subsurface infrastructure.

3.5.1 Existing Water Usage and Withdrawals

The DRBC and SRBC currently use a permit system and/or approval process that regulates existing water usage in their respective basins. The DRBC and SRBC require applications where operators provide a comprehensive project description that includes the description of the proposed withdrawals. The project information required includes site location, water source(s), withdrawal location(s), proposed timing and rate of water withdrawal and the anticipated project duration. The operators identify the amount of consumptive use (water not returned to the basin) and any import or export of water to or from the basin. The method of conveyance from the point(s) of withdrawal to the point(s) of use also is defined.

There is a monitoring and reporting requirement once the withdrawal and consumptive use for a project has been approved. This requirement includes metering withdrawals and consumptive use, and submitting quarterly reports to the commission. Monitoring requirements can include stream flow and stage measurements for surface water withdrawals and monitoring ground water levels for ground water withdrawals.

3.5.2 Withdrawals for High-Volume Hydraulic Fracturing

Surface water and ground water are withdrawn daily for a wide range of uses. New York ranks as one of the top states with respect to the total amount of water withdrawals. Figure 3-2 presents a graph indicating the total water withdrawal for New York is approximately 9,000 to

10,000 million gallons per day (MGD) (i.e., 9 to 10 billion), based on data from 2000 (USGS, 2009).

A graph showing the maximum approved daily consumptive use of water reported by the SRBC is shown in Figure 3-3. The largest consumptive identified use is for water supply (i.e., human consumption) at approximately 325 million gallons per day (MGD), followed by power generation at 150 MGD, and recreation at 50 MGD. The “current estimate” of water use for gas drilling is approximately 30 MGD, or less than 6 percent of the total use for water supply, power, and recreation.

The DRBC similarly reports on the withdrawal of water for various purposes. The daily water withdrawals, exports, and consumptive uses in the Delaware River Basin are shown in Figure 3-4. The total water withdrawal from the Delaware River Basin was 8,736 MGD, based on 2003 water use records. The highest water use was for thermoelectric power generation at 5,682 MGD (65%), followed by 875 MGD(10%) for public water supply, 650 MGD (7.4%) for New York City, 617 MGD (7 %) for hydroelectric, and 501 MGD (5.7%) for industrial purposes. The amount of water used for mining is 70 MGD (0.8%). The “mining” category typically includes withdrawals for oil and gas drilling; however, DRBC has not yet approved water withdrawal for Marcellus shale drilling operations. The information in Figure 3-4 shows that 4.3 percent (14 MGD) of the water withdrawn for consumptive use is for mining and 88 percent (650 MGD) of water exported from the Delaware River Basin is diverted to New York City.

The total volume of water to be withdrawn for horizontal well drilling and associated high volume hydraulic fracturing will not be known until applications are received and reviewed, and approved or rejected by the appropriate regulatory agency or agencies. DRBC has received an application (Docket no. D-2009-20-1) to withdraw up to 1.0 MGD of surface water from the West Branch Delaware River to support natural gas development and extraction activities in the Delaware River Basin for natural gas wells The proposed expiration date for the docket is September 23, 2014. SRBC approved gas drilling and hydrofracturing-related surface water withdrawals up to approximately 8.86 MGD from 18 separate locations and 9.24 MGD from 19 separate locations in Pennsylvania at the March 24 and June 18, 2009 Commission meetings

(SRBC, 2009). The approved volumes of the individual applications in 2009 are typical of previous withdrawals approved by the commission and range from 0.041MGD to 3.0 MGD

Comparison of the water withdrawal statistics with typical withdrawal volumes for natural gas drilling indicates that the historical percentage of water withdrawal for natural gas drilling is very low. The percentage of water withdrawal specifically for horizontal well drilling and high volume hydraulic hydrofracturing also is expected to be relatively low, compared with everyday water withdrawals.

The DRBC and the SRBC are requiring applications and Commission approval for all natural gas development projects within each's respective jurisdiction in New York. The executive director of the DRBC issued a statement on May 19, 2009 that natural gas extraction projects located in shale formations within the drainage area of the basin's special protection waters may not proceed until receiving approval from the Commission. DRBC Section 2.3.5B Rules of Practice and Procedure regulate the withdrawal of surface water or ground water for any purpose in quantities greater or equal to 100,000 gallons per 30 day period and the diversion of water into or out of the basin in quantities greater or equal to 100,000 gallons.

The SRBC specifically regulates consumptive water use of 20,000 gallons per day (gpd) or more during any consecutive 30-day period, water withdrawals of 100,000 gpd or more during any consecutive 30-day period, consumptive water use that involves surface water or groundwater withdrawals, any quantity involving a diversion into the basin, or 20,000 gallons per day or more (as the peak consecutive 30-day average) for diversion out of the basin. Furthermore, the SRBC has notified natural gas operators that any amount of water withdrawn to develop wells in the Marcellus or Utica shale formations in the Susquehanna watershed requires prior approval pursuant to 18 CFR, Section 806.5.

The application process begins with the operator providing the project information described above. The operators must demonstrate that the water resources exist to support the proposed withdrawal without adverse impacts. Adverse impacts include stream depletion, lowering of ground water levels, affecting existing water users, loss of aquifer storage capacity, affecting water quality (including upwelling that affects water temperature), and ecological impact (fish, aquatic organisms, habitat). An operator also must address consumptive use mitigation, especially during low flow conditions.

The evaluation of surface water resources to support a new or increased withdrawal is based on stream gauging records and the definition of low flow conditions. When stream gauging records are not available, the operator can use data for a stream with similar characteristics. A safe yield value, typically based on the 7-day, 10-year low flow value, is used to assess whether sufficient water resources are available, and to define passby requirements during low flow conditions.

Evaluation of ground water resources includes a ground water availability analysis based on ground water recharge potential. This analysis includes delineating the ground water recharge basin and recharge potential during drought conditions. An aquifer testing protocol is used to evaluate whether well(s) can provide the desired yield and assess the impacts of pumping. The protocol includes step drawdown testing and a constant rate pumping test. Monitoring requirements of ground water and surface water are described in the protocol and analysis of the test data is required. This analysis typically includes long term yield and drawdown projection and assessment of pumping impacts.

3.5.3 Water Resource Replenishment

The ability of surface water and ground water systems to support withdrawals for various purposes including natural gas development is based primarily on replenishment (recharge). The Northeast region typically receives ample precipitation that replenishes surface water (runoff and ground water discharge) and ground water (infiltration).

The amount of water available to replenish ground water and surface water depends on several factors and varies seasonally. A "water balance" (Thornthwaite and Mather, 1955, 1957) is a common, accepted method used to describe when the conditions allow ground water and surface water replenishment and to evaluate the amount of withdrawal that can be sustained. The primary factors included in a water balance are precipitation, temperature, vegetation, evaporation, transpiration, soil type, and slope.

Ground water recharge (replenishment) occurs when the amount of precipitation exceeds the losses due to evapotranspiration (evaporation and transpiration by plants) and water retained by soil moisture. Typically, losses due to evapotranspiration are large in the growing season, and consequently; less ground water recharge occurs. Ground water also is recharged by losses from streams, lakes, and rivers, either naturally (in influent stream conditions) or induced by pumping. The amount of ground water available from a well and the associated aquifer is typically determined by performing a pumping test to determine the "safe yield". The safe yield is the amount of ground water that can be withdrawn for an extended period without depleting the aquifer. Non-continuous withdrawal provides opportunities for water resources to recover during periods of non-pumping.

Surface water replenishment occurs directly from precipitation, from surface runoff, and by ground water discharge to surface water bodies. Surface runoff occurs when the amount of precipitation exceeds infiltration and evapotranspiration rates. Surface water runoff typically is greater during the non-growing season when there is little or no evapotranspiration, or where soil permeability is relatively low.

Short term variations in precipitation may result in droughts and floods which affect the amount of water available for ground water and surface water replenishment. Droughts of significant duration reduce the surplus amount of surface water and ground water available for withdrawal. Periods of drought may result in reduced stream flow, lowered lake levels, and reduced ground water levels until normal precipitation patterns return.

Floods may occur from short or long periods of above-normal precipitation. Flooding results in increased flow in streams and rivers and may increase levels in lakes and reservoirs. Periods of above-normal precipitation that may cause flooding also may result in increased ground water levels and greater availability of ground water. The duration of floods typically is relatively short compared to periods of drought.

The SRBC and DRBC have established evaluation processes and mitigation measures to assure adequate replenishment of water resources. The evaluation processes addresses recharge potential and low flow conditions. Examples of the mitigation measures utilized by the SRBC include:

- Replacement – release of storage or use of a temporary source
- Discontinue – specific to low flow periods
- Conservation releases
- Payments
- Alternatives – proposed by applicant

Operational conditions and mitigation requirements establish passby criteria and withdrawal limits during low flow conditions. A passby flow is a prescribed quantity of flow that must be allowed to pass an intake when withdrawal is occurring. Passby requirements also specify low flow conditions during which no water can be withdrawn.

3.5.4 Potential Impacts and Mitigation

There are several potential cumulative impacts from existing water use and new withdrawals associated with natural gas development, including, but not necessarily limited to:

- Stream flow and ground water depletion,
- Loss of aquifer storage capacity,
- Water quality degradation,
- Fish and aquatic organism impacts,
- Significant habitats, endangered, rare or threatened species impacts,
- Existing water users and reliability of their supplies,
- Underground infrastructure.

These impacts are addressed and mitigated by regulations, mitigation and conservation requirements described above that are currently in place for the Delaware River Basin by the DRBC and the Susquehanna River Basin by the SRBC.

3.5.5 Discussion of Cumulative Impacts of Multiple Water Withdrawals

The overall goal of the SRBC and DRBC is to conserve and protect the quantity and quality of the water and related natural resources of the respective basins. This evaluation indicates that project assessments, evaluations, and monitoring required by the DRBC and the SRBC to address the cumulative impacts of withdrawal appear to provide adequate protection. The SRBC (February, 2009) stated that “the cumulative impact of consumptive use by this new activity (natural gas development), while significant, appears to be manageable with the mitigation standards currently in place”.

The extent of the gas-producing shales in New York extends beyond the jurisdictional boundaries of the SRBC and the DRBC. The potential exists for gas drilling and associated water withdrawal to occur outside of the Susquehanna and Delaware River Basins. At this time, New York State regulations generally are not as comprehensive as those within the Susquehanna and Delaware River Basins with respect to controlling, evaluating, and monitoring surface water and ground water withdrawals for shale gas development. New York State could consider requiring evaluations, procedures and monitoring equivalent to those established by the SRBC and DRBC for drilling-related withdrawals that may be proposed in New York outside the jurisdictional boundaries of the Susquehanna and Delaware River basins.

3.6 Analysis of Recent Flood Events

A concern exists with respect to locating a multi-horizontal well drilling pad and associate operations within a floodplain. Flood water could potentially contact chemicals present on site or damage equipment and constructed facilities such as pits, tanks, impoundments, and berms. Similar concerns exist regarding permanent facilities associated with gas wells completed on a flood plain. Construction of well pads and access roads within a flood plain potentially may exacerbate flood conditions by changing the floodway configuration or redirecting the flow of water within the flood plain.

The Susquehanna and Delaware River Basins in New York are vulnerable to frequent, localized flash floods every year. These flash flood usually affect the small tributaries and can occur with little advance warning. Larger floods in some of the main stem reaches of these same river-basins also have been occurring more frequently. For example, the Delaware River in Delaware and Sullivan Counties experienced major flooding along the main stem and in its tributaries during more than one event from September 2004 through June 2006 (Schopp & Firda, 2008). Significant flooding also occurred along the Susquehanna River during this same time period.

The increased frequency and magnitude of flooding has raised a concern for unconventional gas drilling in the floodplains of these rivers and tributaries, and the recent flooding has identified concerns regarding the reliability of the existing Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps (FIRMs) that depict areas that are prone to flooding with a defined probability or recurrence interval. The concern focused on the Susquehanna and Delaware Rivers and associated tributaries in the Steuben, Chemung, Tioga, Broome, Chenango, Otsego, Delaware and Sullivan Counties, New York. The delineation of the Susquehanna and Delaware River Basins in New York are shown on Figure 3-5.

3.6.1 Flood Zone Mapping

Flood zones are geographic areas that the Federal Emergency Management Agency (FEMA) has defined according to varying levels of flood risk. These zones are depicted on a community's FIRM. Each zone reflects the severity or type of flooding in the area and the level of detailed analysis used to evaluate the flood zone.

Table 3.3 summarizes the availability of FIRMs for New York State as of July 23, 2009 (FEMA, 2009a). FIRMs are available for all communities in Broome, Delaware, and Sullivan County. The effective date of each FIRM is included on Table 3.3. As shown, many of the communities in New York use FIRMs with effective dates prior to the recent flood events. Natural and anthropogenic changes in stream morphology (e.g., channelization) and land use/land cover (e.g., deforestation due to fires or development) can affect the frequency and extent of flooding. For these reasons, FIRMs are updated periodically to reflect current information. Updating FIRMs and incorporation of recent flood data can take two to three years (FEMA, 2009b).

While the FIRMs are legal documents that depict flood-prone areas, the most up-to-date information on extent of recent flooding is most likely found at local or county-wide planning or emergency response departments (DRBC, 2009). Many of the areas within the Delaware and Susquehanna River Basins that were affected by the recent flooding of 2004 and 2006 lie outside the flood zones noted on the FIRMs (SRBC, 2009; DRBC, 2009; Delaware County 2009. Flood damage that occurs outside the flood zones often is related to inadequate maintenance or sizing of storm drain systems and is unrelated to streams. The FIRMs (as of July 23, 2009) do not reflect the recent flood data. Mapping the areas affected by recent flooding in the Susquehanna River Basin currently is underway and is scheduled to be published in late 2009 (SRBC, 2009). Updated FIRMs are being prepared for communities in Delaware County affected by recent flooding and are expected to be released in late 2009 (Delaware County, 2009).

3.6.2 Seasonal Analysis

The historic and recent flooding events do not show a seasonal trend. Flooding in Delaware County, which resulted in Presidential declarations of disaster and emergency between 1996 and 2006, occurred in January 1996, November 1996, July 1998, August 2003, October 2004, August 2004, and April 2005 (Tetra Tech, 2005). The Delaware River and many of its tributaries in Delaware and Sullivan counties experienced major flooding that caused extensive damage from September 2004 to June 2006 (Schopp & Firda, 2008). These data show that flooding is not limited to any particular season and may occur at any time during the year; therefore, stricter fluids containment focused toward seasonally recurring flooding will not be effective.

4.0 NEW YORK CITY WATERSHED

The NYCDEP's Watershed Rules and Regulations (WRR) do not address natural gas drilling or well permitting explicitly; however, the WRR address hazardous materials storage, radioactive materials disposal, storage of petroleum products, impervious surfaces, and stormwater pollution prevention plans, all of which may apply to activities at potential horizontal well drilling and hydraulic fracturing sites within the Watershed. Less likely activities include miscellaneous point sources and solid waste disposal. These Watershed Rules and Regulations that have some application to activities associated with potential shale gas drilling pads are found in Chapter 18, Subchapter C. Some of these regulations are stricter than NYSDEC's Oil and Gas Regulations (6 NYCRR Parts 550-559) and others simply have no counterpart in Parts 550-559. The following narrative summarizes the applicable WRR that are more stringent than the NYSDEC's current Oil and Gas regulations. Other NYSDEC and federal regulations exist in different programs that address most of the issues summarized herein, but a detailed comparison of other regulations was beyond the scope of this evaluation.

An analysis was conducted to determine whether the volume of frac-associated materials theoretically present on-site at any given time could be sufficient to cause degradation of New York City's (the City's) drinking water. The frac-associated materials on site include the various additives that are mixed with water to make the frac fluid and the water with residual additives that returns to the surface (flowback) for some time after fracing. The volume of a frac fluid or flowback water spill that would cause degradation to the City's drinking water was evaluated first, followed by an assessment of the probability of water quality impacts occurring to the West-of-Hudson drinking water sources. The probability analysis was based on available chemical data and reasonable assumptions.

4.1 Hazardous Materials

The State's Oil and Gas Regulations, Part 554.1(b), makes a general statement that "Pollution of the land and/or of surface or ground water resulting from exploration or drilling is prohibited." The WRRs, Section 18-32(a), more specifically states that the discharge or unsafe storage practices that are likely to lead to a discharge of hazardous substances or wastes into the environment (including into ground water) are prohibited.

Some additives used in frac fluid contain sufficient quantities of the substances listed in Table 1 of 6 NYCRR Part 597 that the additives would be considered hazardous substances, such as ethylene glycol and methanol. The presence of hazardous substances at the drill pad potentially could be subject to the Hazardous Substance Bulk Storage Regulations contained in 6 NYCRR Part 596; however, according to Part 596 (b)(3)(iii), the Part 596 regulations do not apply to a "non-stationary tank, barrel, drum, or other holding vessel unless used to store one thousand (1000) kilograms (2200 lbs) or more for a period of ninety (90) consecutive days or more." Most of the containers containing hazardous substances at the drill pad would not be regulated under Part 596, unless the containers were on site for 90 days or more. According to Section 18-32(a), because most of the containers are excluded from Part 596 and are therefore "not prohibited under state law," those tanks also do not fall under WRR Section 18-32 concerning Hazardous Substances and Hazardous Wastes, with the exception of "process tanks."

Process tanks, while specifically exempt from the Hazardous Substance Bulk Storage Regulations under 6 NYCRR Part 596.1(b)(3)(i), are not exempt from the WRRs in Section 18-32 concerning Hazardous Substances and Hazardous Wastes. A "process tank" is defined in 6 NYCRR Part 596.1(c)(35) as "a vessel or other equipment used to mix or physically, chemically or biologically change a hazardous substance. The term process tank does not include tanks used to store liquids containing hazardous substances prior to introduction into a process, or tanks used to store substances as intermediates, by-products or finished products of the process. Examples of process tanks include, but are not limited to, flow-through chemical reactor tanks, batch tanks and mixing hoppers. Feed tanks upstream of the process are considered storage tanks for the purposes of these regulations."

Most of the vessels used in the fracing process likely do not qualify as process tanks under Part 596; however, some frac companies do use mixing hoppers. Section 18-32 (b) of the WRR states that process tanks cannot be located within 100 feet of a watercourse (as defined in WRR Section 18-16) or a State regulated wetland, as mapped by the NYSDEC of 12.4 acres or more in size. Process tanks also cannot be located within 500 feet of a reservoir, reservoir stem, or a controlled lake (terms defined in WRR Section 18-16). These WRR restrictions on process tank locations are more stringent than the NYSDEC's Oil and Gas Regulations, which do not include process tank setbacks.

4.2 Radioactive Materials

Section 18-33 of the WRRs states that "a discharge, or storage which is reasonably likely to lead to a discharge, of radioactive materials into the environment (including into groundwater), and which is reasonably likely to cause degradation of surface water quality or of the water supply, is prohibited. It shall be an affirmative defense under this section that such discharge, or storage likely to lead to a discharge, is either permitted or not prohibited under federal law, and is either permitted or not prohibited under state law." The State's Oil and Gas Regulations do not specifically refer to discharge or storage of radioactive materials. Low-level, naturally occurring radioactive material (NORM) is present in many of the geological formations throughout much of New York. The development of natural gas wells into the Marcellus shale can bring low-level NORM to the surface through produced fluids or cuttings. Subpart 380-1.2(e) of 6 NYCRR indicates that Part 380 for the Prevention and Control of Environmental Pollution by Radioactive Materials "does not apply to NORM or materials containing NORM unless processed and concentrated"; consequently, the disposal of drill cuttings from the Marcellus or other gas shales in New York would not be subject to the 6 NYCRR Part 380 regulations. The drill cuttings generated, therefore, would not fall under WRR Section 18-33, and return of the drill cuttings to the ground at a drill pad site within the Watershed, also would not be prohibited.

NYSDOH and NYSDEC currently are evaluating analyses of a limited number of produced brine samples from vertical Marcellus wells in New York to determine the applicability of various regulations and the need for further data collection.

4.3 Petroleum Products

WRR Section 18-34 (a) provides general guidelines for the handling and storage of petroleum products within the NYC Watershed: "A discharge, or storage which is reasonably likely to lead to a discharge, of petroleum products into the environment (including into groundwater), and which is reasonably likely to cause degradation of surface water quality or the water supply, is prohibited." The Oil and Gas Regulations do not specifically refer to discharge of pollutants, other than the general statement that "Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited".

Most of Section 18-34 in the WRR does not apply to the storage of petroleum at potential drilling pads in the Watershed because the storage tanks are not stationary aboveground tanks as defined in 6 NYCRR Part 612. WRR Section 18-34(d) applies to any aboveground petroleum tank greater than 185 gallons in capacity not otherwise regulated under 6 NYCRR Part 612. This section is applicable specifically because the aboveground tanks at a drill pad do not require registration under Part 612. Section 18-34(d) prohibits the location of aboveground petroleum tanks within 25 feet of a watercourse or wetland, or within 300 feet of a reservoir, reservoir stem, or controlled lake. No corresponding setback requirements for petroleum storage tanks are found in the State's Oil and Gas Regulations.

4.4 Impervious Surfaces

Section 18-39 of the WRR addresses Stormwater Pollution Prevention Plans and Impervious Surfaces, neither of which are explicitly covered by the Oil and Gas Regulations. Impervious surfaces typically are not utilized at drill pads or the associated approaches, which are covered at the surface with coarse gravel, or permeable mats on top of gravel and a permeable geotextile fabric. Section 18-39 generally would not apply to drill pads, unless the site is covered with impervious surfaces. According to Section 18-16 (a)(48), "Impervious means resistant to penetration by moisture. Impervious materials include, but are not limited to, paving, concrete, asphalt, roofs, or other hard surfacing material. Impervious surfaces do not include dirt, crushed stone or gravel surfaces."

One aspect of Section 18-39 that may apply to shale gas drilling, regardless of the pervious nature of the drill pad surface, is contained in Section 18-39(a)(9), which states that "Construction of a bridge or crossing of a watercourse or wetland which does not require a permit from a regulatory agency other than the Department shall require the review and approval of the Department. Such bridge or crossing shall be constructed to prevent adverse impacts on the quality of the water supply". This regulation could apply during the construction of access roads.

4.5 Stormwater Pollution Prevention Plans

WRR Section 18-39 further details what activities require stormwater pollution prevention plans. Section 18-39(b)(3) states that "Stormwater pollution prevention plans shall be prepared for the activities listed in this paragraph. Such plans shall be prepared and implemented in accordance with the requirements of Part III of the New York State Department of Environmental Conservation General Permit No. GP-93-06 . Such plans shall also be subject to the prior review and approval of the Department." The NYSDEC has replaced the SPDES General Permit GP-93-06 for Runoff from Construction Activity with the SPDES General Permit GP-0-08-001 for Stormwater Discharges from Construction Activity since the promulgation of the WRR. The activities listed that apply to drilling pads and related access roads are found in WRR Section 18-39(b)(3)(i) and (iv), are as follows:

i) Plans for development or sale of land that will result in the disturbance of five (5) or more acres of total land area as described in General Permit No. GP-93-06;

iv) A land clearing or land grading project, involving two or more acres, located at least in part within the limiting distance of 100 feet of a watercourse or wetland, or within the limiting distance of 300 feet of a reservoir, reservoir stem or controlled lake, or on a slope exceeding 15 percent.

No stormwater pollution prevention plan would be required by WRR for constructing a drilling pad, provided its size and location do not exceed these limitations. If construction plans disturb areas beyond these limitations, additional WRR apply pertaining to stormwater pollution prevention plans. These regulations are enumerated in Section 18-39(b)(4-6) and Section 18-39(c and d).

The existing NYSDEC land disturbance threshold for filing SPDES permits is more stringent than the threshold in the WRR. A SPDES General Permit for Stormwater Discharges is required by the NYSDEC if the disturbance area is greater than one acre.

4.6 Miscellaneous Point Sources

Miscellaneous point sources are briefly covered in the NYC Watershed Rules and Regulations. Regulation 18-40 (a) prohibits the discharge from, or unsafe storage likely to lead to a discharge at, industrial facilities that is likely to cause degradation of surface water quality or of the water supply. Such a discharge, or storage likely to lead to a discharge, must be either permitted or not prohibited under State and Federal law. Regulation 18-40 (b) states that “Any new point source, excluding point sources otherwise regulated pursuant to these rules and regulations, is prohibited from discharging into a reservoir or controlled lake, reservoir stem, or wetland.” The State Oil and Gas regulations prohibit pollution but do not specifically refer to miscellaneous point source discharges.

4.7 Solid Waste

Discharge of solid waste is regulated under Section 18-41 of the WRR; however, it is not addressed in the Oil and Gas Regulations. Under Section 18-41 (b), “Discharge of solid waste directly into any watercourse, wetland, reservoir, reservoir stem or controlled lake is prohibited.” Section 18-41(c) states that “Only construction and demolition debris that is recognizable uncontaminated concrete, asphalt pavement, brick, soil, stone, trees or stumps, wood chips, or yard waste may be used as fill in the watershed." It is conceivable that fill activity could occur in the construction of access roads to the drill pads.

4.8 Watershed Water Quality Analysis

The New York City Watershed (the Watershed) is comprised of two primary components: the East-of-Hudson system and the West-of-Hudson (WOH) system. Only the WOH system overlies shale formations that potentially could be developed for gas drilling in New York State; consequently, the issues related to the potential impacts of horizontal drilling and high-volume hydro-fracing of shales herein is limited to the WOH Watershed.

The WOH Watershed contains six reservoirs that provide drinking water to New York City (the City). These reservoirs are the Ashokan, Cannonsville, Neversink, Pepacton, Rondout and Schoharie reservoirs (Figure 4-1). The total watershed area associated with these reservoirs is approximately 1549 square miles, exclusive of the 6 reservoirs (NYCDEP 2006). The total Watershed area protected by City and non-City entities, including the Catskill Forest Preserve, is 472 square miles, or 30.5% of the total Watershed area, exclusive of the 6 reservoirs. The "protected" areas within the Watershed are areas where shale gas development would be prohibited because the land is either protected by the City through fee or easement, or by non-City entities, which consist mostly of other public agencies (both State and local), land trusts and conservation entities. The entire Watershed area is within the fairways of shale gas development depicted in Figures 5-7 and 5-12; consequently, the 1,077 square miles of the Watershed that are not protected potentially are available to place well pads for the development of shale gas reservoirs.

The constituents of frac fluid additives were provided by suppliers in confidence to the NYSDEC. In this analysis, the constituents of the additives were reviewed to identify those with pertinent NYSDOH Maximum Contaminant Levels (MCLs) and NYSDEC Standards. The amount of these substances possibly present on site was evaluated. The theoretical concentration of each regulated substance in each of the six WOH reservoirs was calculated to approximate the effect on each reservoir if the entire volume of each were released from a drill pad. The "downstream," theoretical, chemical concentrations in the Delaware and Catskill systems were evaluated at the respective first outlets East of Hudson, as were the theoretical concentrations in the City's drinking water at the point of intake. The theoretical number of concurrent well pads necessary to generate the concentration necessary to exceed the MCLs or Standards for each regulated constituent was estimated. A similar analysis was undertaken for the flowback water, using some similar and different assumptions.

Assumptions of "worst case" scenarios were used to evaluate the amount of frac fluid additives and flowback constituents onsite, and that could theoretically degrade the water sources. The main assumptions within each of these analyses are detailed following each evaluation, as part of the probability analysis for each scenario, along with comments on the reasonableness of certain assumptions. Some of the assumptions and comments appear in multiple analyses and are repeated as applicable.

4.8.1 Frac Fluid

4.8.1.1 Frac Fluid Constituents

The service companies that perform the hydrofracturing operations and the chemical supply companies that manufacture the frac fluid additives provided the NYSDEC with information on the composition of typical slickwater frac fluids and frac fluid additives, respectively, proposed for use at vertical and horizontal wells in New York. The information provided for the frac fluid additives included Material Safety Data Sheets (MSDS) and chemical compositions. Approximately 99% (or more) of the frac fluid volume is comprised of water and sand. The remaining 1% typically consists of acids, breakers, bactericides, clay stabilizers, corrosion inhibitors, crosslinkers, friction reducers, gelling agents, iron control products, scale inhibitors, and surfactants. These substances and products are added to the frac fluid at different stages of the fracing process to result in a progressive series of effects that ultimately result in improved gas yields. Many of these same materials utilized in the vertical wells are proposed for use in the horizontal wells in shale.

The known additive constituents and corresponding New York State standards are included in Table 4.1, along with the constituents that have been detected in flowback water. A blank in the standards column for a particular substance indicates there is no applicable standard for that substance in New York State. Table 4.2 lists only the potential additive chemicals that have standards relevant in New York. EPA's Primary Standards for drinking water are not included in this table because the NYSDOH MCLs or NYSDEC standards are equivalent, or stricter than the EPA's standards. Chemicals that have only EPA Secondary Standards are not included in Table 4-2 because these standards are not enforceable and have not been adopted by the NYSDOH or the NYSDEC at this time.

4.8.1.2 Potential Amount of Frac Fluid Chemicals Present On Site

Two specific frac fluid mixes (amounts of specific additives) proposed for use in high-volume slickwater fracs in New York were provided by well operators on a per-well basis and consist of a large volume of water with the various additives. The specific constituents that comprise each of the additives were provided confidentially to the NYSDEC by the additive suppliers, along with each constituent's chemical composition by weight. These two frac fluids together contain 10 of the 45 chemicals with established NYSDOH MCLs or NYSDEC standards that have been identified in the various additives (Table 4.2) reportedly used in vertical and horizontal fracing. The following method was used to determine the potential amount of each frac fluid additive chemical that may be temporarily present at the drilling pad.

- Convert additive volume (provided by Chesapeake and Fortuna) to liters (L)
- Convert volume of additive (L) to weight in kilograms (Kg). This is accomplished by multiplying the volume (L) of the given additive by the specific gravity of the additive (from MSDS), resulting in total Kg of the additive in the frac fluid mix.

- Determine the Kg of each chemical in the additive by using percent-by-weight data given for each chemical (provided by the chemical suppliers) in the additive. This calculates the total weight (Kg) of each chemical in the frac fluid proposed for use in one horizontal well.
- Determine the maximum amount (Kg) of each chemical potentially present on site at a given time by multiplying the weight of each chemical in the frac fluid by one, two and eight. The factors of one and two are used to represent the range of likely amounts of the chemicals potentially present on site. The factor of eight is used to represent the anticipated maximum number of horizontal wells that may be needed to develop all the subsurface area within a square mile from a single pad.

The main assumption in this particular analysis is that the amount of each chemical on site at a given time will be the amount needed to perform all frac jobs on eight wells. The anticipated maximum number of wells necessary to cover the leased area is eight, within a one-square-mile unit, from a single pad. The average number of wells per pad may be less than eight due to lease limitations or if experience shows that fewer wells are needed to efficiently develop the resource. This results in a lower volume of chemicals theoretically present on site at any time. Moreover, each successive frac job performed at a drill pad reduces the potential maximum amount of acid subsequently present, as materials are consumed.

Although it is theoretically possible to have all the additives required for fracing all eight wells on the drill pad, it is highly unlikely to occur in practice. The typical practice and anticipated scenario is that the volume of additives required for each well will be delivered in phases as needed, and delivered within a narrow time frame for relatively immediate use. The current practice generally is to conduct phased well drilling and hydrofracturing, fracing one or two wells at one time due to space limitations on the drill pad. Hydrofracturing two wells is done by preparing to frac a stage in one well while conducting a frac on a stage in a second well, then continuing to alternate between the wells. Space onsite also is limited for storing the volume of water necessary to frac multiple wells at the same time because each well could require more than three million gallons of water.

4.8.1.3 Theoretical Concentration of Frac Fluid Chemicals in City Reservoirs

4.8.1.3.1 Non-Acid Frac Fluid Chemicals in City Reservoirs

The following methodology was employed to determine whether the potential volume of the non-acid chemicals in the frac fluid additives on-site at any given time theoretically is sufficient to cause degradation of the City's individual WOH drinking water sources. Degradation is considered herein to reflect contaminant concentrations in the reservoir or water supply that exceed MCLs or standards. The analysis is limited to the two frac fluid compositions that have been proposed for horizontal drilling in New York shale gas wells (Table 4-3).

- Assume that the total amount (Kg) of chemical present at the drill pad reflects the amount needed to complete one, two, or eight frac jobs on eight horizontal wells;
- Assume that the total amount (Kg) of chemical present at the well site for one, two, or eight frac jobs enters each reservoir directly and completely, with no evaporation of chemical, no dilution, no soil adsorption, no detection or recognition of a release, and no attempt made to mitigate the spill;
- Assume complete and instantaneous mixing of the chemical within the receiving reservoir;
- Determine the concentration of the chemical in the reservoir under drought conditions by comparing the amount of chemical spilled (mg) to the reservoir volume (L) during drought conditions (Table 4.3). The reservoir capacity during a drought was assumed to be one third of full capacity (Table 4.4). This is consistent with the lowest storage capacity on record for the current system since 1980 (NYCDEP Web Page: History of Drought and Water Consumption). Drought conditions represent the time when the reservoirs would be the most vulnerable to a spill since less water would be available for dilution.

The results of this analysis indicate that, using the above assumptions, the amount of several chemicals present on site to complete one frac job is sufficient that if a total release of an additive occurred to one of the smaller reservoirs, Standards theoretically could be exceeded in the Schoharie or Neversink reservoirs. The results also indicate that there theoretically could be a large enough quantity of additives present on site for eight wells such that a total release of an additive could cause at least one of the regulated chemicals to exceed MCLs or standards in any of the receiving reservoirs (Table 4.3). The probability of this occurring is unlikely, as discussed in the following comments provided for each of the assumptions.

Assumption: The quantity of chemicals or additives present on site will be the total amount needed to perform all frac jobs on eight wells.
C*omment*: As presented in section 4.8.1.2, it is not reasonable and highly unlikely that all of the additives necessary to complete all frac jobs on all eight wells will be present on site simultaneously. The likely scenario is that the delivery of additives required for each well will be phased as the additives are needed, and delivered in time for its use downhole. It is reasonably anticipated, based on current practices outside New York, that no more than two to three wells would be staged for contemporaneous hydrofracturing.

Assumption: The frac fluid or additive is spilled directly into a reservoir.
Comments: The existing regulations prohibit drilling of gas wells within 50 feet of municipal surface water supplies, and the existing GEIS recommends a setback of 150 feet. There is no reasonable mechanism for frac fluid or frac fluid additives to directly enter any of the NYC reservoirs. Moreover, the drill pad is constructed in accordance with a Stormwater Pollution Prevention Plan, which will be required by the NYSDEC for sites larger than one acre. The drill pad is constructed with a low berm around the site to prevent fluids from running into and out of the drill pad area. Concrete barriers, hay bales, and ditches also are employed to prevent fluid movement to and from the drill pad. It is not possible for any frac fluid or additive spill on site to enter a reservoir without necessarily first contacting the ground, thereby decreasing the potential amount of chemical entering a reservoir, in contrast to the assumption that the chemical is discharged directly into a reservoir.

Assumption: The entire amount of chemical, or additive, present on the drill pad is released to the reservoir.

Comments: It is extremely unlikely that the entire amount of any additive or chemical on site would be spilled at all, much less directly to one of the City's reservoirs. Non-acid chemicals and additives typically are brought to the site in multiple 230-gal to 250-gal totes, which are cube-like plastic tanks surrounded by protective steel caging, or in tanker trucks for larger volume liquids, or in steel tanks with secondary containment for temporary storage on site. The storage containers must meet USDOT or UN regulations for the respective chemicals. A chemical or additive could accidentally spill from a ruptured tote or container; however, it is unreasonable to expect all of the containers to breach simultaneously. Site personnel monitor the delivery and presence of hazardous materials (including signed manifests), and the on-site presence is limited to the short-term consumptive use, so it is highly unlikely that a catastrophic spill would be undiscovered.

There are controls in place to minimize potential spills, such as valves and gauges. The injection of additives into the frac process also is monitored and typically is performed within a closed system. The risk of a release of frac fluid or additives is further reduced by maintaining the frac fluid injection process within a closed system.

Assumption: No soil adsorption occurs
Comments: Soil adsorption is a process that will help mitigate potential spills because it is not possible for a spill to reach one of the City's reservoirs without first contacting soil. The process of soil adsorption would greatly reduce the risk of contaminants reaching a reservoir by reducing the potential amount of contaminant entering a reservoir compared with the assumption that the chemical could somehow be directly discharged to a reservoir.

Assumption: No evaporation occurs.
Comments: Evaporation of many non-acid chemicals, if spilled, would certainly occur during warmer seasons of the year, reducing the risk of contaminants reaching a reservoir. Chemicals dissolved in water also would be subject to evaporation, which would further reduce the potential concentrations remaining in the water.

Assumption: Complete and instantaneous mixing of the non-acid chemical occurs in the receiving reservoir

Comments: Complete and instantaneous mixing of non-acid chemicals is not likely to occur for a variety of physical and chemical reasons. For examples, different chemicals have different densities, solubilities, and rates of dispersion. Each of the WOH reservoirs has a unique areal geometry, with unique wind patterns, different tributaries, and different limnological aspects. All of these factors contribute to differing circulation and lake turnover patterns that affect the extent to which chemicals can mix within the reservoirs.

There also is natural attenuation which includes a variety of physical, chemical, or biological processes that, under favorable conditions, act without human intervention to reduce the mass, toxicity, volume, or concentration of contaminants (USEPA 1999). Some attenuation processes not identified elsewhere that may occur in the soil or water for specific constituents include biodegradation, volatilization, and chemical or biological stabilization, transformation, or destruction. Evaluating the degree to which individual chemicals in each of the reservoirs will mix, disperse, and attenuate under actual conditions is beyond the scope of this evaluation. Complete and instantaneous mixing was assumed to evaluate the theoretical water quality effect of chemical spills in the WOH reservoirs.

4.8.1.3.2 Acids

Acids, if spilled to a reservoir, would lower the pH of the water, but would not be detected by laboratory analysis in water samples, except indirectly by measuring pH; consequently, the potential for acids to impact the City's water sources was approached in a different manner than the non-acid chemicals. Acids commonly are used during an early stage in the frac process to clean up perforation intervals of cement and drilling mud prior to frac fluid injection. The process is used to treat the entire length of the borehole, which includes the casing.

The volume and types of acid used for a frac job varies between companies and techniques. Hydrochloric acid (HCl) is the strongest acid used in the frac process. Strong acids such as HCl dissociate almost completely when mixed with water, to the extent that the concentration of the undissociated portion becomes undetectable. Information on vertical wells already permitted and fractured in New York State prior to the dSGEIS process indicate that up to 5,000 gallons of 15% hydrochloric acid have been used for a single vertical well. The average depth of the Marcellus Formation where it is a target for gas production is approximately 4,500 feet in New York. A horizontal well in the Marcellus could have a horizontal component up to 4,500 feet, making the total well length twice the length of a vertical well, on average. The volume of 15% hydrochloric acid used on a horizontal shale well potentially could be 10,000 gallons, which is twice the amount used for a vertical well.

HCl is produced in solutions up to 38% for transportation of the chemical; consequently, the analysis provided herein assumes the concentration onsite is 38%. This concentration is consistent with information provided by one of the gas drilling companies (Fortuna), which stated that hydrochloric acid is transported to the site in stainless steel tanks, or tanker trucks, at 36% and mixed on-site to 15% for injection with frac fluid to clean the borehole (Kessey, 2009, pers. comm.). Approximately 4,000 gallons of 38% HCl is needed to mix with water to create 10,000 gallons of 15% HCl for injection. A total of approximately 32,000 gallons of 38% HCl potentially could be needed to clean out a total of 8 wells at a single drill pad.

The effect of a spill of hydrochloric acid (HCl) from a well pad directly to the City's reservoirs was analyzed The acceptable range of pH for the City's drinking water is 6.5 to 8.5 and is based on the EPA Secondary MCL for pH (NYCDEP, 2008). The evaluation assessed how much concentrated 38% HCl would be necessary to lower the pH of each reservoir from a conservatively assumed pH of 7 to 6.5, under the following "worst case" assumptions:

- Acid spilled directly to the reservoir,
- No spill detection,
- No attempt at mitigation,
- No soil adsorption,
- No soil or surface water buffering,
- No evaporation, and
- Complete and instantaneous mixing of acid in the reservoir

The results indicate that that the quantity of acid temporarily present to frac one well exceeds the theoretical volume necessary to degrade any of the City's water sources (WOH reservoirs) if a spill were to occur under these assumptions. The probability of an acid spill occurring under these conditions is unlikely, as discussed in the following comments that address the reasonableness of the assumptions used in this analysis.

Assumption: The acid spill is released directly into a water reservoir.
Comments: The existing Oil & Gas regulations prohibit drilling gas wells within 50 feet of municipal surface water supplies, and the existing GEIS recommends a 150-foot setback. There is no reasonable mechanism for an acid spill to directly enter any of the NYC reservoirs. The drill pad will be constructed in accordance with a Stormwater Pollution Prevention Plan for all sites larger than one acre. The drill pad is constructed with a low berm around the site to prevent fluids from running into and out of the drill pad area. Concrete barriers, hay bales, and ditches also are employed to prevent fluid movement to and from the drill pad. Any acid spill would necessarily contact the ground before entering a reservoir, thereby decreasing the potential amount of acid entering a reservoir, in contrast with the acid assumed to be discharged directly into a reservoir.

Assumption: No spill detection or attempt at mitigation
Comments: Acid typically arrives at the drill pad in tanks or tanker trucks that must meet federal or international regulations for the respective hazardous substance. Acid could accidentally spill from a breached tank; however, site personnel monitor the delivery and presence of hazardous materials such as acid (including signed manifests), and the on-site volume is limited to the short-term consumptive use, so it is highly unlikely that a significant spill would be undiscovered.

There also are controls in place to minimize the potential for spills, such as valves and gauges. Operators generally have buffering materials on site to help mitigate potential acid spills, such as bags of soda ash. The injection of additives such as acid into the frac fluid, and the injection of frac fluid into the well, is typically performed within a closed system which further reduces the risk of an acid spill.

Assumption: No soil adsorption occurs and there is no soil or water buffering capacity

Comments: Soil adsorption is a process that will help mitigate potential acid spills because it is not possible for a spill to reach one of the City's reservoirs without first contacting soil. The process of soil adsorption would greatly reduce the risk of an acid spill reaching a reservoir by reducing the potential amount of acid entering a reservoir compared with the assumption that the acid could somehow be directly discharged to a reservoir. It also is reasonable to expect that the soil and surface water both contain some degree of natural buffering capacity that will neutralize some percentage of the acid, thereby further reducing the overall theoretical impact.

Assumption: No evaporation of acid occurs.

Comments: Acids, particularly hydrochloric acid, have much higher evaporation rates than water. Evaporation of acids, if spilled, would certainly occur, especially during warmer seasons of the year, reducing the risk of an acid spill impacting a reservoir.

Assumption: Complete and instantaneous mixing of acid occurs in reservoir.

Comments: Similar to the non-acid frac fluid constituents (Section 4.8.1.3.1), complete and instantaneous mixing of acids also is not likely to occur for the same a variety of reasons. The dispersion of the dissociated acid will be controlled by the overall limnology of the individual reservoirs. Evaluating the degree to which acid spills in each of the reservoirs will mix and disperse under actual conditions is beyond the scope of this evaluation. Complete and instantaneous mixing of the acid was assumed to evaluate the theoretical effect of acid spills in the WOH reservoirs. The actual pH change in a reservoir from an acid spill would be much less than that assessed under the assumption of complete mixing.

4.8.1.4 Theoretical Concentration of Chemicals in Water at Outlets of Delaware and Catskill Aqueducts

The WOH watershed is comprised of the Catskill and Delaware Aqueduct and Tunnel systems (Figure 4-1). The Catskill System includes the Cannonsville, Pepacton, Neversink, and Rondout Reservoirs. The Cannonsville, Pepacton, and Neversink Reservoirs separately flow via tunnels into the Rondout Reservoir. The Catskill Aqueduct carries water from the WOH Catskill System and empties into the Kensico Reservoir, where it mixes with the water from the Delaware System (Figure 4-2). Two tunnels carry the Kensico water to the Hillview Reservoir, which is the last holding area prior to distribution throughout the City.

The Delaware System includes the Schoharie and Ashokan Reservoirs. Water from the Schoharie Reservoir flows through the Shandaken Tunnel and empties into the Esopus Creek, which flows into the Ashokan Reservoir. The Delaware Aqueduct carries water from the Ashokan Reservoir and delivers it to the West Branch reservoir east of the Hudson River. A second leg of the Delaware Aqueduct carries water from the West Branch Reservoir and delivers it to the Kensico Reservoir.

The theoretical concentration of frac fluid chemicals that may be present in the Catskill System water due to a catastrophic spill of frac fluid additives was evaluated to assess whether the MCLs for the chemicals would be exceeded. The analysis evaluated the theoretical concentrations for the point at which the water enters the Kensico Reservoir, prior to mixing with the Delaware System Water. This is an important location for such an evaluation because it presents a potential decision-making opportunity for the City regarding the need to bypass the Catskill System should a catastrophic spill occur. Similarly, the theoretical concentration of frac fluid chemicals in the Delaware System water was evaluated for the first outlet east of the Hudson River at the West Branch Reservoir.

The following methodology was employed to determine whether the potential volume of frac fluid chemicals on-site at any given time theoretically is sufficient to cause degradation of the City's drinking water at the first outlet of each water system (Catskill and Delaware) east of the Hudson. The analysis is limited to those chemicals contained within the two frac fluid compositions that have been proposed for drilling horizontal shale gas wells in New York State.

- Calculate the theoretical concentration of chemicals at the outlet of the Catskill Aqueduct by comparing maximum chemical amount (mg) possibly present to complete one, two or eight frac jobs, to the total reservoir volume of the Schoharie and Ashokan reservoirs.

This approximates the theoretical concentration in the Catskill System as it enters the Kensico Reservoir.

- Calculate the theoretical concentration of chemicals at the outlet of the Delaware Aqueduct by comparing maximum chemical amount (mg) possibly present to complete one, two or eight frac jobs, to the total reservoir volume of the Cannonsville, Pepacton, Neversink and Rondout reservoirs. This approximates the theoretical concentration in the Delaware System as it enters the West Branch Reservoir.

The results of this analysis are presented in Table 4.5. The results indicate that, under all the assumptions in Sections 4.8.1.2, 4.8.1.3 and this Section (4.8.1.4), the amount of additives necessary to complete frac jobs on eight horizontal wells at one drill pad theoretically could be enough such that a complete release of an additive could cause certain regulated chemicals to exceed MCLs or standards at the outlets of the Catskill and Delaware systems, east of the Hudson River. The analysis indicates that the Catskill System is more sensitive to frac fluid additive releases than the Delaware System due the smaller volume of water in that System. Four chemicals listed in Table 4.5 could theoretically exceed MCLs in the Catskill System (Kensico Reservoir), and one chemical could theoretically exceed the MCL in the Delaware System (West Branch Reservoir). The amount of chemicals potentially on site to complete frac jobs on one or two wells is insufficient to cause degradation to either of the WOH systems at their EOH outlets.

Assumptions and Comments: As all of the assumptions presented in Sections 4.8.1.2 and 4.8.1.3 also apply to this analysis. Accordingly, all of the preceding comments regarding the improbability of those assumptions also apply and are not repeated here. An additional assumption in this analysis that warrants further discussion is the assumption that all of the City's reservoirs are considered to be at 33% capacity to simulate severe drought conditions, when the volume of water available for dilution is at a minimum. Drought conditions are not likely to affect all the reservoirs within the Catskill or Delaware Systems to the same degree (i.e., 33%) at the same time.

It is reasonable to anticipate that at least some of the reservoirs would be at a higher capacity than others during a drought, especially the downstream reservoirs such as the Ashokan and the Rondout. This reasonable scenario would result in a greater volume of water within the whole system, which would further dilute the theoretical concentration of any particular chemical at the EOH outlets.

4.8.1.5 Theoretical Concentration of Chemicals in the City's Drinking Water

The potential concentration of a particular frac fluid chemical in the NYC water supply at the Hillview Reservoir was evaluated because the Hillview Reservoir is the last holding area for water from the Catskill and Delaware Systems prior to distribution throughout the City. The Hillview Reservoir water quality represents the most conservative approximation of water quality that the City residents could consume.

This analysis was performed by comparing the maximum amount of chemical possibly present (mg) to complete frac jobs on one, two or eight wells, to the total drought volume of the Catskill and Delaware Systems (the six WOH reservoirs), plus the drought volumes of the EOH reservoirs which receive these waters (Table 4.5). The receiving reservoirs are the West Branch Reservoir and the Kensico Reservoir. The Hillview Reservoir is a holding basin and has no watershed beyond its immediate water surface area; therefore, the Hillview Reservoir water volume was not included in calculating the theoretical contaminant concentrations because it simply receives water directly from the Catskill and Delaware Systems.

The results of this analysis are presented in Table 4.5. The results in Table 4.5 indicate that none of the chemicals would be present in the Hillview reservoir at concentrations sufficient to exceed the NYSDOH MCLs. It would require multiple, contemporaneous, undetected, unmitigated, and catastrophic releases from multiple well pads to potentially impact the City's water supply at the Hillview Reservoir to the extent that MCLs would be exceeded.

Assumptions and Comments: Similar to the previous analysis regarding theoretical concentrations at the EOH outlets, all of the assumptions presented in Sections 4.8.1.2 and

4.8.1.3 also apply to this analysis. All of the comments regarding the improbability of those assumptions also apply and are not repeated here. The additional assumption that all the reservoirs are considered to be at 33% capacity to simulate drought conditions also is improbable and bears repeating regarding theoretical chemical concentrations in the Hillview reservoir. Severe drought conditions are not likely to affect all the reservoirs within the Catskill or Delaware Systems to the same degree (i.e., 33%) at the same time.

It is reasonable to expect that at least some of the reservoirs would be at a higher capacity than others during a drought, especially the downstream reservoirs such as the Ashokan and the Rondout, and the receiving reservoirs east of the Hudson River (Kensico and West Branch Reservoirs). Although the conservative analysis indicates no chemical concentrations would exceed the MCLs at the Hillview Reservoir, a reasonable drought scenario would result in a greater volume of water within the entire system, which would further dilute the theoretical concentration of any particular chemical in the City's drinking water at the Hillview Reservoir intakes.

4.8.2 Flowback Water

4.8.2.1 Flowback Water Constituents

Flowback water in shale gas drilling is water that returns to the surface due to the process of completing the gas well and putting it into production. The amount of flowback typically starts out at higher rates for the first two to three weeks after fracing and subsequently declines. The flowback water typically is present on site either in frac tanks, or in a constructed and lined containment. Centralized offsite storage in engineered impoundments also is under consideration, but is not reviewed herein. The on-site storage of the flowback water is temporary and the flowback is either recycled for future use in frac fluid or disposed off site. The flowback water after hydrofracing can contain some of the additive chemicals from the frac fluid, and chemicals created from the chemical reactions that occur from the contact of frac fluids with the shale and natural formation water in the shale. Naturally-occurring chemicals and substances in the shale formation also can be present in the flowback water.

All the chemicals that have been detected in flowback water samples, or are present in frac fluid additives, are listed in Table 4.1, along with the associated New York State standards. The reviewed flowback data was provided by four different shale gas drilling companies, and included 214 samples from 22 different Marcellus shale gas wells in NY, WV and PA. A summary of average concentrations of a limited set of parameters representing 62 tests from 25 different shale gas wells in southwestern Pennsylvania (Gaudlip, Paugh, and Hayes, 2008) also was reviewed.

Table 4.6 lists the chemicals that have been detected in flowback water and that have standards relevant in New York. EPA's Primary Standards for drinking water are not included in this table because the NYSDOH or NYSDEC standards are equivalent, or stricter than the EPA's standards. Substances that have only EPA Secondary Standards are not included in Table 4.6 because these standards are not enforceable and have not been adopted by the NYSDOH or the NYSDEC at this time. Table 4.6 also lists the maximum concentration reported for each regulated parameter detected in the flowback water samples.

4.8.2.2 Theoretical Concentration of Flowback Chemicals in City Reservoirs

Certain assumptions were made in the evaluation of the potential for flowback water to cause degradation to the City's water supply or water sources. A spill of 40,000 gallons was considered for purposes of this analysis. This spill is equivalent to the volume contained in two frac tanks, which typically each hold approximately 20,000 gallons. As with the frac fluid analysis, the release of the 40,000 gallons of flowback water is assumed to enter directly into a reservoir, under drought conditions, with no detection or attempt to mitigate the spill, no soil adsorption, no chemical evaporation, and complete and instantaneous mixing within the reservoir system.

The amount of regulated chemicals contained in 40,000 gallons of flowback water (two 20,000-gal tanks) was calculated based on the maximum concentrations reported in the lab samples (Table 4.6). The calculated amount of each chemical in the two tanks then was used to evaluate the potential concentration in each of the six WOH reservoirs if a direct spill of the entire 40,000 gallons occurred under severe drought conditions (Table 4.7).

Table 4.7 indicates that a direct spill of 40,000 gallons of flowback water would not result in reservoir concentrations at, or above, the MCLs or Standards for the regulated parameters that were detected in flowback water samples. This finding is consistent with the fact that the flowback water chemistry is very dilute. Because none of the parameters would exceed MCLs and Standards in the individual reservoirs, the corresponding theoretical concentrations downstream at the EOH outlets and at the Hillview Reservoir intakes would be significantly more dilute in chemical concentrations than at the individual reservoirs, and also would not exceed MCLs or Standards for any of the parameters. Multiple, simultaneous, undetected, 40,000-gallon spills of flowback water would have to occur to cause degradation of the City's water sources to the extent that MCLs or standards would be exceeded.

4.8.2.3 Probability Analysis With Respect to Flowback Water

It was calculated that the flowback water has much less potential to degrade the City's water sources than the frac fluid additives due to the much lower concentration of substances in the flowback water than in the fracing fluid. The above analysis indicates that the flowback water that might be present temporarily at well pads would not potentially degrade West-of-Hudson drinking water sources, even if a significant volume (40,000 gallons) of flowback water were spilled. The flowback water does not contain chemicals in sufficient concentrations to cause the water quality in the NYC reservoirs to exceed MCLs or Standards, under the theoretical and unlikely assumptions that were used in the analysis.

The "worst case" assumptions were: that two, 20,000-gallon tanks of flowback water were spilled directly to one of the City's reservoirs; that the concentration of each chemical in the flowback water was at the maximum laboratory concentration reported to date; that the spill went completely undetected and that not attempts at mitigation were made; that no evaporation of the flowback water occurred; that no soil adsorption of the flowback water occurred; that complete mixing of the flowback water occurred within the reservoir system; and that the reservoir systems are under severe drought conditions (33% capacity). The likelihood and reasonableness of each assumption is discussed in the following comments.

Assumption: The flowback water is spilled directly into a water reservoir.
Comments: The existing regulations prohibit drilling gas wells within 50 feet of municipal surface water supplies, and the existing GEIS recommends a setback of 150 feet. There is no reasonable mechanism for flowback water to directly enter any of the NYC reservoirs. The drill pad is constructed in accordance with a Stormwater Pollution Prevention Plan, which will be required for drill pads larger than one acre. The drill pad is constructed with a low berm around the site, which would prevent flowback water from running into and out of the drill pad area. Concrete barriers, hay bales, and ditches also are employed to prevent fluid movement to and from the drill pad. Any flowback water would necessarily contact the ground before entering a reservoir, thereby decreasing the potential amount of flowback water entering a reservoir, in contrast to being discharged directly into a reservoir.

Assumption: The total volume of two 20,000 gallon tanks of flowback water is released to the reservoir.
Comments: It is extremely unlikely that the entire contents of a frac tank, much less two tanks, would be spilled. There are controls in place to mitigate spills, such as valves and gauges. The flowback water typically is contained within a closed system, with flowback water directed via piping from the wellhead to frac tanks, although the practice of directing flowback water to lined containment areas is a potential option. Flowback water is present on site within the frac tanks for a limited period of time, further reducing the risk of a release.

Assumption: Maximum concentrations of the regulated chemicals detected in flowback water were used to determine the amount of chemicals present in two 20,000-gallon tanks.
Comments: The concentration of chemicals in the tanks of flowback water necessarily would be less than the maximum concentration detected in the flowback water samples because the

concentration of each substance changes with time. Some chemicals in the flowback water are detected at higher concentrations and then diminish with time, and other chemicals increase in concentration with time. The volume, or rate, of flowback water also changes with time, starting out at a high rate, typically of hundreds of barrels per day, and diminishing over a few weeks to typically less than 100 barrels per day. The flowback water contained in any frac tank would inherently contain a lower average concentration of a substance than the maximum that was assumed for the theoretical analysis.

Assumption: The release of 40,000 gallons of flowback water went completely undetected and no attempts at mitigation were made.
Comments: It is unreasonable to anticipate that a flowback volume equivalent to two 20,000 gallon frac tanks would be spilled without being detected. There are gauges to monitor tank contents and valves to shut down a potential release from a tank. Operators have multiple systems on site for spill control and mitigation. Attempts to stop and mitigate an observed spill would begin immediately, reducing the potential for the entire volume of spill reaching a reservoir.

Assumption: No soil adsorption occurs
Comments: Soil adsorption is a process that will help mitigate potential spills because it would be impossible for a spill of flowback water to reach one of the City's reservoirs without first contacting soil. The process of soil adsorption would greatly reduce the risk of flowback water reaching a reservoir by reducing the potential amount of constituents entering a reservoir, compared with the assumption that the flowback water somehow could be directly discharged to a reservoir.

Assumption: No evaporation of flowback water occurs.
Comments: Flowback water would be subject to evaporation, which may reduce the potential concentrations of some constituents remaining in the water; however, concentrations of specific constituents may increase. A detailed analysis of the net effect of evaporative conditions for specific chemicals and other processes that act to decrease concentrations such as natural attenuation is beyond the scope of this evaluation.

Assumption: Complete mixing of the flowback water occurs within the reservoirs.

Comments: As with the non-acid frac fluid chemicals discussed in Section 4.8.1.3.1, and the acids discussed in Section 4.8.1.3.2, complete mixing of the flowback water constituents also is not likely to occur for the same variety of reasons. The dispersion of flowback water chemicals will be controlled by the overall limnology of the individual reservoirs. Evaluating the degree to which flowback water releases to each of the reservoirs will mix, disperse, and attenuate under actual conditions is beyond the scope of this evaluation. Complete mixing of the flowback water was assumed to evaluate the theoretical effect of flowback spills in the WOH reservoirs.

Assumption: All of the City's reservoirs are considered to be at 33% of full capacity to simulate severe drought conditions, when the volume of water available for dilution is at a minimum.

Comments: Drought conditions are not likely to affect all six reservoirs to the same degree (i.e., 33%) at the same time. It is reasonable to expect that at least some of the reservoirs would be at a higher capacity than others during a drought, especially the EOH receiving reservoirs (West Branch and Kensico). Although the conservative analysis of a theoretical flowback water spill indicates that no chemicals would be found at concentrations that exceed the MCLs in the reservoirs or in the EOH outlets, reasonable drought conditions would result in a greater volume of water within the system as a whole, which would further dilute the concentration of any particular flowback water constituent in the City's drinking water at the Hillview Reservoir intakes.

4.9 Adequacy of Existing Regulations for to Protecting NYC Water Supply

New York City's drinking water sources and water supplies are subject to the NYCDEP's Watershed Rules and Regulations and the Delaware River Basin Commission's regulations, procedures and programs, in addition to the applicable regulations, policies, and guidelines of the NYSDEC (various divisions), NYSDOH, and USEPA. Local governments and agencies also may exert some control concerning specific activities within their respective jurisdiction, such as road use. The regulations, standards, policies, programs, and procedures of these various federal, state, and local authorities cover a myriad of physical, chemical, and biological aspects that directly and indirectly protect the quantity and quality of the City's drinking water.

Activities within the NYC watershed that are deemed to potentially affect the City's water supplies require extensive documentation, reviews, and permits, as applicable to the proposed activity. Drilling and high-volume hydrofracturing for horizontal shale gas wells is an activity that will require approval and compliance with multiple authorities. Unless prohibited by law or waived, the more stringent of the applicable regulatory criteria and standards will apply, where there are similar or overlapping programs and policies.

Alpha's review of the existing authorities (Sections 3 and 4) indicates that the City's water supply is adequately protected regarding water quality and quantity. New York City's control of a substantial amount of acreage surrounding the reservoirs through fee ownership or conservation easements provides further protection. Drilling and high-volume hydrofracing cannot occur on such acreage without the City's permission.

Alpha has recommended in Section 2.14 that certain practices be adopted to provide additional protection to surface water and ground water from chemical spills. These practices would apply to natural gas drilling operations throughout the State, including the NYC watershed. The recommendations incorporate flexibility, so that the majority of conditions specific and applicable to the anticipated activities by an applicant under the SGEIS can be covered to the extent practical.

5.0 GEOLOGY

The natural gas industry in the US began in 1821 with a well completed by William Aaron Hart in the upper Devonian Dunkirk Shale in Chautauqua County. The "Hart" well supplied businesses and residents in Fredonia, New York with natural gas for 37 years. Hundreds of shallow wells were drilled in the following years into the shale along Lake Erie and then southeastward into western New York. Shale gas fields development spread into Pennsylvania, Ohio, Indiana, and Kentucky. Gas has been produced from the Marcellus since 1880 when the first well was completed in the Naples field in Ontario County. Eventually, as other formations were explored, the more productive conventional oil and natural gas fields were developed and shale gas (unconventional natural gas) exploration diminished.

The US Energy Research and Development Administration (ERDA) began to evaluate gas resources in the US in the late 1960s. The Eastern Gas Shales Project was initiated in 1976 by the ERDA (later the US Department of Energy) to assess Devonian and Mississippian black shales. The studies concluded that significant natural gas resources were present in these tight formations.

The interest in development of shale gas resources increased in the late 20th and early 21st century as the result of an increase in energy demand and technological advances in drilling and well stimulation. The total unconventional natural gas production in the US increased by 65% and the proportion of unconventional gas production to total gas production increased from 28% in 1998 to 46% in 2007 (Arthur et al., 2008).

A description of New York State geology and its relationship to oil, gas, and salt production is included in the 1992 GEIS. The geologic discussion provided herein supplements the information as it pertains to gas potential from unconventional gas resources. Emphasis is placed on the Utica and Marcellus shales because of the widespread distribution of these units in New York.

5.1 Black Shales

Black shales are fine-grained sedimentary rocks that contain high levels of organic carbon. The fine-grained material and organic matter accumulate in deep, warm, quiescent marine basins. The warm climate favors the proliferation of plant and animal life. The deep basins allow for an upper aerobic (oxygenated) zone that supports life and a deeper anaerobic (oxygen-depleted) zone that inhibits decay of accumulated organic matter. The organic matter is incorporated into the accumulating sediments and is buried. Pressure and temperature increase and the organic matter is transformed by slow chemical reactions into liquid and gaseous petroleum compounds as the sediments are buried deeper. The degree to which the organic matter is converted is dependent on the maximum temperature, pressure, and burial depth. The extent that these processes have transformed the carbon in the shale is represented by the thermal maturity and transformation ratio of the carbon. The more favorable gas producing shales occur where the total organic carbon (TOC) content is at least 2% and where there is evidence that a significant amount of gas has formed and been preserved from the TOC during thermal maturation (Nyahay et al., 2007).

Oil and gas are stored in isolated pore spaces or fractures and adsorbed on the mineral grains (Engelder & Lash, 2008). Porosity (a measure of the void spaces in a material) is low in shales and is typically in the range of 0 to 10 percent (Freeze & Cherry, 1979). Porosity values of 1 to 3 percent are reported for Devonian shales in the Appalachian Basin (Charpentier et al., 1982). Permeability (a measure of a material's ability to transmit fluids) is also low in shales and is typically between 0.1 to 0.00001 millidarcy (md) (Freeze and Cherry, 1979). Hill et al. (2002) summarized the findings of studies sponsored by NYSERDA that evaluated the properties of the Marcellus shale. The porosity of core samples from the Marcellus in one well in New York ranged from 0 to 18%. The permeability of Marcellus shale ranged from 0.0041 md to 0.216 md in three wells in New York State.

Black shale typically contains trace levels of uranium that is associated with organic matter in the shale (Charpentier, et al., 1982). The presence of naturally occurring radioactive materials (NORM) induce a response on gamma-ray geophysical logs and is used to identify, map, and determine thickness of gas shales.

The Appalachian Basin was a tropical inland sea that extended from New York to Alabama (Figure 5-1). The tropical climate of the ancient Appalachian Basin provided favorable conditions for generating the organic matter, and the erosion of the mountains and highlands bordering the basin provided clastic material for deposition. The sedimentary rocks that fill the basin include shales, siltstones, sandstones, evaporites, and limestones that were deposited as distinct layers that represent several sequences of sea level rise and fall. Several black shale formations, which may produce natural gas, are included in these layers (Lash, 2009).

The stratigraphic column for New York State is shown in Figure 5-2 and includes oil and gas producing horizons. Figure 5-3 is a generalized cross-section from west to east across the southern tier of New York State and shows the variation of thickness and depth of the various stratigraphic units.

The Ordovician-aged Utica shale and the Devonian-aged Marcellus shale are of particular interest because of recent estimates of natural gas resources and because these units are found widespread throughout the Appalachian Basin from New York to Tennessee. There are a number of other black shale formations (Figures 5-2 and 5-3) in New York that may produce natural gas on a localized basis (NYSERDA, 2002). The following sections describe the Utica and Marcellus shales in greater detail.

5.2 Utica Shale

The Utica shale is an upper Ordovician-aged black shale that extends across the Appalachian Plateau from New York and Quebec, Canada, south to Tennessee. The Utica shale covers approximately 28,500 square miles in New York and extends from the Adirondack Mountains to the southern tier and east to the Catskill front (Figure 5-4). The Utica shale is exposed in outcrops along the southern and western Adirondack Mountains, and it dips gently south to depths of more than 9,000 feet in the southern tier of New York.

The Utica shale is a massive, fossiliferous, organic-rich, thermally-mature, black to gray shale. The sediment comprising the Utica shale was derived from the erosion of the Taconic Mountains at the end of the Ordovician, approximately 440 to 460 million years ago. The shale is bounded below by Trenton Group strata and above by the Lorraine Formation and consists of three members in New York State that include: Flat Creek Member (oldest), Dolgeville Member, and the Indian Castle Member (youngest) (Smith & Leone, 2009). The Canajoharie shale and Snake

Hill shale are found in the eastern part of the state and are lithologically equivalent, but older than the western portions of the Utica (Fisher, 1977).

There is some disagreement over the division of the Utica shale members. Smith & Leone (2009) divide the Indian Castle Member into an upper low-organic carbon regional shale and a high-organic carbon lower Indian Castle. Nyahay et al. (2007) combines the lower Indian Castle Member with the Dolgeville Member. Fisher (1977) includes the Dolgeville as a member of the Trenton Group. The stratigraphic convention of Smith and Leone is used in this document.

Units of the Utica shale have abundant pyrite, which indicate deposition under anoxic conditions. Geophysical logs and cutting analyses indicate that the Utica shale has a low bulk density and a high total organic carbon content (Smith & Leone, 2009).

The Flat Creek and Dolgeville Members are found south and east of a line extending approximately from Steuben County to Oneida County (Figure 5-4). The Dolgeville is an interbedded limestone and shale. The Flat Creek is a dark calcareous shale in its western extent and grades to a argillaceous calcareous mudstone to the east. These two members are time-equivalent and grade laterally toward the west into Trenton limestones (Smith & Leone, 2009; Nyahay et al., 2007). The lower Indian Castle Member is a fissile black shale and is exposed in road cuts, particularly at the New York State Thruway (I-90) exit 29A in Little Falls. Figure 5-5 shows the depth to the base of the Utica shale (Smith, 2009). This depth corresponds approximately with the base of the organic-rich section of the Utica shale.

5.2.1 Total Organic Carbon

Measurements of TOC in the Utica shale are sparse. Where reported, TOC has been measured at over 3% by weight (Martin, 2005). Nyahay et al. (2007) compiled measurements of TOC for core and outcrop samples. TOC in the lower Indian Castle, Flat Creek, and Dolgeville Members generally ranges from 0.5 to 3%. TOC in the upper Indian Castle Member is generally below

0.5%. TOC as high as 3.0% in eastern New York and 15% in Ontario and Quebec were also reported (NYSERDA, 2005).

The New York State Museum Reservoir Characterization Group evaluated cuttings from the Utica shale wells in New York State and reported up to 3% TOC (Smith & Leone, 2009). Jarvie et al. (2007) showed that analyses from cutting samples may underestimate by approximately half; therefore, the TOC may be as high as 6%. Figure 5-6 shows the combined total thickness of the organic-rich (greater than 1%, based on cuttings analysis) members of the Utica Shale. As shown on Figure 5-6, the organic-rich Utica shale ranges from less than 50 feet thick in north-central New York and increases eastward to more than 700 feet thick.

5.2.2 Thermal Maturity and Fairways

Nyahay, et al. (2007) presented an assessment of gas potential in the Marcellus and Utica shales. The assessment was based on an evaluation of geochemical data from core and outcrop samples using methods applied to other shale gas plays, such as the Barnett shale in Texas. A gas production “fairway”, which is a portion of the shale most likely to produce gas based on the evaluation, was presented. Based on the available, limited data, Nyahay et al. (2007) concluded that most of the Utica shale is supermature and that the Utica shale fairway is best outlined by the Flat Creek Member where the TOC and thickness are greatest. This area extends eastward from a northeast-southwest line connecting Montgomery to Steuben Counties (Figure 5-7). The fairway shown on Figure 5-7 correlates approximately with the area where the organic-rich portion of the Utica shale is greater than 100 feet thick shown on Figure 5-6 (Smith 2009). The fairway is that portion of the formation that has the potential to produce gas based on specific geologic and geochemical criteria; however, other factors, such as formation depth, make only portions of the fairway favorable for drilling. Operators consider a variety of these factors, besides the extent of the fairway, when making a decision on where to drill for natural gas.

The results of the 2007 evaluation are consistent with an earlier report by Weary et al. (2000) that presented an evaluation of thermal maturity based on patterns of thermal alteration of conodont microfossils across New York State. The data presented show that the thermal maturity of much of the Utica shale in New York is within the dry natural gas generation and preservation range and generally increases from northwest to southeast.

5.2.3 Potential for Gas Production

The Utica shale historically has been considered the source rock for the more permeable conventional gas resources. Fresh samples containing residual kerogen and other petroleum residuals reportedly have been ignited and can produce an oily sheen when placed in water (Martin, 2005). Significant gas shows have been reported while drilling through the Utica shale in eastern and central New York (NYSERDA, 2002).

No Utica shale gas production was reported to DEC in 2009 (NYSDEC database, 2009). Vertical test wells completed in the Utica in the St. Lawrence Lowlands of Quebec have produced up to one million cubic feet per day (MMcf/d) of natural gas, and horizontal test wells are planned for 2009 (June, 2009).

5.3 Marcellus Formation

The Marcellus Formation is a Middle Devonian-aged member of the Hamilton Group that extends across most of the Appalachian Plateau from New York south to Tennessee. The Marcellus Formation consists of black and dark gray shales, siltstones, and limestones. The Marcellus Formation lies between the Onondaga limestone and the overlying Stafford-Mottville limestones of the Skaneateles Formation (VerStraeten, 2007; Gowan et al., 2006; and Rickard, 1989) and ranges in thickness from less than 25 feet in Cattaraugus County to over 1,800 feet along the Catskill front (Rickard, 1989). The informal name “Marcellus shale” is used interchangeably with the formal name “Marcellus Formation.” The discussion contained herein uses the name Marcellus shale to refer to the black shale in the lower part of the Hamilton Group.

The Marcellus shale covers an area of approximately 18,700 square miles in New York (Figure 5-8), is bounded approximately by US Route 20 to the north and interstate 87 and the Hudson River to the east, and extends to the Pennsylvania border. The Marcellus is exposed in outcrops to the north and east and at depths of more than 5,000 feet in the southern tier (Figure 5-8).

The Marcellus shale in New York State consists of three primary members (Rickard, 1989; VerStraeten, 2007; Nyahay et al., 2007). The oldest (lower-most) member of the Marcellus is the Union Springs shale which is laterally continuous with the Bakoven shale in the eastern part of the state. The Union Springs (and Bakoven shale) are bounded below by the Onondaga and above by the Cherry Valley limestone in the west and the correlative Stony Hollow Member in the East. The upper-most member of the Marcellus shale is the Oatka Creek shale (west) and the correlative Cardiff-Chittenango shales (east). The members of primary interest with respect to gas production are the Union Springs and lower-most portions of the Oatka Creek shale (Nyahay et al, 2007; Smith & Leone, 2009). The cumulative thickness of the organic-rich layers ranges from less than 25 feet in western New York to over 300 feet in the east (Figure 5-9).

Gamma ray logs indicate that the Marcellus shale has a slightly radioactive signature on gamma ray geophysical logs, consistent with typical black shales. Concentrations of uranium ranging from 5 to 100 parts per million have been reported in Devonian gas shales (Charpentier et al., 1982).

5.3.1 Total Organic Carbon

Figure 5-10 shows the aerial distribution of total organic carbon (TOC) in the Marcellus shale based on the analysis of drill cuttings sample data (Smith & Leone, 2009). TOC generally ranges between 2.5 and 5.5 percent and is greatest in the central portion of the state. Ranges of TOC values in the Marcellus were compiled and reported between 3 to 12% (Arthur et al., 2008) and 1 to 10.1% (Zaengle, 2009)

5.3.2 Thermal Maturity and Fairways

Vitrinite reflectance is a measure of the maturity of organic matter in rock with respect to whether it has produced hydrocarbons and is reported in percent reflection (%R_o). Values of 1.5 to 3.0% R_o are considered to correspond to the "gas window," though the upper value of the window can vary depending on formation and kerogen type characteristics.

VanTyne (1993) presented vitrinite reflection data from nine wells in the Marcellus shale in Western New York. The values ranged from 1.18 % R_o to 1.65 % R_o, with an average of 1.39 %R_o. The vitrinite reflectance values generally increase eastward. Nyahay et al (2007) and Smith & Leone (2009) presented vitrinite reflectance data for the Marcellus shale in New York (Figure 5-11) based on samples compiled by the New York State Museum Reservoir Characterization Group. The values ranged from less than 1.5 % R_o in western New York to over 3 % R_o in eastern New York.

Nyahay et al. (2007) presented an assessment of gas potential in the Marcellus shale that was based on an evaluation of geochemical data from rock core and outcrop samples using methods applied to other shale gas plays, such as the Barnett shale in Texas. The gas productive fairway was identified based on the evaluation and represents the portion of the Marcellus shale most likely to produce gas. The Marcellus fairway is similar to the Utica Shale fairway and is shown on Figure 5-12. The fairway is that portion of the formation that has the potential to produce gas based on specific geologic and geochemical criteria; however, other factors, such as formation depth, make only portions of the fairway favorable for drilling. Operators consider a variety of these factors, besides the extent of the fairway, when making a decision on where to drill for natural gas. Variation in the actual production is evidenced by Marcellus shale wells outside the fairway that have produced gas and wells within the fairway that have been reported dry.

5.3.3 Potential for Gas Production

Gas has been produced from the Marcellus since 1880 when the first well was completed in the Naples field in Ontario County. The Naples field produced 32 MMcf during its productive life and nearly all shale gas discoveries in New York since then have been in the Marcellus shale (NYSERDA, 2002). All gas wells completed in the Marcellus shale to date are vertical wells (NYSDEC, 2009). Figure 5-13 shows the location of shale gas wells in New York State completed in the Marcellus.

The NYSDEC's summary production database includes reported natural gas production for the years 1967 through 1999. Approximately 544 MMcf of gas was produced from wells completed in the Marcellus shale during this period (NYSDEC, 2009). In 2008, the most recent reporting year available, a total of 64.1 MMcf of gas was produced from 15 Marcellus shale wells in Livingston, Steuben, Schuyler, Chemung, and Allegany Counties.

Volumes of in-place natural gas resources have been estimated for the entire Appalachian Basin. Charpentier et al. (1982) estimated a total in-place resource of 844.2 trillion cubic feet (tcf) in all Devonian shales, which includes the Marcellus shale. Approximately 164.1 tcf, or 19%, of the total is from Devonian shales in New York State. NYSERDA estimates that approximately 15% of the total Devonian shale gas resource of the Appalachian Basin lies beneath New York State.

Engelder and Lash (2008) recently estimated an in-place resource of 500 tcf in the Marcellus shale beneath New York, Pennsylvania, West Virginia, and Maryland. Other natural gas plays, such as the Barnett shale, typically produce more than 10% of the in-place resource; therefore, the potential resource over time from Marcellus shale in the four state region including New York is approximately 50 tcf. A 15% to 19% portion of 50 tcf translates to a potential resource of approximately 7.5 to 9.5 tcf of gas over time in the Marcellus shale in New York State.

6.0 WELL SITE OPERATIONS

The operations associated with drilling and hydrofracturing a gas well have certain unavoidable environmental impacts that are related to the area needed to complete the work. These impacts are minimized by careful planning and implementing various control measures. This section evaluates the impacts associated with well site operations as those impacts related to soil, geology, surface water, chemistry, and material handling. Well site operations include siting, drilling, completion, stimulation, reclamation, production, maintenance, plugging and abandonment of a well. This section evaluates whether there are incremental impacts from these activities for an unconventional (horizontal well) drilled into shale and developed using high-volume hydraulic fracturing compared with drilling a conventional (vertical) well where high-volume hydraulic hydrofractuing is not used. This section further evaluates whether the potential impacts associated with horizontal well drilling in shale where high-volume hydraulic fracturing is used are sufficiently addressed by the 1992 GEIS. A description of the activities associated with each of these issues is provided in the following sections followed by a discussion and analysis.

6.1 Incremental Impacts from Horizontal Well Drilling and High-Volume Hydraulic Fracturing

Many aspects of horizontal well drilling using high-volume hydraulic fracturing operations are similar to the operations for a vertical well where high-volume hydraulic fracturing is not used. Those operations that are similar are addressed in the 1992 GEIS. The aspects that are different primarily are the result of the larger scale of horizontal well drilling and high-volume hydraulic fracturing operations. Specifically, these well operations occur over a longer period of time due to the location of multiple wells at a single site; require a larger well pad from which to drill multiple wells; produce a larger volume of drill cuttings; and use larger quantities of water and fluids, primarily for hydrofracturing.

6.2 Impacts Associated with Larger Well Pads

The primary difference in site preparation for a vertical well versus a horizontal well where high-volume hydraulic fracturing is implemented is that more land initially is disturbed to build a larger well pad. The larger well pad is necessary because up to eight wells may be drilled from the same pad and to accommodate the amount of equipment and materials required to perform high-volume hydraulic fracturing. The horizontal wells also require larger drilling equipment, more materials, and larger pits for drilling the longer bores for the horizontal sections. A typical well pad for a vertical well requires approximately 2 acres. The well pads for horizontal wells using high-volume hydraulic fracturing are approximately 3 to 6 acres. This size range depends partly on the number of wells, which is expected to range between 6 and 8 per pad for horizontal wells, but primarily is a function of the short-term presence of equipment and materials needed to support the high-volume hydraulic fracturing process. These larger initial well pads will be reclaimed and reduced to approximately 2 acres after the wells enter the production phase. There is a greater potential for stormwater impacts from a larger well pad during the production phase, compared with a smaller well pad for a single vertical well.

The overall impacts from horizontal drilling and high-volume hydraulic fracturing are likely to be less when a larger land area is considered. An area up to 640 acres is the spacing unit for horizontal shale gas wells with written commitment to drill infill wells with all horizontal infill wells to be drilled from a common pad within 3 years of the first drilled well, as established by ECL 23-0501. A spacing of 40 acres per well for vertical shale gas wells would result in 32 acres of well pad disturbance (2 acres per well) to develop an area of 640 acres, plus the additional acreage to construct access roads to each of the 16 well pads. A single well pad with 6 to 8 horizontal shale gas wells could access all 640acres. This translates to 3 to 6 acres of well pad disturbance, plus a single access road, compared with 32 acres of well pad disturbance plus access roads to develop the same area using vertical shale gas wells. There clearly is a much smaller total area of land disturbance associated with horizontal wells for shale gas development.

6.3 Impacts Associated with Duration of Disturbance

Operations at the site of a vertical well are performed sequentially until the well is completed and producing natural gas. In contrast, operations at a multi-horizontal well pad may entail drilling multiple wells, possibly simultaneously, which may or may not be drilled, hydrofractured, and completed in succession. It is possible that one or two wells may be completed initially during the exploration phase at a horizontal, multi-well drilling site followed by a hiatus of 1 ½ to 2 years before the remaining wells are drilled and stimulated. Thus, the duration of activity at a horizontal, multi-well drilling site may be approximately 3 years with periods of inactivity within that timeframe. More intense activity would be expected during the production phase of development when wells may be drilled and hydrofractured without a significant hiatus in activity.

Preparation of a well pad may take approximately five to 30 days, depending on the size and the anticipated complexity of operations. The duration to drill a horizontal gas well is approximately 20 to 30 days (Chesapeake, 2009 and Fortuna 2009). The lag between well completion and hydrofracturing at a horizontal multi-well drilling site may be as much as 2 to 3 months. Three to five weeks of that duration is needed to bring sufficient water to the site for hydrofracturing and the hydrofracturing operation takes approximately two to five days for a single horizontal well (Chesapeake, 2009, personal communication). Subsequent flowback and testing may last approximately 30 to 60 days (Fortuna, 2009, personal communication and Chesapeake, 2009, personal communication).

Certain efficiencies may be achieved by drilling some or all wells on the same well pad in succession. The drilling process may involve drilling the upper, vertical portion of the well with one type of drilling rig, and the lower, horizontal portion of the well with a different, larger drilling rig. This simultaneous drilling method can reduce the duration necessary to complete the drilling phase. For example, six wells may be drilled in approximately 70 to 100 days if drilled in succession using multiple drilling rigs. (Fortuna, 2009, personal communication). Similarly, fracing six wells sequentially would be more efficient, primarily because the large amount of required equipment would not need to be demobilized and remobilized for each well's hydrofracturing operation. Nonetheless, operators may not drill all of the wells at a single well pad at once for a variety of other factors, particularly during the exploration phase.

6.4 Impacts Associated with Drill Cuttings

Drill cuttings are produced when drilling both vertical and horizontal wells. A vertical well consists of a single vertical hole drilled to the target gas-producing depth. A horizontal well consists of drilling an upper vertical borehole and diverting the borehole to a horizontal orientation for a distance of between 2,000 and 5,000 thousand feet, through the target gas-producing formation. For shale gas development, operators typically will drill multiple horizontal wells from a single well pad. Drilling multiple horizontal wells from the same well pad produces a greater total volume of drill cuttings at the site because each horizontal well penetrates a greater linear distance of rock than a vertical well, and multiple wells will be drilled at a single location.

Cuttings from the drilling process may be managed within a closed loop system or discharged to a lined drilling (reserve) pit (Fortuna, 2009). Operators that use a reserve pit likely will use a single pit for multiple wells, if possible, as a matter of efficiency. Typical methods of disposing drill cuttings include removing all free fluids and burying onsite; land farming; disposal at a landfill; or deep well injection with the drilling mud (Chesapeake, 2009). Landfarming of drill cuttings previously has not been allowed in New York. Deep well injection has not been practiced in NY and would require a permit from the US Environmental Protection Agency (Underground Injection Control permit) and New York State SPDES permit.

The 1992 GEIS requires that pits must be closed, and site reclamation proceed within 45 days after the cessation of drilling operations. These requirements apply to drilling reserve pits that retain drill cuttings and may create logistical difficulties and inefficiencies if an operator completes only one or two wells at a multi-well pad and defers drilling the remaining wells to a later date. Adoption of temporary pit closure measures may provide an alternative that does not require the pit to be closed prematurely, while addressing maintenance and safety issues associated with a dormant pit.

6.5 Fluid Handling Controls

The fluids used or generated during the drilling and hydrofracturing process include freshwater, drilling mud, flowback water, and produced water. Fluids are handled and controlled on site using steel tanks and/or lined pits, in accordance with applicable regulations. Fresh water, or fresh water blended with recycled flowback water, or recycled flowback water, is the greatest volume of fluid to be used or managed to complete an unconventional well. Some fresh water is used in the drilling process for both the air drilling of the vertical portion of the well and for the mud needed to drill the horizontal portion of the well. A much larger volume of water is needed during the hydrofracturing process. Approximately 300,000 to 500,000 gallons of water are used to hydrofracture a single stage in a horizontal well (Fortuna, 2009, personal communication and Chesapeake, 2009, personal communication). The number of stages at each well ranges between 7 and 10. The actual volume used for hydrofracturing may vary from well to well and from site to site; however, a total of two to four million gallons of fresh water may be used in a single horizontal well and between 16 and 32 million gallons to drill and hydrofracture up to eight horizontal wells at a pad. Operators anticipate recycling and reusing flowback water for use at subsequent wells after appropriate treatment and/or blending with fresh water. Reuse of flowback water will reduce the amount of fresh water source withdrawal.

It is difficult to quantify the amount of flowback water that may be produced because of the limited number of wells drilled to completion in the Marcellus to date. Early reports from wells drilled into the Marcellus in Pennsylvania indicate that flowback volumes are in the range of 10 to 25 percent of the injected fluid (Fortuna, 2009, personal communication).

Drilling mud may be used to drill the horizontal section of an unconventional well. The mud is processed though an open-top mud tank/mixing system that consists of shale shakers, settling tanks, and mixing tanks. The typical volume of drilling mud is approximately 800 to 1,000 barrels which is recirculated during the drilling process (Chesapeake, 2009). Fresh water is added as necessary during drilling to maintain the necessary volume of mud. Drilling mud is reconditioned to the extent practicable for use in multiple wells and often is disposed in permitted injection wells in other states. Disposing drilling mud by deep well injection has not previously been a practice in New York. Deep well injection would require a permit from the US Environmental Protection Agency (Underground Injection Control permit) and a New York State SPDES permit.

Produced water is water that seeps out of the formation with the gas during the gas production phase. The production phase occurs after the frac flowback phase. Produced water can be retained in steel frac tanks, or permanent plastic, fiberglass or steel tanks. Storing produced water in lined pits/impoundments is not allowed in New York State. Permanent tanks typically are installed to retain produced water, once a gas well is put online and the volume of water production is relatively steady. The produced water is periodically removed from the site for disposal or processing.

6.6 Discussion of Well Site Operations

The activities associated with the preparation of a well pad are similar for both vertical wells and multi-horizontal well pads where high volume hydrofracturing will be used. Site preparation activities consist primarily of clearing and leveling an area of adequate size and preparing the surface to support movement of heavy equipment. The ground surface preparation typically involves placing a layer of crushed stone over geotextile fabric for the well pad and roads. Site preparation also includes constructing an access road, establishing erosion and sediment control structures around the site, and constructing pits for retention of drilling fluid and possibly fresh water. The 1992 GEIS contemplates well pads of approximately 1 acre in size and short-term site disturbances for conventional vertical drilling operations. The larger pads and longer durations of site activities have greater potential from storm water runoff impacts. The 1992 GEIS states that erosion control measures are necessary if an access road is subject to erosion and in conjunction with a stream disturbance permit, if necessary. An erosion and sediment control program is required by the 1992 GEIS if drilling occurs within the watershed of a drinking water reservoir. The DRBC and SRBC also require controls within the respective river basins. Authorization to discharge stormwater will be required under the NYSDEC SPDES General Permit, which also requires preparation of a Stormwater Pollution Prevention Plan

(SWPPP). Additional erosion and sediment control measures may be required by the SWPPP, based on the size of the well pads and the duration of disturbance for multiple, horizontal well operations.

The duration of disturbance for a multiple, horizontal well pad site is greater than that for a single vertical well, particularly if all wells permitted for a multi-well pad are completed. The potential impacts associated with a multiple horizontal well drilling site will occur over a longer period of time. Mitigative measures will help to minimize those impacts; however, the increased duration of operations associated with completing all wells on a multi-well pad is unavoidable. The extended duration of multiple horizontal well drilling activities and associated high volume hydrofracturing should be considered and acknowledged in the SGEIS.

The total volume of drill cuttings produced from drilling a horizontal well is greater than that for a conventional, vertical well. The potential impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations is associated with retention of the cuttings during drilling and disposal of the cuttings at the conclusion of drilling. Specific measures are outlined in the 1992 GEIS for retention and disposal of cuttings. Most of these measures are applicable to the greater volume of cuttings that are produced during multiple horizontal well drilling operations. The geotechnical stability and bearing capacity of buried cuttings, if left in a common pit, may need to be considered in the SGEIS because of the greater volume of drill cuttings produced by multiple horizontal wells.

Fluid handling controls at a horizontal well drilling site include the use of lined pits/impoundments, temporary steel tanks, and permanent plastic, fiberglass or steel tanks. These methods of fluid handling and control are applicable regardless of the volume of fluids, which is the primary difference between conventional and unconventional drilling operations. The 1992 GEIS addresses the use of lined pits/impoundments, temporary tanks, and permanent tanks for handling and controlling fluids. The 1992 GEIS also appropriately references other regulations that apply in the case of accidental spillage or release of certain fluids; however, the use of frac tanks may be the preferred and recommended method for temporary onsite storage of flowback water as opposed to storing the water in lined pits or impoundments. Some operators have expressed interest in possible use of adequately lined pits for temporary storage. Nonetheless, the frac tanks provide a closed system of storage which essentially removes concerns of potential release of flowback water to the environment. The use of frac tanks for storage of flowback would not affect logistics if operators already have on site a large number of tanks used during the hydrofracturing process. Requiring storage of flowback water in frac tanks may create greater logistical difficulties if water for hydrofracturing is brought to the well pad via a temporary pipeline from a centralized impoundment. In that case, it may be possible or advisable to pump flowback water from the drill site to the centralized impoundment via the pipeline.

7.0 SEISMICITY AND HIGH-VOLUME HYDRAULIC FRACTURING

Economic development of natural gas from low permeability formations requires the target formation to be hydraulically fractured (hydrofractured) to increase the rock permeability and expose more rock surface to release the gas trapped within the rock. The hydrofracturing process fractures the rock by controlled application of hydraulic pressure in the wellbore. The direction and length of the fractures are managed by carefully controlling the applied pressure during the hydrofracturing process.

The release of energy during hydrofracturing produces seismic pressure waves in the subsurface. Microseismic monitoring commonly is performed to evaluate the progress of hydrofracturing and adjust the process, if necessary, to limit the direction and length of the induced fractures. The following sections present background seismic information for New York, describe the hydrofracturing process, and discuss the concerns associated with the seismic events produced during hydrofracturing.

7.1 Seismicity in New York State

7.1.1 Background

The term “earthquake” is used to describe any event that is the result of a sudden release of energy in the earth's crust that generates seismic waves. Many earthquakes are too minor to be detected without sensitive equipment. Hydrofracturing releases energy during the fracturing process at a level substantially below that of small, naturally occurring, earthquakes. Large earthquakes result in ground shaking and sometimes displacing the ground surface. Earthquakes are caused mainly by movement along geological faults, but also may result from volcanic activity and landslides. An earthquake's point of origin is called its focus or hypocenter. The term epicenter refers to the point at the ground surface directly above the hypocenter.

Induced seismicity refers to seismic events triggered by human activity such as mine blasts, nuclear experiments, and fluid injection, including hydrofracturing (Geosciences Australia, 2008). Induced seismic waves (seismic refraction and seismic reflection) also are a common tool used in geophysical surveys for geologic exploration. The surveys are used to investigate the subsurface for a wide range of purposes including landfill siting; foundations for roads, bridges, dams and buildings; oil and gas exploration; mineral prospecting; and building foundations. Methods of inducing seismic waves range from manually striking the ground with weight to setting off controlled blasts.

Geologic faults are fractures along which rocks on opposing sides have been displaced relative to each other. The amount of displacement may be small (centimeters) or large (kilometers). Geologic faults are prevalent and typically are active along tectonic plate boundaries. One of the most well known plate boundary faults is the San Andreas fault zone in California. Faults also occur across the rest of the U.S., including mid-continent and non-plate boundary areas, such as the New Madrid fault zone in the Mississippi Valley, or the Ramapo fault system in southeastern New York and eastern Pennsylvania.

Figure 7-1 shows the locations of faults and other structures that may indicate the presence of buried faults in New York State (Isachsen and McKendree, 1977). There is a high concentration of structures in eastern New York along the Taconic Mountains and the Champlain Valley that resulted from the intense thrusting and continental collisions during the Taconic and Alleghenian orogenies that occurred 350 to 500 million years ago (Isachen et al., 1991). There also is a high concentration of faults along the Hudson River Valley. More recent faults in northern New York were formed as a result of the uplift of the Adirondack Mountains approximately 5 to 50 million years ago.

7.1.2 Seismic Risk Zones

The USGS Earthquake Hazard Program has produced the National Hazard Maps showing the distribution of earthquake shaking levels that have a certain probability of occurring in the United States. The maps were created by incorporating geologic, geodetic, historic seismic data, and information on earthquake rates and associated ground shaking. These maps are used by others to develop and update building codes and to establish construction requirements for public safety.

New York State is not associated with a major fault along a tectonic boundary like the San Andreas, but seismic events are common in New York. Figure 7-2 shows the seismic hazard map for New York State (USGS, 2008a). The map shows levels of horizontal shaking, in terms of percent of the gravitational acceleration constant (%g) that is associated with a 2 in 100 (2%) probability of occurring during a 50 year period (USGS, 2008b). Much of the Marcellus and Utica shales underlie portions of the state with the lowest seismic hazard class rating in New York (2 % probability of exceeding 4 to 8 %g in a fifty year period). The areas around New York City, Buffalo, and northern-most New York have a moderate to high seismic hazard class ratings (2% probability of exceeding 12 to 40 %g in a fifty year period).

7.1.3 Seismic Damage – Modified Mercalli Intensity Scale

There are several scales by which the magnitude and the intensity of a seismic event are reported. The Richter magnitude scale was developed in 1935 to measure of the amount of energy released during an earthquake. The moment magnitude scale (MMS) was developed in the 1970s to address shortcomings of the Richter scale, which does not accurately calculate the magnitude of earthquakes that are large (greater than 7) or distant (measured at a distance greater than 250 miles away). Both scales report approximately the same magnitude for earthquakes less than a magnitude of 7 and both scales are logarithmic-based; therefore, an increase of one magnitude unit corresponds to a 1,000-fold increase in the amount of energy released.

The MMS measures the size of a seismic event based on the amount of energy released. Moment is a representative measure of seismic strength for all sizes of events and is independent of recording instrumentation or location. Unlike the Richter scale, the MMS has no limits to the possible measurable magnitudes, and the MMS relates the moments to the Richter scale for continuity. The MMS also can represent microseisms (very small seismicity) with negative numbers.

The Modified Mercalli (MM) Intensity Scale was developed in 1931 to report the intensity of an earthquake. The Mercalli scale is an arbitrary ranking based on observed effects and not on a mathematical formula. This scale uses a series of 12 increasing levels of intensity that range from imperceptible shaking to catastrophic destruction, as summarized on Table 7.1. Table 7.1 compares the MM intensity scale to magnitudes of the MMS, based on typical events as measured near the epicenter of a seismic event. There is no direct conversion between the intensity and magnitude scales because earthquakes of similar magnitudes can cause varying levels of observed intensities depending on factors such location, rock type, and depth.

7.1.4 Seismic Events

Table 7.2 summarizes the recorded seismic events in New York State by county between December 1970 and July 2009 (LCSN, 2009). There were a total of 813 seismic events recorded in New York State during that period. The magnitudes of 24 of the 813 events were equal to or greater than 3.0. Magnitude 3 or lower earthquakes are mostly imperceptible and are usually detectable only with sensitive equipment. The largest seismic event during the period 1970 through 2009 is a 5.3 magnitude earthquake that occurred on April 20, 2002, near Plattsburg, Clinton County (LCSN, 2009). Damaging earthquakes have been recorded since Europeans settled New York in the 1600s. The largest earthquake ever measured and recorded in New York State was a magnitude 5.8 event that occurred on September 5, 1944, near Massena, New York (USGS, 2009a).

Figure 7-3 shows the distribution of recorded seismic events in New York State. The majority of the events occur in the Adirondack Mountains and along the New York-Quebec border. A total of 180 of the 813 seismic events shown on Table 7.2 and Figure 7-3 during a period of 39 years (1970–2009) occurred in the area of New York that is underlain by the Marcellus and/or the Utica shales. The magnitude of 171 of the 180 events was less than 3.0. The distribution of seismic events on Figure 7-3 is consistent with the distribution of fault structures (Figure 7-1) and the seismic hazard risk map (Figure 7-2).

Some of the seismic events shown on Figure 7-3 are known or suspected to be triggered by human activity. The 3.5 magnitude event recorded on March 12, 1994, in Livingston County is suspected to be the result of the collapse associated with the Retsof salt mine failure in Cuylerville, New York (Gowan, 2000). The 3.2 magnitude event recorded on February 3, 2001, was coincident with, and is suspected to have been triggered by, test injections for brine disposal at the New Avoca Natural Gas Storage (NANGS) facility in Steuben County. The cause of the event likely was the result of an extended period of fluid injection near an existing fault (Pratt, 2001) for the purposes of siting a deep injection well. The injection for the NANGS project occurred numerous times with injection periods lasting 6 to 28 days and is substantially different than the short-duration, controlled injection used for hydrofracturing.

One additional incident that is suspected to be related to human activity occurred in 1971 and is related to the solution mining of brine near Dale, Wyoming County, New York (Dale Brine Field). The Texas Brine Corporation operated a system of wells that consisted of a central, high pressure injection well (No. 11) and four peripheral brine recovery wells. The central injection well was hydrofractured in July 1971 without incident.

The well system was located in the immediate vicinity of the known, mapped, Clarendon-Linden fault zone which is oriented north-south, and extends south of Lake Ontario in Orleans, Genesee, Wyoming, and the northern end of Allegany Counties, New York. The Clarendon-Linden fault zone is not of the same magnitude, scale, or character as the plate boundary fault systems, but nonetheless has been the source of relatively small to moderate quakes in western New York (MCEER, 2009; and Fletcher and Sykes, 1977).

Fluids for solution mining were injected at well No. 11 from August 3 through October 8, and from October 16 through November 9, 1971. Injections were ceased on November 9, 1971 due to an increase in seismic activity in the area of the injection wells. A decrease in seismic activity occurred when the injections ceased. The tremors attributed to the injections reportedly were felt by residents in the immediate area.

Evaluation of the seismic activity associated with the Dale Brine Field was performed and published by researchers from the Lamont-Doherty Geological Observatory (Fletcher and Sykes, 1977). The evaluation concluded that fluids injected during solution mining activity were able to reach the Clarendon-Linden fault and that the increase of pore fluid pressure along the fault caused an increase in seismic activity. The research states that “the largest earthquake … that appears to be associated with the brine field…” was 1.4 in magnitude. In comparison, the magnitude of the largest natural quake along the Clarendon-Linden fault system through 1977 was magnitude 2.7, measured in 1973. Similar solution mining well operations in later years located further from the fault system than the Dale Brine Field wells did not create an increase in seismic activity.

7.1.5 Monitoring Systems in New York

Seismicity in New York is monitored by both the US Geological Survey and the Lamont-Doherty Cooperative Seismographic Network (LCSN). The LCSN is part of the USGS’s Advanced National Seismic System (ANSS) which provides current information on seismic events across the country. Other ANSS stations are located in Binghamton and Lake Ozonia, New York. The New York State Museum also operates a seismic monitoring station in the Cultural Education Center in Albany, New York.

As part of the AANS, the LCSN monitors earthquakes that occur primarily in the northeastern United States and coordinates and manages data from 40 seismographic stations in seven states, including Connecticut, Delaware, Maryland, New Jersey, New York, Pennsylvania, and Vermont (LCSN, 2009). Member organizations that operate LCSN stations include two secondary schools, two environmental research and education centers, three state geological surveys, a museum dedicated to Earth system history, two public places (Central Park, NYC, and Howe Caverns, Cobleskill), three two-year colleges, and 15 four-year universities (LCSN, 2009).

7.2 Hydraulic Fracturing-Induced Seismicity

Seismic events that occur as a result of injecting fluids into the ground are termed “induced”. There are two types of induced seismic events that may be triggered as a result of hydraulic fracturing. The first is energy released by the physical process of fracturing the rock which creates microseismic events that are detectable only with very sensitive monitoring equipment. Information collected during the microseismic events is used to evaluate the extent of fracturing and to guide the hydrofracturing process. This type of microseismic event is a normal part of the hydrofracturing process used in the development of both horizontal and vertical oil and gas wells, and by the water well industry.

The second type of induced seismicity is fluid injection of any kind, including hydrofracturing, which can trigger seismic events ranging from imperceptible microseismic, to small-scale, “felt” events, if the injected fluid reaches an existing geologic fault. A “felt” seismic event is when earth movement associated with the event is discernable by humans at the ground surface. Hydrofracturing produces microseismic events, but different injection processes, such as waste disposal injection or long term injection for enhanced geothermal, may induce events that can be felt, as discussed in the following section. Induced seismic events can be reduced by engineering design and by avoiding existing fault zones.

7.2.1 Background

Hydraulic fracturing consists of injecting fluid into a wellbore at a pressure sufficient to fracture the rock within a designed distance from the wellbore. Other processes where fluid is injected into the ground include deep well fluid disposal, fracturing for enhanced geothermal wells, solution mining and hydrofracturing to improve the yield of a water supply well. The similar aspect of these methods is that fluid is injected into the ground to fracture the rock; however, each method also has distinct and important differences.

There are ongoing and past studies that have investigated small, felt, seismic events that may have been induced by injection of fluids in deep disposal wells. These small seismic events are not the same as the microseismic events triggered by hydraulic fracturing that can only be detected with the most sensitive monitoring equipment. The processes that induce seismicity in both cases are very different.

Deep well injection is a disposal technology which involves liquid waste being pumped under moderate to high pressure, several thousand feet into the subsurface, into highly saline, permeable injection zones that are confined by more shallow, impermeable strata (FRTR, August 12, 2009). The goal of deep well injection is to store the liquids in the confined formation(s) permanently.

Carbon sequestration also a type of deep well injection, but the carbon dioxide emissions from a large source are compressed to a near liquid state. Both carbon sequestration and liquid waste injection can induce seismic activity. Induced seismic events caused by deep well fluid injection are typically less than a magnitude 3.0 and are too small to be felt or to cause damage. Rarely, fluid injection induces seismic events with moderate magnitudes, between 3.5 and 5.5, that can be felt and may cause damage. Most of these events have been investigated in detail and have been shown to be connected to circumstances that can be avoided through proper site selection (avoiding fault zones) and injection design (Foxall and Friedmann, 2008).

Hydraulic fracturing also has been used in association with enhanced geothermal wells to increase the permeability of the host rock. Enhanced geothermal wells are drilled to depths of many thousands of feet where water is injected and heated naturally by the earth. The rock at the target depth is fractured to allow a greater volume of water to be recirculated and heated. Recent geothermal drilling projects for commercial energy-producing geothermal projects have focused on hot, dry, rocks as the source of geothermal energy (Duffield, 2003). The geologic conditions and rock types for these geothermal projects are in contrast to the shallower sedimentary rocks targeted for natural gas development. The methods used to fracture the igneous rock for geothermal projects involve high pressure applied over a period of many days or weeks (Florentin 2007 and Geoscience Australia, 2009). These methods differ substantially from the lower pressures and short durations used for natural gas well hydrofracturing.

Hydraulic fracturing is a different process that involves injecting fluid under higher pressure for shorter periods than the pressure level maintained in a fluid disposal well for longer periods. A horizontal well is hydrofractured in stages so that the pressure is repeatedly increased and released over a short period of time necessary to fracture the rock. The subsurface pressures for hydraulic fracturing are sustained typically for one or two days to stimulate a single well, or for approximately two weeks at a multi-well pad. The seismic activity induced by hydraulic fracturing is only detectable at the surface by very sensitive equipment.

Avoiding pre-existing fault zones minimizes the possibility of triggering movement along a fault through hydraulic fracturing. It is important to avoid injecting fluids into known, significant, mapped faults when hydrofracturing. Generally, operators will avoid faults because they disrupt the pressure and stress field and the hydrofracturing process. The presence of faults also potentially reduces the optimal recovery of gas and the economic viability of a well or wells.

Injecting fluid into the subsurface can trigger shear slip on bedding planes or natural fractures resulting in microseismic events. Fluid injection can temporarily increase the stress and pore pressure within a geologic formation. Tensile stresses are formed at each fracture tip, creating shear stress (Pinnacle; "FracSeis;" August 11, 2009) The increases in pressure and stress reduce the normal effective stress acting on existing fault, bedding, or fracture planes. Shear stress then overcomes frictional resistance along the planes, causing the slippage (Bou-Rabee and Nur, 2002). The way in which these microseismic events are generated is different than the way in which microseisms occur from the energy release when rock is fractured during hydrofracturing.

The amount of displacement along a plane that is caused by hydraulic fracturing determines the resultant microseism's amplitude. The energy of one of these events is several orders of magnitude less than that of the smallest earthquake that a human can feel (Pinnacle;

"Microseismic;" August 11, 2009). The smallest measurable seismic events are typically between 1.0 and 2.0 magnitude. In contrast, seismic events with magnitude 3.0 are typically large enough to be felt by people. Many induced microseisms have a negative value on the MMS. Pinnacle Technologies, Inc. has determined that the characteristic frequencies of microseisms are between 200 and 2,000 Hertz; these are high-frequency events relative to typical seismic data. These small magnitude events are monitored using extremely sensitive instruments that are positioned at the fracture depth in an offset wellbore or in the treatment well (Pinnacle; "Microseismic;" August 11, 2009). The microseisms from hydrofracturing can barely be measured at ground surface by the most sensitive instruments (Sharma, personal communication, August 7, 2009).

There are no seismic monitoring protocols or criteria established by regulatory agencies that are specific to high volume hydraulic fracturing. Nonetheless, operators monitor the hydrofracturing process to optimize the results for successful gas recovery. It is in the operator's best interest to closely control the hydrofracturing process to ensure that fractures are propagated in the desired direction and distance and to minimize the materials and costs associated with the process.

The routine microseismic monitoring that is performed during hydraulic fracturing serves to evaluate, guide, and control the process and is important in optimizing well treatments. Multiple receivers on a wireline array are placed in one or more offset borings (new, unperforated well(s) or older well(s) with production isolated) or in the treatment well to detect microseisms and to monitor the hydraulic fracturing process. The microseism locations are triangulated using the arrival times of the various p- and s-waves with the receivers in several wells, and using the formation velocities to determine the location of the microseisms. A multi-level vertical array of receivers is used if only one offset observation well is available. The induced fracture is interpreted to lie within the envelope of mapped microseisms (Pinnacle; "FracSeis;" August 11, 2009).

Data requirements for seismic monitoring of a hydraulic fracturing treatment include formation velocities (from a dipole sonic log or cross-well tomogram), well surface and deviation surveys, and a source shot in the treatment well to check receiver orientations, formation velocities and test capabilities. Receiver spacing is selected so that the total aperture of the array is about half the distance between the two wells. At least one receiver should be in the treatment zone, with another located above and one below this zone. Maximum observation distances for microseisms should be within approximately 2500 ft of the treatment well; the distance is dependent upon formation properties and background noise level (Pinnacle; “FracSeis;” August 11, 2009).

7.2.2 Recent Investigations and Studies

Hydraulic fracturing has been used by oil and gas companies to stimulate production of vertical wells in New York State since the 1950s. Despite this long history, there are no records of induced seismicity caused by hydraulic fracturing in New York State. The only induced seismicity studies that have taken place in New York State are related to seismicity suspected to have been caused by waste fluid disposal by injection and a mine collapse, as identified in section 7.1.4. The seismic events induced at the Dale Brine Field (Section 7.1.4) were the result of the injection of fluids for extended periods of time at high pressure for the purpose of salt solution mining. This process is significantly different from the hydrofracturing process that will be undertaken for developing the Marcellus and other low permeability shales in New York.

Gas producers in Texas have been using horizontal drilling and high-volume hydraulic fracturing to stimulate gas production in the Barnett Shale for the last decade. The Barnett is geologically similar to the Marcellus, but is found a greater depth. It is a deep shale with gas stored in unconnected pore spaces and absorbed to the shale matrix. High-volume hydraulic fracturing allows recovery of the gas from the Barnett to be economically feasible. The horizontal drilling and high-volume hydraulic fracturing methods used for the Barnett shale play are similar to those that would be used in New York State to develop the Marcellus, Utica, and other gas bearing shales.

Alpha contacted several researchers and geologists who are knowledgeable about seismic activity in New York and Texas, including:

- Mr. John Armbruster, Staff Associate, Lamont-Doherty Earth Observatory, Columbia University
- Dr. Cliff Frohlich, Associate Director of the Texas Institute for Geophysics, The University of Texas at Austin
- Dr. Won-Young Kim, Doherty Senior Research Scientist, Lamont-Doherty Earth Observatory, Columbia University
- Mr. Eric Potter, Associate Director of the Texas Bureau of Economic Geology, The University of Texas at Austin
- Mr. Leonardo Seeber, Doherty Senior Research Scientist, Lamont-Doherty Earth Observatory, Columbia University
- Dr. Mukul Sharma, Professor of Petroleum and Geosystems Engineering, The University of Texas at Austin
- Dr. Brian Stump, Albritton Professor, Southern Methodist University

None of these researchers have knowledge of any seismic events that could be explicitly related to hydraulic fracturing in a shale gas well. Mr. Eric Potter stated that approximately 12,500 wells in the Barnett play and several thousand wells in the East Texas Basin (which target tight gas sands) have been stimulated using hydraulic fracturing in the last decade, and there have been no documented connections between wells being fractured hydraulically and felt quakes (personal communication, August 9, 2009). Dr. Mukul Sharma confirmed that microseismic events associated with hydraulic fracturing can only be detected using very sensitive instruments (personal communication, August 7, 2009).

The Bureau of Geology, the University of Texas' Institute of Geophysics, and Southern Methodist University are planning to study earthquakes measured in the vicinity of the Dallas–Fort Worth (DFW) area, and Cleburne, Texas, that appear to be associated with salt water disposal wells, and oil and gas wells. The largest quakes in both areas were magnitudes of 3.3, and more than 100 earthquakes with magnitudes greater than 1.5 have been recorded in the DFW area in 2008 and 2009. There is considerable oil and gas drilling and deep brine disposal wells in the area and a small fault extends beneath the DFW area. Dr. Frohlich recently stated that "[i]t's always hard to attribute a cause to an earthquake with absolute certainty." Dr. Frohlich has two manuscripts in preparation with Southern Methodist University describing the analysis of the DFW activity and the relationship with gas production activities (personal communication, August 4 and 10, 2009). Neither of these manuscripts was available before this report was completed. Nonetheless, information posted online by Southern Methodist University (SMU, 2009) states that the research suggests that the earthquakes seem to have been caused by injections associated with a deep brine disposal well, and not with hydrofracturing operations.

7.2.3 Correlations between New York and Texas

The gas plays of interest, the Marcellus and Utica shales in New York and the Barnett shale in Texas, are relatively deep, low permeability, gas shales deposited during the Paleozoic Era. Horizontal drilling and high-volume hydraulic fracturing methods are required for successful, economical gas production. The Marcellus shale was deposited during the early Devonian, and the slightly younger Barnett was deposited during the late Mississippian. The depth of the Marcellus Shale in New York ranges from exposure at the ground surface in some locations in the northern Finger Lakes area to 7,000 feet or more below the ground surface at the Pennsylvania border in the Delaware River valley. The depth of the Utica shale in New York ranges from exposure at the ground surface along the southern Adirondacks to more than 10,000 feet along the New York Pennsylvania border.

Conditions for economic gas recovery likely are present only in portions of the Marcellus and Utica members, as described in Sections 5.2 and 5.3. The thickness of the Marcellus and Utica in New York ranges from less than 50 feet in the southwestern portion of the state to approximately 250 feet at the south-central border. The Barnett Shale is 5,000 to 8,000 feet below the ground surface and 100 to 500 feet thick (Halliburton; August 12, 2009). It is estimated that the entire Marcellus Shale may hold between 168 and 516 trillion cubic feet of gas; in contrast, the Barnett has in-place gas reserves of approximately 26.2 trillion cubic feet (USGS, 2009b) and covers approximately 4 million acres.

The only known induced seismicity associated with the stimulation of the Barnett wells are microseisms that are monitored with downhole transducers. These small-magnitude events triggered by the fluid pressure provide data to the operators to monitor and improve the fracturing operation and maximize gas production. The hydraulic fracturing and monitoring operations in the Barnett have provided operators with considerable experience with conditions similar to those that will be encountered in New York State. Based on the similarity of conditions, similar results are anticipated for New York State; that is, the microseismic events will be unfelt at the surface and no damage will result from the induced microseisms. Operators are likely to monitor the seismic activity in New York, as it is performed in Texas, to optimize the hydraulic fracturing methods and results.

7.2.4 Affects of Seismicity on Wellbore Integrity

Wells are designed to withstand deformation from seismic activity. The steel casings used in modern wells are flexible and are designed to deform to prevent rupture. The casings can withstand distortions much larger than those caused by earthquakes, except for those very close to an earthquake epicenter. The magnitude 6.8 earthquake event in 1983 that occurred in Coalinga, California, damaged only 14 of the 1,725 nearby active oilfield wells, and the energy released by this event was thousands of times greater than the microseismic events resulting from hydrofracturing. Earthquake-damaged wells can often be re-completed. Wells that cannot be repaired are plugged and abandoned (Foxall and Friedmann, 2008). Induced seismicity from hydrofracturing is of such small magnitude that it is not expected to have any effect on wellbore integrity.

7.3 Summary

The issues associated with seismicity related to hydraulic fracturing addressed herein include seismic events generated from the physical fracturing of the rock, and possible seismic events produced when fluids are injected into existing faults.

The possibility of fluids injected during hydrofracturing the Marcellus or Utica shales reaching a nearby fault and triggering a seismic event are remote for several reasons. The locations of major faults in New York have been mapped (Figure 7-1) and few major or seismically active faults exist within the fairways for the Marcellus and Utica shales. Similarly, the paucity of historic seismic events and the low seismic risk level in the fairways for these shales indicates that geologic conditions generally are stable in these areas. By definition, faults are planes or zones of broken or fractured rock in the subsurface. The geologic conditions associated with a fault generally are unfavorable for hydraulic fracturing and economical production of natural gas. As a result, operators typically endeavor to avoid faults for both practical and economic considerations. It is prudent for an applicant for a drilling permit to evaluate and identify known, significant, mapped, faults within the area of effect of hydrofracturing and to present such information in the drilling permit application. It is Alpha's opinion that an independent pre-drilling seismic survey probably is unnecessary in most cases because of the relatively low level of seismic risk in the fairways of the Marcellus and Utica shales. Additional evaluation or monitoring may be necessary if hydrofracturing fluids might reach a known, significant, mapped fault, such as the Clarendon-Linden fault system.

Recent research has been performed to investigate induced seismicity in an area of active hydrofracturing for natural gas development near Fort Worth, Texas. Studies also were performed to evaluate the cause of the earthquakes associated with the solution mining activity near the Clarendon-Linden fault system near Dale, N.Y. in 1971. The studies indicated that the likely cause of the earthquakes was the injection of fluid for brine disposal for the incidents in Texas, and the injection of fluid for solution mining for the incidents in Dale, N.Y. The studies in Texas also indicate that hydrofracturing is not likely the source of the earthquakes.

The hydrofracturing methods used for enhanced geothermal energy projects are appreciably different than those used for natural gas hydrofracturing. Induced seismicity associated with geothermal energy projects occurs because the hydraulic fracturing is performed at greater depths, within different geologic conditions, at higher pressures, and for substantially longer durations compared with the methods used for natural gas hydrofracturing.

There is a reasonable base of knowledge and experience related to seismicity induced by hydraulic fracturing. Information reviewed in preparing this report indicates that there is essentially no increased risk to the public, infrastructure, or natural resources from induced seismicity related to hydrofracturing. The microseisms created by hydraulic fracturing are too small to be felt, or to cause damage at the ground surface or to nearby wells.

Seismic monitoring by the operators is performed to evaluate, adjust, and optimize the hydrofracturing process. Monitoring beyond that which is typical for hydraulic fracturing does not appear to be warranted, based on the negligible risk posed by the process and very low seismic magnitude. The existing and well-established seismic monitoring network in New York is sufficient to document the locations of larger-scale seismic events and will continue to provide additional data to monitor and evaluate the likely sources of seismic events that are felt.

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TABLES

Table 2.1
Arkansas Regulatory Survey

Agencies:

Gas Drilling is regulated by the Arkansas Oil and Gas Commission

Arkansas Department of Environmental Quality, Division of Water

- Unconventional Sources are those of the Fayetteville, Moorefield, & Chattanooga Shale Formations and their stratigraphic equivalents
- Conventional Sources include all other sources.
- Section (c) lands include Arkansas, Cleburne, Conway, Cross, Faulkner, Independence, Jackson, Lee, Lonoke, Monroe, Phillips, Prairie, St. Francis, Van Buren, White and Woodruff Counties.
- Section (d) lands include Crawford, Franklin, Johnson and Pope Counties (Arkansas Oil and Gas Commission Rule B-43)

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1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

A. Pits

1. Any operator who will construct a test pit, reserve pit, mud pit, circulation pit, or completion pit during drilling at an oil or gas well shall apply for and obtain coverage under General Permit 00000-WG-P prior to construction of said pit. (Arkansas Division of Water, Permit 00000-WG-P, Part I.A.3)

2. A Notice of Intent Form shall be submitted to ADEQ with the following information: Facility name, address, and telephone number; Operator name, address and telephone number; Location of the well; Name and distance to nearest water body; nearest city, town or community; and Signature requirements. The NOI shall also include: USGS Quad Sheet or other topographic map with the well location and nearby lakes, streams or ponds, wetlands, and floodplains within ½ mile from the well pad; schematic with the proposed pit location including the pit dimensions, with well location identified by longitude and latitude; completed Disclosure Statement; and a fee of $300.00. A copy of the NOI and well location map will be submitted to the Arkansas Dept. of Health and the County Judge of the county in which the pit is to be located. (Arkansas Division of Water, Permit 00000-WG-P, Part I.B.1)

3. Construction of production pits, other than those pits previously authorized by Commission Orders is prohibited. (Arkansas Oil & Gas Commission, Rule B-26 (j.2))

Table 2.1 (continued)

4. Emergency Pits: The Arkansas DEQ must be notified in writing immediately after the construction of and emergency pit. (Arkansas Division of Water, Permit 00000-WG-P, Part I.A.3)

5. No person having possession or control of any oil or gas well in a any existing field or pool shall allow any salt water or other oil field wastes produced by such well to escape or be discharged to the ground, or in any other manner which results in the flow of said wastes into any the waters of the State, whether by natural drainage, seepage, overflow, or otherwise. It shall be the duty of such person to confine all such salt water and other oil field wastes or dispose of same in such manner as will prevent their discharge or flow into any of the waters of the State. (Arkansas Pollution Control and Ecology Commission, Regulation 1.4)

6. No person shall hereafter operate any oil or gas well in a new any existing field or pool which produces any salt water or other oil wastes, unless such person shall have first submitted to the Department plans and specifications for a disposal system adequate to prevent the discharge or flow of said wastes into any of the waters of the State and an application for a permit to install and operate such disposal system. The Department shall grant or deny such permit under such terms and conditions as it may prescribe for the prevention of pollution of the waters of the State. Application for a permit shall be made within thirty (30) days after any such well shall have first produced any such wastes. (Arkansas Pollution Control and Ecology Commission, Regulation 1.5)

7. Surface disposal of salt water and other liquid wastes in earthen pits will not be approved unless such pits are underlaid by tight soil such as heavy clay or hardpan, or are lined with asphalt or other water-tight material and are of sufficient size to assure adequate disposal of the volume of waste to be impounded therein. Where the soil under an underground pit is porous and closely underlaid by gravel or sand stratum, impounding of salt water or other liquid wastes therein will not be allowed. An application for a permit to use disposal pits must show that such pits will adequately dispose of the wastes to be impounded therein. When the use of storage pits has been approved, they shall be so constructed and maintained as to prevent escape of wastes there from, whether by seepage or otherwise. (Arkansas Pollution Control and Ecology Commission, Regulation 1.9)

8. Storage pits shall be protected from surface waters by dikes and drainage ditches and no siphons or openings shall be placed in the walls or dikes that would permit the escape of the wastes. Freeboard shall never be less than twelve (12) inches, measured from the lowest point of the top of the dike. . (Arkansas Pollution Control and Ecology Commission, Regulation 1.9)

B. Requirements for Freshwater Based Drilling Fluid Pits (Arkansas Division of Water Permit 00000-WG-P, Part II.A)

1. Pits should have a minimum of a 2:1 (horizontal to vertical) side slope on both interior and exterior walls. The top must be a minimum of 2 ft wide and the pit should have a 2 foot freeboard space. The liner should cover the bottom and inside walls of the pit.

2. Any pit constructed within a 100 yr floodplain must be constructed in accordance with any county or local ordinances or requirements.

3. Pit location shall be chosen to maximize the distance from surface waters. Pit construction in streams, creeks, ponds, or other water bodies is strictly prohibited. Construction in wetlands must be authorized by the US Army Corps of Engineers. When the water table is 10ft or less below the surface, the pit shall be constructed above ground or the operator shall use a closed loop system. Pits must be maintained in a leak free condition

4. Liner. The Liner will consist of one of the following:
    a. A synthetic liner of at least 20 mils thickness with a four inch overlapping welded seam overlap completely covering the pit bottom and inside walls. Sand or sandy material must be placed below the liner if a rocky or uneven surface is encountered. The synthetic liner must be protected from deterioration, punctures, and/or any activity which may damage the integrity of the synthetic liner.
    b. A compacted clay or bentonite liner may be applied to the bottom and sides of the earthen pits create an impervious/impermeable barrier. Construction of the pit and liner shall be in accordance with sound construction and engineering principles designed and constructed to prevent any leakage or seepage to

Table 2.1 (continued)

waters of the state, with due consideration given to the topography, pit material composition, and availability of liner material(s). In the event a compacted clay liner is used, the clay may be in situ or mixed with additional off-site materials if the on site clay is inadequate.

c. Other materials or methods used for liner construction must be approved by the Department prior to use.

C. Operation of Pits for Freshwater Based Drilling Fluids (Arkansas Division of Water Permit 00000-WG-P, Part II.B)

1. Operators of drilling activities are prohibited from disposing into the pit any waste oil, hydraulic fluids, transmission fluids, frac fluids, trash or any other miscellaneous rig waste. Only water based drilling fluids, spent surfactants, and workover fluids may be stored in the pit. In an emergency the pit may be used for additional storage of water based drilling fluids from the same or an adjacent site, then immediately reported to the ADEQ. Pit fluids may not be hauled to another pit offsite for additional storage, except in an emergency or with prior approval from the Director.

2. Circulation and mud pits are recommend to have a 2 ft freeboard to handle up to a 10 yr, 24-hr storm event during the operation of the pit. Any discharge, overflow or seepage from a pit or well site must be reported to the ADEQ Water Division within 24 hrs.

3. Within 30 days after the completion of a test well, each pit shall be emptied of all fluids, waste oil and any NOW fluids. The pit shall be closed in accordance with Arkansas Division of Water Permit 00000-WG-P, Part II.D. (Arkansas Division of Water Permit 00000-WG-P, Part II.E)

4. Pit levees or walls shall be protected and maintained to prevent deterioration, subsequent overfill or leakage of fluids to the waters of the State. Pit liners shall be maintained and protected from deterioration, puncture or leakage until the pit is emptied and closed.

D. Disposal of Freshwater Based Drilling Fluids (Arkansas Division of Water Permit 00000-WG-P, Part II.C)

1. These fluids shall be disposed of by: Land application in accordance with an active ADEQ land application permit; Injected via Class II wells at facilities permitted by AOGC; Freshwater based drilling fluids with high viscosity to high solids concentration may be disposed in situ by combining with available native soils in a manner that prevents runoff of fluids; or by a method approved by ADEQ.

2. Approval from AOGC must be received to pump drilling fluids back down the well bore of a well.

3. Operator must ensure that drilling fluids are removed and properly disposed of.

E. Pit Closure for Freshwater Based Drilling Fluids (Arkansas Division of Water Permit 00000-WG-P, Part II.D)

1. Fluids will be removed to the maximum extent practical. The synthetic liner shall be removed to the extent that is practical and properly disposed of or recycled.

2. The closed pit shall be filled with native materials and covered with topsoil at depths consistent with adjoining onsite areas, with the contour mounded or sloped to discourage erosion and restored as close to the original contours as is practicable. Topsoil and native materials removed during pit construction may be preserved and used during closure. The oil and grease content of the material to be buried in situ shall be less than 3% by dry weight. If the material in the pit is to be solidified or stabilized with fly ash or kiln dust and buried in situ, the material safety data sheet for fly ash or kiln dust and the estimated amount to be used shall be submitted ten days prior to closure of the pit. The permittee is responsible for ensuring the materials are properly mixed to prevent migration of pollutants.

3. The area shall be returned to grade, reclaimed and seeded within a reasonable amount of time not to exceed 180 days after the drilling rig is removed from the site. Vegetative coverage of 75% or equivalent to the surrounding landscape, whichever is less, shall be obtained within 6 months of closure. Until vegetation is established, the operator is responsible for maintaining a stormwater erosion and sediment control plan. The

operator shall submit the Statement of Disposition and NOT form signed by the operator within 90 days after pit closure has been completed.

F. Oil-Based Drilling Mud (OBM) Requirements (Arkansas Division of Water Permit 00000-WG-P, Part II.F)

1. Pit Construction
   a. Pits for OBM systems shall be constructed with a synthetic liner. When the well site is within 100 ft of a pond, lake, stream, ERW, ESW, or NSW, or when the depth to groundwater is less than 10 ft., a closed loop system shall be used.
   b. OBM shall be segregated from water-based muds and other drilling fluids.

2. Pit Closure
   a. OBM shall be removed from the pit and hauled to a permitted Class 1 (as defined by APCEC Regulation No. 22) landfill for disposal or transferred to above ground tanks for re-use at another well location (the muds may or may not be stabilized prior to transport depending on the requirements of the landfill), or other disposal methods or uses of OBM as approved by the Director. The operator shall inform the Department of the location of the disposal of OBM on the NOT.
   b. The liner shall be removed and the site reclaimed to obtain closure as described in Part II of this permit.
   c. If fluid other than diesel is used as the base, additional analytical or disposal requirements may be required, which shall require prior notification and approval by the ADEQ.

3. Other Drilling Muds (Arkansas Division of Water Permit 00000-WG-P, Part II.G)
   a. Other drilling mud systems not specifically authorized by this Permit shall require prior notification and approval by the Department.
   b. These systems may include, but are not limited to: calcium treated, polymer, saltwater, or salt-laden and synthetic muds.

G. Tank Closure

1. All other production pits in existence as of the effective date of this rule shall cease to be used on the effective date of this rule and closed within 90 days after the effective date of this rule in a manner prescribed by the Commission and in accordance with all applicable state laws an regulations, unless exempted in accordance with subsection (4) below. (Arkansas Oil & Gas Commission, Rule B-26 (j.3))

2. Any production pit in existence as of the effective date of this rule, may not be subject to closure in accordance with subsection (j) (3) if:
   a. A) the pit is no longer used for temporary storage of produced fluids; and
   b. B) the water quality in the pit is less than 1500 TDS with no visible sheen of oil; and
   c. C) a written, notarized authorization from the current surface owner has been received by the Director requesting the pit not be closed and demonstrating an acceptable alternative use for the pit; and
   d. D) in determining not to require the pit be closed, the Director shall:
      i. i) review the current location of the pit relative to any ongoing production operations in the area; and
      ii. ii) review the proposed alternative use relative to public health and safety considerations and potential use for agricultural, recreational or wildlife habitat purposes.
   e. E) If the Director determines, based on a review of the information submitted by the operator and surface owner, the pit is not exempted, the pit shall be closed, within six (6) months, by the operator, in accordance with subsection (3) above.

   (Arkansas Oil & Gas Commission, Rule B-26 (j.4))

H. Storage Tanks (Arkansas Oil & Gas Commission, Rule B-26 (d))

1. Tanks or any part of such tanks shall not be buried below the ground surface.

2. All tanks shall be maintained in a leak-free condition.

Table 2.1 (continued)

3. All open top tanks shall be covered with bird netting, or other system designed to keep birds and flying mammals from landing in the tank.

4. 5) All tanks containing produced fluids or equipped to receive produced fluids shall be surrounded by containment dikes or other containment structures as may be appropriate under the circumstances, as approved by the Director.

5. Storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure, and where the vapor accumulation has a Hydrogen Sulfide (H_2S) concentration in excess of 100 ppm, shall be subject to the following:
    a. A. No determination of a radius of exposure shall be made for storage tanks as herein described.
    b. B. A warning sign shall be posted on or within fifty (50) feet of the facility to alert the general public of the potential danger.
    c. C. All tank hatches shall be kept closed at all times except for when it is necessary to inspect or gauge such tanks. All storage tanks that are not fenced as required in (D.) below are required to be kept secured by lock the hatches on all such tanks when not being inspected or gauged.
    d. D. Entry should be restricted to essential personnel only. As a security measure, fencing is required when storage tanks are inside the limits of a city, town site or are reasonably exposed to the public. All means of entry shall be locked when the facility is unattended.
    e. E. All H_2S fumes and vapors shall be either recovered by a vapor recovery unit, flared through a flare stack with a permanent pilot attached thereon or on a case by case basis vented by permit only. Permits to vent will be reviewed with respect to the distance to the nearest public receptor, the concentration of H_2S gas and the volume to be released. (Arkansas Oil & Gas Commission, Rule B-41 (II))

I. Tank Containment (Arkansas Oil & Gas Commission, Rule B-26 (e.1-5, 7))

1. All Crude Oil Tank Batteries and Gas Well Produced Fluids Storage Tanks shall be surrounded by containment dikes or such other structure as may be appropriate under the circumstances, as approved by the Director to prevent waste, protect life, health or property, unless an exception is granted by the Commission following notice and hearing.

2. Required containment dikes or other approved structures shall be designed to have a capacity of at least 1½ times the largest tank the containment dike or approved structure surrounds.

3. Liner Requirements: The natural or man-made material utilized for the construction of the required containment dikes or other approved structures and the natural or man-made material used to line the bottom of the containment area shall be sufficiently impervious so as to contain fluids and resist erosion.

4. Vegetation on the top and outside surface of containment structures shall be properly maintained so as to not pose a fire hazard.

5. The area within the containment dike or other approved containment structure shall be kept free of excessive vegetation, stormwater, produced fluids, other oil and gas field related debris, general trash, or any flammable material. Drain lines installed through the firewall, for the purpose of draining stormwater, shall have a valve installed which shall remain closed and capped when not in use. Any fluids collected, spilled or discharged within such containment structures shall be removed as soon as practical, using the following proper disposal methods:
    a. Produced fluids which have not been mixed with non-exempt RCRA waste as defined by the USEPA, may be recycled through the production equipment or removed from the containment structure and disposed in a properly permitted Class II UIC Well.
    b. Crude oil bottom sediments (BS&W) may be:
        i. applied on oil field lease roads under the following conditions:
            (i) a) application shall be in such a manner as to avoid runoff onto immediately adjacent lands or into waters of the State; and
            (ii) b) immediately following completion of the application, all liquid fractions shall be immediately incorporated into the road bed with no visible free-standing oil; and

(iii) c) no lease road shall be oiled more than twice a year; and
(iv) d) no lease road shall be oiled during precipitation events; and e) the applied BS&W shall not have a produced water content greater than ten percent (10%) free water by volume; or

ii. injected into an inactive oil and gas production well:
(i) a) which has been equipped with tubing and packer, for the purpose of said injection, the packer to be set within the production casing, at least fifty (50) feet below the top of the production casing cement, but no less than five hundred (500) feet below the base of the deepest USDW, and
(ii) b) injection of the BS&W shall not exceed 45 days, after which time the well shall be immediately plugged in accordance with General Rule B-8, and
(iii) c) if the Director determines through field observations that the injection activities are endangering the USDW, the injection activities shall cease until the condition is corrected.

6. Any spill, leak or discharge of produced fluids escaping from a containment dike shall be reported and remediated in accordance with General Rule B-34.

J. Containment Area Disposal

1. When a Crude Oil Tank Battery, Gas Well Produced Fluids Storage Tank or a gas well separator is removed, the Permit Holder shall remove all above ground piping and flowlines coming into said tanks or separator and cap all below ground piping and flowlines, level and grade soil portion of the containment dikes, remove from site all nonsoil containment structure construction material, and remediate all hydrocarbon contaminated soil at tank or separator site in accordance with General Rule B-34. (Arkansas Oil & Gas Commission, Rule B-26 (e.8))

2. Any residual produced fluids remaining within the containment dike, after removal, as required in subsection (e) (5) above, shall be remediated in place in accordance with General Rule B-34. (Arkansas Oil & Gas Commission, Rule B-26 (e.6))

2. Water Well Testing Requirements-None found, yet.

3. Fracturing Fluid Requirements and Fluid Use and Recycling

A. Salt Water Disposal (Arkansas Oil & Gas Commission, Rule C-7 (A))

1. Salt water or other water containing minerals in such amount as to be unfit for domestic, stock, irrigation, or other general uses, upon application to, and approval by the Commission may be disposed of by injection into the following formations:
   a. 1. Non-producing zones of oil or gas-bearing formations that contain water mineralized by processes of nature to such a degree that the water is unfit for domestic, stock, irrigation, or other general use.
   b. 2. All non-producing formations, containing water mineralized by processes of nature to such a degree that water is unfit for domestic, stock, irrigation or other general uses; provided, that before such formations are approved for disposal use, it shall be ascertained that they are separated from fresh water formations by impervious beds which will give adequate protection to such fresh water formations, and that fresh water supplies contained by the proposed disposal formation near its outcrop shall be at a remote distance as not to be endangered by addition of mineralized water in the proposed disposal wells. The Commission, in passing upon applications for the use of non-producing formations for disposal formations, will be advised by the technical recommendations of the State Geological Survey and the State Board of Health in determining whether such formations may be safely and legally used.
   c. 3. Each application shall be accompanied by evidence satisfactory to the Commission of the financial responsibility of the applicant to plug and abandon the disposal well or wells by the method and procedure required by the Commission or the applicant shall be required to furnish a good and sufficient bond therefore in an amount to be determined by the Commission but not to exceed the principal sum of One Hundred Thousand and No/100 Dollars ($100,000.00) conditioned upon the performance of such duty to plug each well to be abandoned.

Table 2.1 (continued)

4. Hydraulic Fracturing Operation Requirements - None

5. Noise and Light Impact Minimization and Mitigation-None found, yet.

6. Setbacks

A. For the purpose of well setback provisions, except in uncontrolled areas, well location is defined as the actual physical location of the completed interval in the well, projected to the surface, as follows:

1. A. In a vertically drilled well without a directional survey, the well location is the surface location. In a vertically drilled well, the well location is the location of the perforated interval of the well bore, projected vertically to the surface;

2. B. In a directionally drilled well, the well location is the location of the midpoint of the perforated interval of the producing formation, as calculated from the directional survey, projected vertically to the surface;

3. C. In a horizontally drilled well, the well location is the entire perforated length of the lateral section of the well bore, as shown on a directional survey, projected vertically to the surface.

(Arkansas Oil & Gas Commission, Rule B-3 (a.2))

B. The spacing of wells in oil and gas fields established by Commission Order, shall be governed by field rules for that particular field, adopted after notice and hearing. The spacing of wells in other areas designated as prospective of oil and gas production shall be governed by General Rule adopted after notice and hearing. (Arkansas Oil & Gas Commission, Rule B-3 (b-c))

C. The well spacing for wells drilled in drilling units for unconventional sources of supply within section c and d lands are as follows:

1. Each well location (as defined in Section (a)(2) of General Rule B-3) shall be at least 560 feet from any drilling unit boundary line;

2. Each well location (as defined in Section (a) (2) of General Rule B-3) shall be at least 560 feet from any other well in the same common source of supply that extends across drilling unit boundaries unless all owners, as defined in Ark. Code Ann. (1987) § 15-72- 102(9), in all units consent in writing to the drilling of a well closer than 560 feet.

3. Each well location (as defined in Section (a) (2) of General Rule B-3) shall be at least 448 feet, an allowed 20% variance, from all other well locations in the same common source of supply within an established drilling unit, unless all owners, as defined in Ark. Code Ann. (1987) § 15-72-102(9), in the unit consent in writing to the drilling of a well closer than 448 feet.

4. No more than 16 wells may be drilled per 640 acres for each separate unconventional source of supply within an established drilling unit; and

5. Applications for exceptions to these well location provisions, relative to a drilling unit boundary or other location in a common source of supply, may be brought before the Commission.

(Arkansas Oil & Gas Commission, Rule B-43 (i))

D. The well spacing for wells drilled in exploratory and established drilling units for all unconventional sources of supply within the covered lands are as follows:

1. Each well location, as defined in General Rule B-3 (a)(2), shall be at least 560 feet from any drilling unit boundary line, unless an exception is approved in accordance with subparagraph (p) below or in accordance with General Rule B- 40;

Table 2.1 (continued)

2. Each well location, as defined in General Rule B-3 (a) (2), shall be at least 560 feet from other well locations within an established drilling unit, within common sources of supply, unless an exception to this rule is approved by the Commission, following notice and hearing.

(Arkansas Oil & Gas Commission, Rule B-44 (h))

E. Storage Tanks

1. Tanks constructed after the effective date of this rule, shall not be located:
    a. A) within 200 feet of an existing occupied habitable dwelling, unless the current owner of the structure has provided a written waiver consenting to the construction closer than 200 feet, in which case the tank battery shall be completely fenced to prevent unauthorized access; however, in no event may a tank battery may be constructed closer that 100 feet to an existing habitable dwelling; or
    b. B) within 300 feet of a school, hospital or other type of public use building as defined in Arkansas Fire Prevention Code Section 3406.3.1.3.1; or
    c. C) within 300 feet of a stream or river designated as an Extraordinary Resource Water (ERW), Natural and Scenic Waterways or Ecological Sensitive Water bodies as defined by APC&E Regulation 2, or within 200 feet of other streams, waterways, rivers, ponds, lakes, wetlands (unless approved by other appropriate governmental agencies), or other bodies of water (as indicated by a blueline designation on a 7.5 minute USGS Topographic Map), unless the Permit Holder utilizes additional containment measures other than the required containment specified in sub-paragraph (e) below, as approved by the Director.

    (Arkansas Oil & Gas Commission, Rule B-26 (d))

7. Multiple Well Pad Reclamation Practices-None Found, yet.

8. NORM

9. Storm Water Runoff

A. Storm Water Erosion and Sediment Controls (Arkansas Division of Water Permit 00000-WG-P)

1. The operator shall prepare a stormwater erosion and sediment control plan (SWESCP) for the well site. The plan shall ensure the implementation of erosion and sediment control practices to reduce pollutants in stormwater discharge from the well pad and access roads. The operator may instead use a guidance document that provides appropriate erosion and sediment controls based on region, terrain, and distance from water bodies approved by the ADEQ.

2. Any facility that potentially discharges stormwater runoff to a water body listed for siltation pursuant to Section 303(d) of the Clean Water Act, or an ERW, ESW or a NSW shall have a specific SWESCP prepared, incorporating BMPs to reasonably reduce listed pollutants.

3. The Operator shall complete and return the Statement of Disposition and Notice of Termination within 90 days after fluid disposal activities have ceased and proper closure of the pit has occurred.

B. Stormwater, which has not been mixed with non-exempt RCRA waste as defined by the EPA, may be drained from the containment structure provided the following conditions are met:

1. the chloride content shall not exceed applicable state water quality standards.
2. there must be no visible evidence of hydrocarbons or hydrocarbon sheen present;
3. the discharge shall only take place during daylight hours;
4. a representative of the Permit Holder must be present during discharge; and the Permit Holder shall maintain a record of each stormwater discharge, occurring in the previous 6 month period, and which shall be available for review upon request by Commission staff. The record shall indicate the location, quantity, chloride content, presence of any hydrocarbons (sheen), and date of discharge

(Arkansas Oil & Gas Commission, Rule B-26 (e.5.A))

Table 2.1 (continued)

C. All stormwater and produced fluids which have been mixed with non-exempt RCRA waste as defined by the USEPA shall be removed and disposed in accordance with applicable Pollution Control and Ecology Commission regulations, as administered by ADEQ. (Arkansas Oil & Gas Commission, Rule B-26 (e.5.C))

D. All Construction Sites must submit Form ARR150000 for the allowance of Storm Water Discharge

1. Sites with a disturbed area of 5 acres or more must also supply:
   a. A Notice of Intent (NOI) in accordance with the requirements of Part I.B.7 of Form ARR150000.
   b. A complete Stormwater Pollution Prevention Plan (SWPPP) in accordance with the requirements of Part II.A of this permit.
   c. An initial permit fee must accompany the NOI under the provisions of APCEC Regulation No. 9. Subsequent annual fees will be billed by the Department until the operator has requested a termination of coverage by submitting a Notice of Termination (NOT). Failure to remit the required permit fee may be grounds for the Director to deny coverage under this general permit.
   d. Per Part I.B.14 of the permit, any single lot thatis less than five (5) acres but part of a larger common plan greater than five (5) acres, is waived from the requirements of a large site and may be permitted under automatic coverage.

   (Arkansas Permit ARR150000, Part I.B (6.B))

2. Discharges from a site into receiving waters for which there is an established total maximum daily load (TMDL) allocation (www.adeq.state.ar.us/water/branch_planning/default.htm) for Turbidity, Oil & Grease, and/or other pollutants at the discretion of the Director are not eligible for coverage under this permit unless the permittee develops and certifies a stormwater pollution prevention plan (SWPPP) that is consistent with the assumptions and requirements in the approved TMDL. To be eligible for coverage under this general permit, operators must incorporate into their SWPPP any conditions applicable to their discharges necessary for consistency with the assumptions and requirements of the TMDL within any timeframes established in the TMDL. If a specific numeric waste load allocation has been established that would apply to the project's discharges, the operator must incorporate that allocation into its SWPPP and implement necessary steps to meet that allocation. Please note that the Department will be reviewing this information. If it is determined that the project will discharge to a TMDL, then the Department may require additional BMPs. (Arkansas Permit ARR150000, Part I.B (11.D))

3. Waivers to Discharge Permit
   a. If all of the stormwater from the construction activity is captured on-site under any size storm event and allowed to evaporate, soak into the ground on-site, or is used for irrigation, a permit is not needed. (Arkansas Permit ARR150000, Part I.B (14.B))
   b. This waiver is available for sites with automatic coverage if the ADEQ has established or approved a TMDL that addresses the pollutant(s) of concern and has determined that controls on stormwater discharges from small construction activity are not needed to protect water quality. The pollutant(s) of concern include sediment (such as total suspended solids, turbidity or siltation) and any other pollutant that has been identified as a cause of impairment of any water body that will receive a discharge from the construction activity. Information on TMDLs that have been established or approved by ADEQ is available from ADEQ online at www.adeq.state.ar.us/water/branch_planning/default.htm. (Arkansas Permit ARR150000, Part I.B (14.C))
   c. This waiver is available for sites with automatic coverage if the ADEQ has listed the waters in 303(d) list that addresses the pollutant(s) of concern and has determined that controls on stormwater discharges from small construction activity are not needed to protect water quality. The pollutant(s) of concern include sediment (such as total suspended solids, turbidity or siltation) and any other pollutant that has been identified as a cause of impairment of any water body that will receive a discharge from the construction activity. Information on 303(d) that have been established by ADEQ is available from ADEQ online at www.adeq.state.ar.us/water/branch_planning/default.htm (Arkansas Permit ARR150000, Part I.B (14.D))
   d. Any single lot, less than 5 acres, that is part of larger common plan may be considered as a small construction site. As long as the operator has complied with all conditions of this permit without submitting an NOI in accordance with 40 CFR 122.28(b) (2) (v). This waiver is applicable if the operator has only one lot in the larger common plan or multiple lots in which construction will not begin within 24 months of the prior construction. (Arkansas Permit ARR150000, Part I.B (14.E))

Table 2.1 (continued)

4. There shall be no turbid discharges to surface waters of the state resulting from dewatering activities. If trench or ground waters contain sediment, it must pass through a sediment settling pond or other equally effective sediment control device, prior to being discharged from the construction site. Alternatively, sediment may be removed by settling in place or by dewatering into a sump pit, filter bag, or comparable practice. Ground water dewatering which does not contain sediment or other pollutants is not required to be treated prior to discharge. However, care must be taken when discharging ground water to ensure that it does not become pollutant-laden by traversing over disturbed soils or other pollutant sources. (Arkansas Permit ARR150000, Part I.B (12))

5. This waiver is available for sites with automatic coverage if the ADEQ has established or approved a TMDL that addresses the pollutant(s) of concern and has determined that controls on stormwater discharges from small construction activity are not needed to protect water quality. The pollutant(s) of concern include sediment (such as total suspended solids, turbidity or siltation) and any other pollutant that has been identified as a cause of impairment of any water body that will receive a discharge from the construction activity. Information on TMDLs that have been established or approved by ADEQ is available from ADEQ online at www.adeq.state.ar.us/water/branch_planning/default.htm. (Arkansas Permit ARR150000, Part I.B (14.C))

6. Excessive Discharges (Arkansas Permit ARR150000, Part I.B (22))
   a. The discharge of hazardous substances or oil in the stormwater discharge(s) from a facility shall be prevented or minimized in accordance with the applicable stormwater pollution prevention plan for the facility. This permit does not relieve the operator of the reporting requirements of 40 CFR Parts 110, 117 and 302. Where a release containing a hazardous substance or oil in an amount equal to or in excess of a reporting quantity established under either 40 CFR 110, 40 CFR 117, or 40 CFR 302, occurs during a 24-hour period, the following action shall be taken:
      i. 1) Any person in charge of the facility is required to notify the National Response Center (NRC) (800-424-8802) in accordance with the requirements of 40 CFR 110, 40 CFR 117, or 40 CFR 302 as soon as he/she has knowledge of the discharge;
      ii. 2) The operator shall submit within five (5) calendar days of knowledge of the release a written description of the release (including the type and estimate of the amount of material released), the date that such release occurred, and the circumstances leading to the release, and steps to be taken in accordance with Part II.B.13 of this permit to the ADEQ.
      iii. 3) The stormwater pollution prevention plan described in Part II.A of this permit must be modified within fourteen (14) calendar days of knowledge of the release to:
         (i) a. Provide a description of the release and the circumstances leading to the release; and
         (ii) b. The date of the release;
   b. Additionally, the plan must be reviewed to identify measures to prevent the reoccurrence of such releases and to respond to such releases, and the plan must be modified where appropriate.

7. The operator must select, install, implement and maintain control measures at the construction site that minimize the discharge of turbidity and/or oil and grease and/or other pollutants at the discretion of the Director as necessary to protect water quality. In general, except in situations explained in below, the stormwater controls developed, implemented, and updated to be considered stringent enough to ensure that your discharges do not cause or contribute to an excursion above any applicable water quality standard. (Arkansas Permit ARR150000, Part I.B (23))

8. The operator must prepare a stormwater pollution prevention plan (the plan/SWPPP) before permit coverage. The plan shall be prepared in accordance with good engineering practices, by qualified personnel and must:
   a. • Identify potential sources of pollution which may reasonably be expected to affect the quality of stormwater discharges from the construction;
   b. • Identify, describe and ensure the implementation of Best Management Practices (BMPs), with emphasis on initial site stabilization, which are to be used to reduce pollutants in stormwater discharges from the construction site;
   c. • Be site specific to what is taking place on a particular construction site;
   d. • Ensure compliance with the terms and conditions of this permit; and
   e. • Identify the responsible party for on-site SWPPP implementation.

   (Arkansas Permit ARR150000, Part II.A)

Table 2.1 (continued)

9. Stormwater Controls (Arkansas Permit ARR150000, Part II.H)
   a. The SWPP must address, at a minimum, the following:
      i. a. For larger common plans, only streets, drainage, utility areas, areas needed for initial construction of streets (e.g., borrow pits, parking areas, etc.) and areas needed for stormwater structures may be disturbed initially. Upon stabilization of the initial areas, additional areas may be disturbed.
      ii. b. The construction-phase erosion (such as site stabilization) and sediment controls (such as check dams) should be designed to retain sediment on-site to the extent practicable.
      iii. c. All control measures must be properly selected, installed, and maintained in accordance with the manufacturer's specifications, good engineering, and construction practices. If periodic inspections or other information indicates a control has been used inappropriately or incorrectly, the permittee must replace or modify the control for site situations.
      iv. d. If sediment escapes the construction site, off-site accumulations of sediment must be removed at a frequency sufficient to minimize off-site impacts (e.g., fugitive sediment in street could be washed into storm sewers by the next rain and/or pose a safety hazard to users of public streets). This permit does not give the authority to trespass onto other property; therefore this condition should be carried out along with the permission of neighboring land owners to remove sediment.
      v. e. Sediment must be removed from sediment traps (if used please specify what type) or sedimentation ponds when design capacity has been reduced by 50%.
      vi. f. Litter, construction debris, and construction chemicals exposed to stormwater shall be prevented from becoming a pollutant source for stormwater discharges (e.g., screening outfalls picked up daily).
      vii. g. Off-site material storage areas (also including overburden and stockpiles of dirt, borrow areas, etc.) used solely by the permitted project are considered a part of the project and shall be addressed in the SWPPP.
   b. The SWPPP must include, at a minimum, the following information:
      i. a. Description and Schedule: A description of initial, interim, and permanent stabilization practices, including site-specific scheduling of the implementation of the practices. Site plans should ensure that existing vegetation is preserved where attainable and that disturbed areas are stabilized. Stabilization practices may include: mulching, temporary seeding, permanent seeding, geotextiles, sod stabilization, vegetative buffer strips, protection of trees, and preservation of mature vegetation and other appropriate measures.
      ii. b. Description of buffer areas: The Department requires that a buffer zone be established between the top of stream bank and the disturbed area. The SWPPP must contain a description of how the site will maintain buffer zones. For construction projects where clearing and grading activities will occur, SWPPP must provide at least twenty-five (25) feet of buffer zone from any named or unnamed streams, creeks, rivers, lakes or other water bodies. The plan must also provide at least fifty (50) feet of buffer zone from established TMDL water bodies, streams listed on the 303 (d)-list, an Extraordinary Resource Water (ERW), Ecologically Sensitive Water body (ESW), Natural and Scenic Waterway (NSW), and/or other uses at the discretion of the Director. If the site will be disturbed within the recommended buffer zone, then the buffer zone area must be stabilized as soon as possible. Exceptions from this requirement for areas, such as water crossings, limited water access, and restoration of the buffer are allowed if the permittee fully documents in the SWPPP the circumstances and reasons for the buffer zone encroachment. Additionally, this requirement is not intended to interfere with any other ordinance, rule or regulation, statute or other provision of law. Please note that above-grade clearing that does not disturb the soil in the buffer zone area does not have to comply with buffer zone requirements.
      iii. c. Records of Stabilization: A record of the dates when major grading activities occur, when construction activities temporarily or permanently cease on a portion of the site, and when stabilization measures are initiated shall be included in the plan.
      iv. d. Deadlines for Stabilization: Stabilization measures shall be initiated as soon as practicable in portions of the site where construction activities have temporarily or permanently ceased, but in no case more than fourteen (14) days after the construction activity in that portion of the site has temporarily or permanently ceased, except:
         (i) (1) Where the initiation of stabilization measures by the fourteenth (14th) day after construction activity temporarily or permanently ceases is precluded by snow cover, stabilization measures shall be initiated as soon as practicable.

Table 2.1 (continued)

(ii) (2) Where construction activity will resume on a portion of the site within twenty-one (21) days from when activities ceased (e.g. the total time period that construction activity is temporarily ceased is less than twenty-one (21) days), then stabilization measures do not have to be initiated on that portion of the site by the fourteenth (14th) day after construction activity temporarily ceased.

c. 3) Structural Practices. A description of structural practices to divert flows from exposed soils, store flows, or otherwise limit runoff and the discharge of pollutants from exposed areas of the site to the degree attainable. Structural practices should be placed on upland soils to the degree attainable. The installation of these devices may be subject to Section 404 of the Clean Water Act. Such practices may include but are not limited to: silt fences (installed and maintained), earthen dikes to prevent run-on, drainage swales to prevent run-on, check dams, subsurface drains, pipe slope drains, storm drain inlet protection, rock outlet protection, sediment traps, reinforced soil retaining systems, gabions, temporary or permanent sediment basins. A combination of erosion and sediment control measures is encouraged to achieve maximum pollutant removal. Adequate spillway cross-sectional area and re-enforcement must be provided for check dams, sediment traps, and sediment basins.

i. a. Sediment Basins.

(i) (1) For common drainage locations that serve an area with ten (10) or more acres (including run-on from other areas) draining to a common point, a temporary or permanent sediment basin that provides storage based on either the smaller of 3600 cubic feet per acre, or a size based on the runoff volume of a 10 year, 24 hour storm, shall be provided where attainable (so as not to adversely impact water quality) until final stabilization of the site. In determining whether installing a sediment basin is attainable, the operator may consider factors such as site soils, slope, available area on site, etc. Proper hydraulic design of the outlet is critical to achieving the desired performance of the basin. The outlet should be designed to drain the basin within twenty-four (24) to seventy-two (72) hours. (A rule of thumb is one square foot per acre for a spillway design.) The 24-hour limit is specified to provide adequate settling time; the seventy-two (72) - hour limit is specified to mitigate vector control concerns. If a pipe outlet design is chosen for the outfall, then an emergency spillway is required. If "non-attainability" is claimed, then an explanation of nonattainability shall be included in the SWPPP**.** Where a sediment basin is not attainable, smaller sediment basins and/or sediment traps shall be used. Where a sediment basin is un-attainable, vegetative buffer strips or other suitable controls which are effective are required for all side slopes and down slope boundaries of the construction area. The plans for removal of the sediment basin should also be included with the description of the basin in the SWPPP.

(ii) (2) For drainage locations serving an area less than ten (10) acres, sediment traps, silt fences, or equivalent sediment controls are required for all side slope and down slope boundaries of the construction area unless a sediment basin providing storage based on either the smaller of 3600 cubic feet per acre, or a size based on the run off volume of a 10 year, 24 hour storm is provided. (A rule of thumb is one square foot per acre for a spillway.) However, in order to protect the waters of the state, the Director, at their discretion, may require a sediment basin for any drainage areas draining to a common point.

ii. b. Velocity Dissipation Devices. Velocity dissipation devices must be placed at discharge locations, within concentrated flow areas serving two or more acres, and along the length of any outfall channel to provide a non-erosive flow velocity from the structure to a water course so that the natural physical and biological characteristics and functions are maintained and protected (i.e., no significant changes in the hydrological regime of the receiving water). Please note that the use of hay-bales is not recommended in areas of concentrated flow.

10. Other Controls (Arkansas Permit ARR150000, Part II.I)

a. No solid materials, including building materials, shall be discharged to waters of the State.

b. 2) Off-site vehicle tracking of sediments and the generation of dust shall be minimized through the use of a stabilized construction entrance and exit and/or vehicle tire washing.

c. 3) For lots that are less than one (1) acre in size an alternative method may be used in addition to a stabilized construction entrance. An example of an alternative method could be daily street sweeping. This could allow for the shortening of the construction entrance.

d. 4) The plan shall ensure and demonstrate compliance with applicable State or local waste disposal, temporary and permanent sanitary sewer or septic system regulations.

Table 2.1 (continued)

e. 5) No liquid concrete waste shall be discharged to waters of the State. Appropriate controls to prevent the discharge of concrete washout waters must be implemented if concrete washout will occur on-site.

f. 6) No contaminants from fuel storage areas, hazardous waste storage and truck wash areas shall be discharged to waters of the State. Methods for protecting these areas shall be identified and implemented. These areas should not be located near a water body, if there is a water body on or near the project.

Table 2.2
Colorado Regulatory Survey

Agency: Oil and Gas Conservation Commission, 1120 Lincoln St., Suite 801, Denver, CO 80203

Regulations, Acts, and Laws:

- OGCC Complete Rules and Regulations, April 1, 2009, (100-1200 series); http://cogcc.state.co.us/

1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

- References: Complete Rules and Regulations, April 1, 2009, (§902, §903, §904, §905); http://cogcc.state.co.us/

A. Tank Requirement

1. All tanks with a capacity of ten (10) barrels or greater shall by September 1, 2009 be labeled or posted with the following information:
   a. Name of operator;
   b. Operator's emergency contact telephone number;
   c. Tank capacity;
   d. Tank contents; and
   e. National Fire Protection Association (NFPA) Label. (COGCC §210)
2. Containers that are used to store, treat, or otherwise handle a hazardous material and which are required to be marked, placarded, or labeled in accordance with the U.S. Department of Transportation's Hazardous Materials Regulations, shall retain the markings, placards, and labels on the container. Such markings, placards, and labels must be retained on the container until it is sufficiently cleaned of residue and purged of vapors to remove any potential hazards. (COGCC §210)
3. All newly installed or replaced crude oil and condensate storage tanks in high density areas shall be designed, constructed, and maintained in accordance with National Fire Protection Association (NFPA) Code 30 (2008 version). The operator shall maintain written records verifying proper design, construction, and maintenance, and shall make these records available for inspection by the Director. Only the 2008 version of NFPA Code 30 applies to this rule. This rule does not include later amendments to, or editions of, the NFPA Code 30. NFPA Code 30 may be examined at any state publication depository library. Upon request, the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203, will provide information about the publisher and the citation to the material. (COGCC §603)

B. Pits - General and Special Rules (COGCC §902)

1. Pits used for exploration and production of oil and gas shall be constructed and operated to protect public health, safety, and welfare and the environment, including soil, waters of the state, and wildlife, from significant adverse environmental, public health, or welfare impacts from Exploration and Production (E&P) waste, except as permitted by applicable laws and regulations.

2. Pits shall be constructed, monitored, and operated to provide for a minimum of two (2) feet of freeboard at all times between the top of the pit wall at its point of lowest elevation and the fluid level of the pit. A method of monitoring and maintaining freeboard shall be employed. Any unauthorized release of fluids from a pit shall be subject to the reporting requirements of Rule 906.

3. Any accumulation of oil or condensate in a pit shall be removed within twenty-four (24) hours of discovery. Operators shall use skimming, steam cleaning of exposed liners, or other safe and legal methods as necessary to maintain pits in clean condition and to control hydrocarbon odors. Only de minimis amounts of hydrocarbons may be present unless the pit is specifically permitted for oil or condensate recovery or disposal use. A Form 15 pit permit may be revoked by the Director and the Director may require that the pit be closed if an operator repeatedly allows more than de minimis amounts of oil or condensate to accumulate in a pit. This requirement is not applicable to properly permitted and properly fenced, lined, and netted skim pits that are designed, constructed, and operated to prevent impacts to wildlife, including migratory birds.

4. Where necessary to protect public health, safety and welfare or to prevent significant adverse environmental impacts resulting from access to a pit by wildlife, migratory birds, domestic animals, or members of the general public, operators shall install appropriate netting or fencing.

5. Pits used for a period of no more than three (3) years, or more than three (3) years if the Director has issued a variance, for storage, recycling, reuse, treatment, or disposal of E&P waste or fresh water, as applicable, may be permitted in accordance with Rule 903 to service multiple wells, subject to Director approval.

6. Unlined pits shall not be constructed on fill material.

7. Except as allowed under Rule 904.a, unlined pits shall not be constructed in areas where pathways for communication with ground water or surface water are likely to exist.

8. Produced water shall be treated in accordance with Rule 907 before being placed in a production pit.

9. Operators shall utilize appropriate biocide treatments to control bacterial growth and related odors as needed.

C. Pit Permitting/Reporting Requirements (COGCC §903)

1. An Earthen Pit Report/Permit, Form 15, shall be submitted to the Director for prior approval for the following pits:
    a. All production pits.
    b. Special purpose pits except those reported under Rule 903.b.(1) or Rule 903.b.(2).
    c. Drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 10,000 ppm TPH or chloride concentrations at total well depth exceeding 15,000 ppm.
    d. Multi-well pits containing produced water, drilling fluids, or completion fluids that will be recycled or reused, except where reuse consists only of moving drilling fluids from one (1) oil and gas location to another such location for reuse there.
2. An Earthen Pit Report/Permit, Form 15, shall be submitted within thirty (30) calendar days after construction for the following:
    a. Special purpose pits used in the initial phase of emergency response.
    b. Flare pits where there is no risk of condensate accumulation.

3. An Earthen Pit Report/Permit, Form 15, shall not be required for drilling pits using water-based bentonitic drilling fluids with concentrations of TPH and chloride below those referenced in Rule 903.a.(3).

4. An Earthen Pit Report/Permit, Form 15, shall be completed in accordance with the instructions in Appendix I. Failure to complete the form in full may result in delay of approval or return of form.

5. The Director shall endeavor to review any properly completed Earthen Pit Report/Permit, Form 15, within thirty (30) calendar days after receipt. In order to allow adequate time for pit permit review and approval, operators shall submit an Earthen Pit Report/Permit, Form 15, at the same time as the Application for Permit to Drill,

Table 2.2 (continued)

Form 2, is submitted. The Director may condition permit approval upon compliance with additional terms, provisions, or requirements necessary to protect the waters of the state, public health, or the environment.

D. Pit Lining Requirements and Specifications (COGCC §904)

1. Pits that were constructed before May 1, 2009 on federal land, or before April 1, 2009 on other land, shall comply with the rules in effect at the time of their construction. The following pits shall be lined if they are constructed on or after May 1, 2009 on federal land, or on or after April 1, 2009 on other land:
   a. Drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 10,000 ppm TPH or chloride concentrations at total well depth exceeding 15,000 ppm.

   b. Production pits , other than skim pits, unless the operator demonstrates to the Director's satisfaction that the quality of the produced water is equivalent to or better than that of the underlying groundwater or the operator can clearly demonstrate by substantial evidence, such as by appropriate percolation tests, that seepage will not reach the underlying aquifer or waters of the state at contamination levels in excess of applicable standards. Subject to Rule 901.c, this requirement shall not apply to such pits in Washington, Yuma, Logan, Morgan, Huerfano, or Las Animas Counties constructed before May 1, 2011.

   c. Special purpose pits, except emergency pits constructed during initial emergency response to spills/releases, or flare pits where there is no risk of condensate accumulation.

   d. Skim pits.

   e. Multi-well pits used to contain produced water, drilling fluids, or completion fluids that will be recycled or reused, except where reuse consists only of moving drilling fluids from one oil and gas location to another such location for reuse there. Subject to Rule 901.c, this requirement shall not apply to multi-well pits used to contain produced water in Washington, Yuma, Logan, Morgan, Huerfano, or Las Animas Counties constructed before May 1, 2011.

   f. Pits at centralized E&P waste management facilities and UIC facilities.

2. The following specifications shall apply to all pits that are required to be lined:

   a. Materials used in lining pits shall be of a synthetic material that is impervious, has high puncture and tear strength, has adequate elongation, and is resistant to deterioration by ultraviolet light, weathering, hydrocarbons, aqueous acids, alkali, fungi or other substances in the produced water.
   b. All pit lining systems shall be designed, constructed, installed, and maintained in accordance with the manufacturers' specifications and good engineering practices.

   c. Field seams must be installed and tested in accordance with manufacturer specifications and good engineering practices. Testing results must be maintained by the operator and provided to the Director upon request.

3. The following specifications shall also apply to pits that are required to be lined, except those at centralized E&P waste management facilities, unless an oil and gas operator demonstrates to the satisfaction of the Director that a liner system offering equivalent protection to public health, safety, and welfare, including the environment and wildlife resources, will be used:

   a. Liners shall have a minimum thickness of twenty-four (24) mils. The synthetic or fabricated liner shall cover the bottom and interior sides of the pit with the edges secured with at least a twelve (12) inch deep anchor trench around the pit perimeter. The anchor trench shall be designed to secure, and prevent slippage or destruction of, the liner materials.

   b. The foundation for the liner shall be constructed with soil having a minimum thickness of twelve (12) inches after compaction covering the entire bottom and interior sides of the pit, and shall be constructed so that the hydraulic conductivity shall not exceed 1.0 x 10-7 cm/sec after testing and compaction. Compaction and permeability test results measured in the laboratory and field must be maintained by the operator and provided to the Director upon request.

c. As an alternative to the soil foundation described in Rule 904.c.(2), the foundation may be constructed with bedding material that exceeds a hydraulic conductivity of 1.0 x 10-7 cm/sec, if a double synthetic liner system is used; however, the bottom and sides of the pit shall be padded with soil or synthetic matting type material and shall be free of sharp rocks or other material that are capable of puncturing the liner. Each synthetic liner shall have a minimum thickness of twenty-four (24) mils.

4. The following specifications shall also apply to pits used at centralized E&P waste management facilities, unless an oil and gas operator demonstrates to the satisfaction of the Director that a liner system offering equivalent protection to public health, safety, and welfare, including the environment and wildlife resources, will be used:

   a. Liners shall have a minimum thickness of sixty (60) mils. The synthetic or fabricated liner shall cover the bottom and interior sides of the pit with the edges secured with at least a twelve (12) inch deep anchor trench around the pit perimeter. The anchor trench shall be designed to secure, and prevent slippage or destruction of, the liner materials.

   b. The foundation for the liner shall be constructed with soil having a minimum thickness of twenty-four (24) inches after compaction covering the entire bottom and interior sides of the pit, and shall be constructed so that the hydraulic conductivity shall not exceed 1.0 x 10-7 cm/sec after testing and compaction. Compaction and permeability test results measured in the laboratory and field must be maintained by the operator and provided to the Director upon request.

   c. As an alternative to the soil foundation described in Rule 904.d.(2), a secondary liner consisting of a geosynthetic clay liner, which is a manufactured hydraulic barrier typically consisting of bentonite clay or other very low permeability material, supported by geotextiles or geomembranes, which are held together by needling, stitching, or chemical adhesives, may be used.

5. In Sensitive Areas, the Director may require a leak detection system for the pit or other equivalent protective measures, including but not limited to, increased record-keeping requirements, monitoring systems, and underlying gravel fill sumps and lateral systems. In making such determination, the Director shall consider the surface and subsurface geology, the use and quality of potentially-affected ground water, the quality of the produced water, the hydraulic conductivity of the surrounding soils, the depth to ground water, the distance to surface water and water wells, and the type of liner.

E. Closure of Pits and Buried or Partially Buried Produced Water Vessels (COGCC §905)

1. Drilling pits shall be closed in accordance with the 1000-Series Rules.

2. Pits not used exclusively for drilling operations, buried or partially buried produced water vessels, and emergency pits shall be closed in accordance with an approved Site Investigation and Remediation Workplan, Form 27. The workplan shall be submitted for prior Director approval and shall include a description of the proposed investigation and remediation activities in accordance with Rule 909. Emergency pits shall be closed and remediated as soon as the initial phase of emergency response operations are complete or process upset conditions are controlled.

   a. Operators shall ensure that soils and ground water meet the concentration levels of Table 910-1.

   b. **Pit evacuation.** Prior to backfilling and site reclamation, E&P waste shall be treated or disposed in accordance with Rule 907.

   c. Liners shall be disposed as follows:

Table 2.2 (continued)

i. **Synthetic liner dispos al.** Liner material shall be removed and disposed in accordance with applicable legal requirements for solid waste disposal.

ii. **Constructed soil liners.** Constructed soil liner material may be removed for treatment or disposal, or, where left in place, the material shall be ripped and mixed with native soils in a manner to alleviate compaction and prevent an impermeable barrier to infiltration and ground water flow and shall meet soil standards listed in Table 910-1.

d. Soil beneath the low point of the pit must be sampled to verify no leakage of the managed fluids. Soil left in place shall meet the standards listed in Table 910-1.

3. **Discovery of a spill/release during closure.** When a spill/release is discovered during closure operations, operators shall report the spill/release on the Spill/Release Report, Form 19, in accordance with Rule 906. Leaking pits and buried or partially buried produced water vessels shall be closed and remediated in accordance with Rules 909. and 910.

4. **Unlined drilling pits.** Unlined drilling pits shall be closed and reclaimed in accordance with the 1000 Series rules and operators shall ensure that soils and ground water meet the concentration levels in Table 910-1.

F. Pit Reclamation (COGCC §1003 & §1004)

1. **Drilling pit closure.** As part of interim reclamation, drilling pits shall be closed in the following manner:

a. **Drilling pit closure on crop land and within 100-year floodplain.** On crop land or within the 100-year floodplain, water-based bentonitic drilling fluids, except *de minimis* amounts, shall be removed from the drilling pit and disposed of in accordance with the 900 Series rules. Operators shall ensure that soils meet the concentration levels of Table 910-1, above. Drilling pit reclamation, including the disposal of drilling fluids and cuttings, shall be performed in a manner so as to not result in the formation of an impermeable barrier. Any cuttings removed from the pit for drying shall be returned to the pit prior to backfilling, and no more than *de minimis* amounts may be incorporated into the surface materials. After the drilling pit is sufficiently dry, the pit shall be backfilled. The backfilling of the drilling pit shall be done to return the soils to their original relative positions. Closing and reclamation of drilling pits shall occur no later than three (3) months after drilling and completion activities conclude.

b. **Drilling pit closure on non-crop land.** All drilling fluids shall be disposed of in accordance with the 900 Series rules. Operators shall ensure that soils meet the concentration levels of Table 910-1, above. After the drilling pit is sufficiently dry, the pit shall be backfilled. Materials removed from the pit for drying shall be returned to the pit prior to the backfilling. No more than *de minimis* amounts may be incorporated into the surface materials. The backfilling of the drilling pit will be done to return the soils to their original relative positions so that the muds and associated solids will be confined to the pit and not squeezed out and incorporated in the surface materials. Closure and reclamation of drilling pits shall occur no later than six (6) months after drilling and completion activities conclude, weather permitting.

c. **Minimum cover.** On crop lands, a minimum of three (3) feet of backfill cover shall be applied over any remaining drilling pit contents. As to both crop lands and non-crop lands, during the two (2) year period following drilling pit closure, if subsidence occurs over the closed drilling pit location additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable.

Table 2.2 (continued)

d. **Production and special purpose pit closure.** The operator shall comply with the 900 series rules for the removal or treatment of E&P waste remaining in a production or special purpose pit before the pit may be closed for final reclamation. After any remaining E&P waste is removed or treated, all such pits must be back-filled to return the soils to their original relative positions. As to both crop lands and non-crop lands, if subsidence occurs over closed pit locations, additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable.

G. Land Application Specifications (COGCC §907)

1. Drilling fluids may be treated or disposed by land treatment or land application at a centralized E&P waste management facility permitted in accordance with Rule 908.

2. **Additional authorized disposal of water-based bentonitic drilling fluids.** Water-based bentonitic drilling fluids may be disposed as follows:

    a. Drying and burial in pits on non-crop land. The resulting concentrations shall not exceed the concentration levels in Table 910-1, below; or

    b. Land application as follows:

        i. **Applicability.** Acceptable methods of land application include, but are not limited to, production facility construction and maintenance, and lease road maintenance.

        ii. **Land applic ation requirements.** The average thickness of water-based bentonitic drilling fluid waste applied shall be no more than three (3) inches prior to incorporation. The waste shall be applied to prevent ponding or erosion and shall be incorporated as a beneficial amendment into the native soils within ten (10) days of application. The resulting concentrations shall not exceed those in Table 910-1.

        iii. **Surface owner approval.** Operators shall obtain written authorization from the surface owner prior to land application of water-based bentonitic drilling fluids.

        iv. **Operator obligations.** Operators shall maintain a record of the source, the volume, and the location where the land application of the water-based bentonitic drilling fluid occurred. Upon the Director's written request, this information shall be provided within five (5) business days, in a format readily reviewable by the Director. Operators with control and authority over the wells from which the water-based bentonitic drilling fluid wastes are obtained retain responsibility for the land application operation, and shall diligently cooperate with the Director in responding to complaints regarding land application of water-based bentonitic drilling fluids.

        v. **Approval.** Prior Director approval is not required for reuse of water-based bentonitic drilling fluids for land application as a soil amendment.

2. Water Well Testing Requirements

References:

- OGCC Complete Rules and Regulations, April 1, 2009, (100-1200 series); http://cogcc.state.co.us/

A. Greater Wattenberg Area Special Regulations (COGCC §318A, e4)

1. The Director shall require initial baseline testing prior to the first interior infill well or boundary well ("proposed GWA infill well") drilled within a governmental section. The following shall be used as guidance for the Director in establishing initial baseline testing:

Table 2.2 (continued)

i. Within the governmental quarter section of the proposed GWA infill well, the closest water well ("water quality testing well") completed in the Laramie/Fox Hills Aquifer shall be sampled.

ii. If no Laramie/Fox Hills water wells are located within the governmental quarter section, then the deepest representative water quality testing well within the governmental quarter section of the proposed GWA infill well shall be sampled.

iii. If no water wells are located within the governmental quarter section, a water quality testing well (preferably completed in the Laramie/Fox Hills Aquifer) within one-half (½) mile of the proposed GWA infill well shall be selected.

iv. If there are no water quality testing wells that meet the foregoing criteria, then initial baseline testing shall not be required.

v. Initial baseline testing shall include laboratory analysis of all major cations and anions, total dissolved solids, iron and manganese, nutrients (nitrates, nitrites, selenium), dissolved methane, pH, and specific conductance.

vi. If free gas or a methane concentration level greater than 2 mg/l is detected in a water quality testing well, compositional analysis shall be performed to determine gas type (thermogenic, biogenic or an intermediate mix of both). If the testing results reveal biogenic gas, no further isotopic testing shall be required. If the testing results reveal thermogenic gas, carbon isotopic analyses of methane carbon shall be conducted. The Director may require further water well sampling at any time as a result of the laboratory results or in response to complaints from water well owners.

vii. Copies of all test results described above shall be provided to the Director and the landowner where the water quality testing well is located within three (3) months of collecting the samples used for the test. Laboratory results shall also be submitted to the Director in an electronic format.

B. Coalbed Methane Wells (COGCC §608)

1. If a conventional gas well or P&A well exists within one-quarter (1/4) mile of a proposed CBM well, then the two (2) closest water wells within a one-half (1/2) mile radius of the conventional gas well or the P&A well shall be sampled ("Water Quality Testing Wells"). If possible, the water wells selected should be on opposite sides of the conventional gas well or the P&A well not exceeding a one-half (1/2) mile radius. If water wells on opposite sides of the conventional gas well or the P&A well cannot be identified, then the two (2) closest wells within a one-half (1/2) mile radius of the conventional gas well or the P&A well shall be sampled. If two (2) or more conventional wells or P&A wells are located within one-quarter (1/4) mile of the proposed CBM well, then the conventional well or the P&A well closest to a proposed CBM well shall be used for selecting water wells for sampling. If there are no conventional gas wells or P&A wells located within a one-quarter (1/4) mile radius of the proposed CBM well, then the selected water wells shall be within one-quarter (1/4) mile of the proposed CBM well. In areas where two (2) or more water wells exist within one-quarter (1/4) mile of the proposed CBM well, then the two (2) closest water wells shall be sampled. If possible, the water wells selected should be on opposite sides of the proposed CBM well. If water wells on opposite sides of the proposed CBM well cannot be identified, then the two (2) closest wells within one-quarter (1/4) mile radius shall be sampled. If two (2) water wells do not exist within a one-quarter (1/4) mile radius, then the closest single water well within either a one-quarter (1/4) mile radius or within a one-half (1/2) mile radius shall be selected. If no water well is located within a one-quarter (1/4) mile radius area as described above or if access is denied, then a water well within one-half (1/2) mile of the proposed CBM well shall be selected. If no water wells meet the foregoing criteria, then sampling shall not be required. If the Commission has already acquired data on a water well within one-quarter (1/4) mile of the conventional well or the P&A well, but it is not the closest water well, then it shall be given preference in selecting a water well to be tested.

2. The "initial baseline testing" described in this section shall include all major cations and anions, total dissolved solids (TDS), iron, manganese, selenium, nitrates and nitrites, dissolved methane, field pH, sodium adsorption ration (SAR), presence of bacteria (iron related, sulfate reducing, slime, and coliform), and specific conductance. Hydrogen sulfide shall also be measured using a field test method. Field

observations such as odor, water color, sediment, bubbles, and effervescence shall also be included. The location of the water well shall be surveyed in accordance with Rule 215.

3. If free gas or a dissolved methane concentration level greater than two (2) milligrams per liter (mg/l) is detected in a water well, gas compositional analysis and stable isotope analysis of the methane (carbon and deuterium) shall be performed to determine gas type. If the test results indicate biogenic gas, no further isotopic testing shall be done. If the test results indicate thermogenic or a mixture of thermogenic and biogenic gas, then the operator shall submit to the Director an action plan to determine the source of the gas. If the methane concentration increases by more than five (5) mg/l between sampling periods, or increases to more than ten (10) mg/l, the operator shall notify the Director and the owner of the water well immediately.
4. Operators shall make a good faith effort to conduct initial baseline testing of the selected water wells prior to the drilling of the proposed CBM well; however, not conducting baseline testing because access to water wells cannot be obtained shall not be grounds for denial of an Application for Permit-to-Drill, Form 2. Within one (1) year after completion of the proposed CBM well, a "post-completion" test shall be performed for the same analytical parameters listed above and repeated three (3) and six (6) years thereafter or in accordance with the requirements of field rules developed pursuant to Rule 608.f. If the methane concentration increases by more than five (5) mg/l between sampling periods or increases to more than ten (10) mg/l, the operator shall prepare an action plan to determine the source of the gas and notify the Director and the water well owner immediately. If no significant changes from the baseline have been identified after the third test (i.e. the six-year test), no further testing shall be required. Additional "post-completion" test(s) may be required if changes in water quality are identified during follow-up testing. The Director may require further water well sampling at any time in response to complaints from water well owners.
5. Copies of all test results described above shall be provided to the Commission and the water well owner within three (3) months of collecting the samples. The analytical data and surveyed well locations shall also be submitted to the Director in an electronic data deliverable format.

3. Fracturing Fluid Requirements and Fluid Use and Recycling – No Information

4. Hydraulic Fracturing Operation Requirements – No Information

5. Noise and Light Impact Minimization and Mitigation

I. Noise (COGCC §802)

A. In the hours between 7:00 a.m. and the next 7:00 p.m. the noise levels permitted below may be increased ten (10) db(A) for a period not to exceed fifteen (15) minutes in any one (1) hour period. The allowable noise level for periodic, impulsive or shrill noises is reduced by five (5) db(A) from the levels shown.

ZONE	**7:00 am to next 7:00 pm**	**7:00 pm to next 7:00 am**
Residential/Agricultural/Rural	55 db(A)	50 db(A)
Commercial	60 db(A)	55 db(A)
Light industrial	70 db(A)	65 db(A)
Industrial	80 db(A)	75 db(A)

Table 2.2 (continued)

In remote locations, where there is no reasonably proximate occupied structure or designated outside activity area, the light industrial standard may be applicable.
Pursuant to Commission inspection or upon receiving a complaint from a nearby property owner or local governmental designee regarding noise related to oil and gas operations, the Commission shall conduct an onsite investigation and take sound measurements as prescribed herein.

The following provide guidance for the measurement of sound levels and assignment of points of compliance for oil and gas operations:

1. Sound levels shall be measured at a distance of three hundred and fifty (350) feet from the noise source. At the request of the complainant, the sound level shall also be measured at a point beyond three hundred fifty (350) feet that the complainant believes is more representative of the noise impact. If an oil and gas well site, production facility, or gas facility is installed closer than three hundred fifty (350) feet from an existing occupied structure, sound levels shall be measured at a point twenty-five (25) feet from the structure towards the noise source. Noise levels from oil and gas facilities located on surface property owned, leased, or otherwise controlled by the operator shall be measured at three hundred and fifty (350) feet or at the property line, whichever is greater. In situations where measurement of noise levels at three hundred and fifty (350) feet is impractical or unrepresentative due to topography, the measurement may be taken at a lesser distance and extrapolated to a 350-foot equivalent using the following formula:

   db(A) DISTANCE 2 = db(A) DISTANCE 1 – 20 x log 10 (distance 2/distance 1)

2. Sound level meters shall be equipped with wind screens, and readings shall be taken when the wind velocity at the time and place of measurement is not more than five (5) miles per hour.

3. Sound level measurements shall be taken four (4) feet above ground level.

4. Sound levels shall be determined by averaging minute-by-minute measurements made over a minimum fifteen (15) minute sample duration if practicable. The sample shall be taken under conditions that are representative of the noise experienced by the complainant (e.g., at night, morning, evening, or during special weather conditions).

5. In all sound level measurements, the existing ambient noise level from all other sources in the encompassing environment at the time and place of such sound level measurement shall be considered to determine the contribution to the sound level by the oil and gas operation(s).

B. In situations where the complaint or Commission onsite inspection indicates that low frequency noise is a component of the problem, the Commission shall obtain a sound level measurement twenty-five (25) feet from the exterior wall of the residence or occupied structure nearest to the noise source, using a noise meter calibrated to the db(C) scale. If this reading exceeds 65 db(C), the Commission shall require the operator to obtain a low frequency noise impact analysis by a qualified sound expert, including identification of any reasonable control measures available to mitigate such low frequency noise impact. Such study shall be provided to the Commission for consideration and possible action.

C. Exhaust from all engines, motors, coolers and other mechanized equipment shall be vented in a direction away from all building units.

D. All facilities within four hundred (400) feet of building units with engines or motors which are not electrically operated shall be equipped with quiet design mufflers or equivalent. All mufflers shall be properly installed and maintained in proper working order.

II. Lighting (COGCC §803)

A. To the extent practicable, site lighting shall be directed downward and internally so as to avoid glare on public roads and building units within seven (700) hundred feet.

6. Setbacks

References:

- Complete Rules and Regulations, April 1, 2009, (100-1200 series); http://cogcc.state.co.us/

  Regulations, Acts, and Laws (COGCC §318)

1. **Wells 2,500 feet or greater in depth.** A well to be drilled two thousand five hundred (2,500) feet or greater shall be located not less than six hundred (600) feet from any lease line, and shall be located not less than one thousand two hundred (1,200) feet from any other producible or drilling oil or gas well when drilling to the same common source of supply, unless authorized by order of the Commission upon hearing.

2. **Wells less than 2,500 feet in depth.** A well to be drilled to less than a depth of two thousand five hundred (2,500) feet below the surface shall be located not less than two hundred (200) feet from any lease line, and not less than three hundred (300) feet from any other producible oil or gas well, or drilling well, in said source of supply, except that only one producible oil or gas well in each such source of supply shall be allowed in each governmental quarter-quarter section unless an exception under Rule 318.c. is obtained.

3. **Exception locations.** The Director may grant an operator's request for a well location exception to the requirements of this rule or any order because of geologic, environmental, topographic or archaeological conditions, irregular sections, a surface owner request, or for other good cause shown provided that a waiver or consent signed by the lease owner toward whom the well location is proposed to be moved, agreeing that said well may be located at the point at which the operator proposes to drill the well and where correlative rights are protected. If the operator of the proposed well is also the operator of the drilling unit or unspaced offset lease toward which the well is proposed to be moved, waivers shall be obtained from the mineral interest owners under such lands. If waivers cannot be obtained from all parties and no party objects to the location, the operator may apply for a variance under Rule 502.b. If a party or parties object to a location and cannot reach an agreement, the operator may apply for a Commission hearing on the exception location.

4. **Wells located near a mine.** No well drilled for oil or gas shall be located within two hundred (200) feet of a shaft or entrance to a coal mine not definitely abandoned or sealed, nor shall such well be located within one hundred (100) feet of any mine shaft house, mine boiler house, mine engine house, or mine fan; and the location of any proposed well shall insure that when drilled it will be at least fifteen (15) feet from any mine haulage or airway.

A. Setback Exemptions

1. This rule shall not apply to authorized secondary recovery projects.

2. This rule shall apply to fracture or crevice production found in shale, except from fields previously exempted from this rule.

3. In a unit operation, approved by federal or state authorities, the rules set forth herein shall not apply except that no well in excess of two thousand five hundred (2,500) feet in depth shall be located less than six hundred

(600) feet from the exterior or interior (if there be one) boundary of the unit area and no well less than two thousand five hundred (2,500) feet in depth below the surface shall be located less than two hundred (200) feet from the exterior or interior (if there be one) boundary of the unit area unless otherwise authorized by the order of the commission after proper notice to owner's outside the unit area.

B. Recent Regulations (COGCC §317B)

1. **Public Water System Protection** - The buffer zones shall apply only to Drilling, Completion, Production, and Storage (DCPS) Operations located on the surface. The buffer zones shall not apply to subsurface boreholes and equipment or materials contained therein. The buffer zones shall not apply to DCPS Operations located in an area that does not drain to a classified water supply segment protected by this Rule 317B.

2. **Buffer zones shall be**: Internal Buffer = 0-300 feet; Intermediate Buffer = 301-500 feet; External Buffer = 501 – 2640 feet.

3. **For Intermediate and External Buffer Zones** - Notification of potentially impacted Public Water Systems within fifteen (15) stream miles downstream of the DCPS Operation prior to commencement of new surface disturbing activities at the site.

7. Multi-Well Reclamation – No Information

8. Storm Water Best Management Practices for Sites with Greater Than 1 Acre of Total Disturbance

- References: Complete Rules and Regulations, April 1, 2009, (100-1200 series); http://cogcc.state.co.us/

III. **Stormwater management.** (COGCC §1002)

1. All oil and gas locations are subject to the Best Management Practices requirements of Rule 1002.f.(2). In addition, upon the termination of a construction stormwater permit issued by the Colorado Department of Public Health and Environment for an oil and gas location, such oil and gas location is subject to the Post-Construction Stormwater Program requirements of Rule 1002.f.(3), except that such requirements are not applicable to Tier 1 Oil and Gas Locations.

2. Oil and gas operators shall implement and maintain Best Management Practices (BMPs) at all oil and gas locations to control stormwater runoff in a manner that minimizes erosion, transport of sediment offsite, and site degradation. BMPs shall be maintained until the facility is abandoned and final reclamation is achieved pursuant to Rule 1004. Operators shall employ BMPs, as necessary to comply with this rule, at all oil and gas locations, including, but not limited to, well pads, soil stock piles, access roads, tank batteries, compressor stations, and pipeline rights of way. BMPs shall be selected based on site-specific conditions, such as slope, vegetation cover, and proximity to water bodies, and may include maintaining in-place some or all of the BMPs installed during the construction phase of the facility. Where applicable based on site-specific conditions, operators shall implement BMPs in accordance with good engineering practices, including measures such as:

   a. **Covering materials and activities and stormwater diversion** to minimize contact of precipitation and stormwater runoff with materials, wastes, equipment, and activities with potential to result in discharges causing pollution of surface waters.

   b. **Materials handling and spill prevention procedures and practices** implemented for material handling and spill prevention of materials used, stored, or disposed of that could result in discharges causing pollution of surface waters.

   c. **Erosion controls** designed to minimize erosion from unpaved areas, including operational well pads, road surfaces and associated culverts, stream crossings, and cut/fill slopes.

Table 2.2 (continued)

d. **Self-inspection, maintenance, and good housekeeping procedures and schedules** to facilitate identification of conditions that could cause breakdowns or failures of BMPs. These procedures shall include measures for maintaining clean, orderly operations and facilities and shall address cleaning and maintenance schedules and waste disposal practices. In conducting inspections and maintenance relative to stormwater runoff, operators shall consider seasonal factors, such as winter snow cover and spring runoff from snowmelt, to ensure site conditions and controls are adequate and in place to effectively manage stormwater.

e. **Spill response procedures** for responding to and cleaning up spills. The necessary equipment for spill cleanup shall be readily available to personnel. Spill Prevention, Control, and Countermeasure plans incorporated by reference must be identified in the Post-Construction Stormwater Management Program specified in Rule 1002.f.(3).

f. **Vehicle tracking control practices** to control potential sediment discharges from operational roads, well pads, and other unpaved surfaces. Practices could include road and pad design and maintenance to minimize rutting and tracking, controlling site access, street sweeping or scraping, tracking pads, wash racks, education, or other sediment controls.

3. Operators of oil and gas facilities shall develop a Post-Construction Stormwater Program in compliance with this section no later than the time of termination of stormwater permits issued by the Colorado Department of Public Health and Environment for construction of oil and gas facilities.

   a. The Post-Construction Stormwater Program shall reflect good faith efforts by operators to select and implement BMPs intended to serve the purposes of this rule. BMPs shall be selected to address potential sources of pollution which may reasonably be expected to affect the quality of discharges associated with the ongoing operation of production facilities during the post-construction and reclamation operation of the facilities. Pollutant sources that must be addressed by BMPs, if present, include:

      i. Transport of chemicals and materials, including loading and unloading operations;

      ii. Vehicle/equipment fueling;

      iii. Outdoor storage activities, including those for chemicals and additives;

      iv. Produced water and drilling fluids storage;

      v. Outdoor processing activities and machinery;

      vi. Significant dust or particulate generating processes;

      vii. Erosion and vehicle tracking from well pads, road surfaces, and pipelines;

      viii. Waste disposal practices;

      ix. Leaks and spills; and

      x. Ground-disturbing maintenance activities.

4. The Post-Construction Stormwater Program shall be developed, supervised, documented, and maintained by a qualified person(s) with training or prior work experience specific to stormwater management. Employees and subcontractors shall be trained to make them aware of the BMPs implemented and maintained at the site and procedures for reporting needed maintenance or repairs. Documentation shall include a description of the BMPs selected to ensure proper implementation, operation, and maintenance.

5. Facility-specific maps, installation specification, and implementation criteria shall also be included when general operating procedures and descriptions are not adequate to clearly describe the implementation and operation of BMPs.

9. NORMs – No Information

Table 2.3
Louisiana Regulatory Survey

Agency: Gas Drilling is regulated by the Department of Environmental Protection, Office of Conservation

- Louisiana Revised Statutes, Title 30, Minerals, Oil and Gas and Environmental Quality http://www.deq.state.la.us/portal/Portals/0/planning/regs/EQA%202007.pdf
- Louisiana Administrative Code, Title 43, Natural Resources http://doa.louisiana.gov/osr/lac/lac43.htm
- Louisiana Administrative Code, Title 33:IX, Water Quality http://www.deq.louisiana.gov/portal/tabid/1674/Default.aspx#ERC
- Louisiana Administrative Code, Title 33:XV, Chapter 14, Radiation Protection, NORM http://www.deq.louisiana.gov/portal/tabid/1674/Default.aspx#ERC
- Louisiana DEQ Permit No. LAG330000, General Permit for Oil and Gas Exploration, Development, and Production Facilities Located Within Coastal Waters http://www.deq.louisiana.gov/portal/Default.aspx?tabid=245
- Louisiana DEQ Permit No. LAR200000, Storm Water General Permit for Small Construction Activities http://www.deq.louisiana.gov/portal/Default.aspx?tabid=245
- Louisiana State Review of Oil and Natural Gas Environmental Regulations, Inc., 2004 http://www.strongerinc.org/documents/Final%20LA%20Report.pdf
- Order establishing reasonable and uniform practices, safeguards and regulations for present and future operations related to the exploration for and production of gas from the Haynesville Zone in urban areas. (DRAFT)

1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

A. Regulations

1. All wells shall be cleaned into a pit, barge, or tank, located at a distance of at least 100 feet from any fire hazard. (Louisiana Administrative Code, Title 43, Part 19, §115 (A.1))

2. The use of closed Exploration and Production Waste storage systems is encouraged by the Office of Conservation; therefore, the use of new or existing pits to store produced water, drilling fluids, and other E&P Waste generated from the drilling and production of oil and gas wells is prohibited unless:
   a. notification for each pit is submitted to the Office of Conservation as outlined in §305; and
   b. pits are in conformance with standards set forth in §307. (Louisiana Administrative Code, Title 43, Part 19, §303 (F))

3. Operators of existing pits are required to comply with all applicable operational requirements of §307.A.2 and 4, §307.B.1, 2, and 3, §307.C.2, 4, 5, and 6, §307.D.2, 4, and 5, §307.E.1, 3, 4, and 6, and §307.F.1 and 3.

4. A representative of the Office of Conservation must be given an opportunity to inspect prior to and during construction of the pit as provided under §305.B. (Louisiana Administrative Code, Title 43, Part 19, §307 (A.3))

5. As of January 1, 1993 there are to be no production pits within inland tidal waters, lakes bounded by the Gulf of Mexico, and saltwater marshes. (Louisiana Revised Statutes, Title 30, Part 25, (A))

B. Liner Requirements

Table 2.3 (continued)

1. Unless exempted from liner requirements in §303.K.8 or §303.M below, all existing produced water pits, onshore terminal pits, and washout pits which are to be utilized in the operation of oil and gas or other facilities must be shown to comply with the liner requirements of §307.A.1.a or be permanently closed in accordance with the pit closure criteria of §311 and §313 by January 20, 1989. A certification attesting to compliance with these requirements shall be submitted to this office in a timely manner. (Louisiana Administrative Code, Title 43, Part 19, §303 (G))

2. Based upon the best practical technology, production pits located within an 'A' zone (FEMA) which meet the following criteria are not subject to the levee height requirements of §303.J above or the liner requirements of §307.A.1:
   a. pit size is less than or equal to 10' x 10' x 4' deep;
   b. such pit contains only produced brine; and
   c. such pit is utilized for gas wells producing less than 25 mcf per day and less than or equal to one barrel of saltwater per day (bswpd).

   (Louisiana Administrative Code, Title 43, Part 19, §303 (M))

C. Location

1. Pits may not be constructed within coastal areas. (Louisiana Administrative Code, Title 43, Part 19, §303 (K))

2. Production pits, except for those identified in §303.K.1 and §303.M below, may not be constructed in a "V" or A zone as determined by flood hazard boundary or rate maps and other information published by the Federal Emergency Management Agency (FEMA), unless such pits have levees which have been built at least 1 foot above the 100-year flood level and able to withstand the predicted velocity of the 100-year flood. Location, construction and use of such pits is discouraged. (Louisiana Administrative Code, Title 43, Part 19, §303 (J))

3. Pits shall be protected from surface waters by levees or walls and by drainage ditches, where needed, and no siphon or openings will be placed in or over levees or walls that would permit escaping of contents so as to cause pollution or contamination. Authorized surface discharges of pit contents under federal and/or state regulatory programs are not considered to be pollution or contamination as used herein. . (Louisiana Administrative Code, Title 43, Part 19, §307 (A.2))

D. Waste Requirements

1. Within six months of the completion of the drilling or workover of any permitted well, the operator (generator) shall certify to the commissioner by filing Form ENG-16 the types and number of barrels of E&P Waste generated, the disposition of such waste, and further certify that such disposition was conducted in accordance with applicable rules and regulations of the Office of Conservation. Such certification shall become a part of the well's permanent history. (Louisiana Administrative Code, Title 43, Part 19, §303 (L))

2. The commissioner may authorize, without the necessity of a public hearing, the disposal of produced water into a zone producing or productive of hydrocarbons upon application of the operator of an existing or proposed disposal well. Such written request shall include the following:
   a. the appropriate permit application as per the requirements of LAC 43:XIX.Chapter 4;
   b. evidence establishing the production mechanism of the proposed disposal zone is aquifer expansion (water drive);
   c. evidence demonstrating the subject disposal well is not productive in the proposed disposal zone;
   d. a plat showing the subject disposal well is not located within 330' of a property line as it is defined in LAC 43:XIX.1901;
   e. written consent of all operators of record with existing wells within a 1/4 mile radius of the subject well; and
   f. such other information which the commissioner may require.

   (Louisiana Administrative Code, Title 43, Part 19, §303 (O))

3. Within 30 days after completion of a well test, pits shall be emptied of produced fluids and must remain empty of produced fluids during periods of nonuse. (Louisiana Administrative Code, Title 43, Part 19, §307 (D.4))

Table 2.3 (continued)

E. Freeboard Requirement

1. Except where exempted by §303.K.8 and §303.M, groundwater aquifer and USDW protection for above-listed pits shall be provided by one of the following. (Louisiana Administrative Code, Title 43, Part 19, §307 (A))
   a. A liner along the bottom and sides of pits which has the equivalent of 3 continuous feet of recompacted or natural clay having a hydraulic conductivity no greater than 1 x 10^{-7} cm/sec. Such liners include, but are not limited to the following.
      i. *Natural Liner*—natural clay having a hydraulic conductivity meeting the requirements of §307.A.1.a above.
      ii. *Soil Mixture Liner*—soil mixed with cement, clay-type, and/or other additives to produce a barrier which meets the hydraulic conductivity requirements of §307.A.1.a above.
      iii. *Recompacted Clay Liner*—in situ or imported clay soils which are compacted or restructured to meet the hydraulic conductivity requirements of §307.A.1.a above.
      iv. *Manufactured Liner*—synthetic material that meets the definition in §301 and is equivalent or exceeds the hydraulic conductivity requirements of §307.A.1.a above. Pits constructed with a manufactured liner must have side slopes of 3:1 and the liner at the top of the pit must be buried in a 1' wide and 1' deep trench. A sufficient excess of liner material shall be placed in the pit to prevent tearing when filled with E&P Waste.
      v. *Combination Liner*—a combination of two or more types of liners described in this Section which meets the hydraulic conductivity requirements of §307.A.1.a above.
   b. Any other alternate groundwater aquifer and USDW protection system acceptable to the Office of Conservation.
2. Liquid levels in pits shall not be permitted to rise within 2 feet of top of pit levees or walls. Pit levees or walls shall be maintained at all times to prevent deterioration, subsequent overfill, and leakage of Exploration & Protection Waste to the environment. Louisiana Administrative Code, Title 43, Part 19, §307 (A.4))

F. Pit Closure

1. Evidence of contamination of a groundwater aquifer or USDW may require compliance with the monitoring program of §309, compliance with the liner requirements of §307.A.1, or immediate closure of the pit. (Louisiana Administrative Code, Title 43, Part 19, §303 (N))

2. When use of a pit will be permanently discontinued by the operator of record, the Office of Conservation shall be notified in writing. Pits shall be emptied of all fluids in a manner compatible with all applicable regulations and closed in accordance with §303.F and G within six months of abandonment. Louisiana Administrative Code, Title 43, Part 19, §307 (A.5))

3. Mineral exploration and production sites shall be cleared, revegetated, detoxified, and otherwise restored as near as practicable to their original condition upon termination of operations to the maximum extent practicable. (Louisiana Administrative Code, Title 43, Part 1, §719 (M))

G. Emergency Pits

1. Groundwater aquifer and USDW protection for emergency pits shall be evaluated on a case-by-case basis. Operators who intend to utilize existing or new emergency pits without liners must demonstrate by written application to the Office of Conservation that groundwater aquifer and USDW contamination will not occur; otherwise, emergency pits shall be lined. Applications to demonstrate unlined pits will not contaminate groundwater aquifers and USDW's shall at a minimum address the following.
   a. *Emergency Incident Rate*—operator shall estimate the number of times a pit will be utilized each year. A detailed discussion of the facility operation and reasons for the emergency incident rate must be addressed.
   b. *Soil Properties*—operator shall describe and evaluate soil properties onsite. Soil hydraulic conductivity and physical properties must be addressed to assess potential groundwater aquifer and USDW impacts.
   c. *Groundwater Aquifer Evaluation*—water quality, groundwater aquifer, and USDW depth shall be evaluated.

Table 2.3 (continued)

d. *Produced Water Composition* (total dissolved solids and oil and grease)—must be determined to assess potential impacts on the site.

2. All emergency pits required to be lined must conform to hydraulic conductivity requirements in §307.A.1 above.

3. No produced water or any other Exploration & Production Waste shall be intentionally placed in any emergency pit not meeting the hydraulic conductivity requirements (1 x 10^{-7} cm/sec for 3 continuous feet of clay) except in the case of an emergency incident. In emergency situations, notice must be given to the Office of Conservation within 24 hours after discovery of the incident. Produced water and any other Exploration & Production Waste must be removed from the pit within seven days following termination of the emergency situation.

4. Pits shall be protected from surface waters by levees and by drainage ditches, where needed, and no siphons or openings will be placed in or over levees or walls that would permit escaping of contents so as to cause pollution or contamination. Surface discharges of pit contents under federal or state permits are not considered to be pollution or contamination as used herein.

5. A representative of the Office of Conservation must be given an opportunity to inspect prior to and during construction of the pits as provided under §305.B.

6. Liquid level in pits shall not be permitted to rise within 2 feet of top of pit levees. Pit levees or walls shall be maintained at all times to prevent deterioration, subsequent overfill, and leakage of E&P Waste to the environment.

7. When use of pits will be permanently discontinued, the Office of Conservation shall be notified in writing. After notification to the Office of Conservation, pits shall be emptied of all fluids in a manner compatible with all Title 43, Part XIX applicable regulations, and closed in accordance with §311 and §313 within six months of abandonment.

2. Water Well Testing Requirements

A. If the owner or operator of any oilfield site or exploration and production (E&P) site covered by the provisions of R.S. 30:29 performs any environmental testing on land owned by another person, results of such environmental testing shall be provided to the owner or owners of the land within ten days from receipt of such results by the owner or operator, regardless of whether or not suit has been filed by the owner or owners of the land. The operator or owner or owners of land or anyone acting on their behalf who perform any environmental testing on land that is an oilfield or exploration and production (E&P) site shall provide the results of such testing to the department within ten days of receipt. (Louisiana Revised Statutes, Title 30, Part 29.1)

3. Fracturing Fluid Requirements and Fluid Use and Recycling

A. Surface Water Use Restrictions and Regulations

1. The assistant secretary shall make, after notice and public hearing as provided in this Chapter, any reasonable rules, regulations, and orders which are necessary to prohibit the operators of oil and gas wells from performing any acts on lands subject to a drilling permit which may preclude agents of the Department of Wildlife and Fisheries from effectively enforcing any of the provisions of Title 56 of the Louisiana Revised Statutes of 1950. The assistant secretary shall revoke any permit granted to an operator and deny any application for a permit to drill any well by an operator found to be in violation of the rules provided for in this Section. (Louisiana Revised Statutes, Title 30, Part 4, §2)

2. Upland and upstream water management programs which affect coastal waters and wetlands shall be designed and constructed to preserve or enhance existing water quality, volume, and rate of flow to the maximum extent practicable. (Louisiana Administrative Code, Title 43, Part 1, §717 (A))

Table 2.3 (continued)

3. Valid Coastal Use permits are required for surface water control or consumption, including marsh management projects within the coastal zone (Louisiana Administrative Code, Title 43, Part 1, §723 (A.2.h))
   a. In-Lieu Permits. Coastal use permits shall not be required for the location, drilling, exploration and production of oil, gas, sulfur and other minerals subject to regulation by the Office of Conservation of the Department of Natural Resources as of January 1, 1979. The parameters and procedures of the in-lieu permit process are as provided for under existing Memorandum of Understanding between the Coastal Management Section and the Office of Conservation and the rules and procedures of the Office of Conservation. (Louisiana Administrative Code, Title 43, Part 1, §723 (A.3))

4. If ground water must be used for drilling or hydraulic fracture stimulation purposes, it is recommended that the Red River Alluvial aquifer be utilized for these purposes, where feasible, as the source of ground water supply in lieu of the Carrizo - Wilcox aquifer. (Groundwater Use Advisory, 2008)
   a. The Commissioner encourages oil and gas operators to use the available surface water resources or other acceptable alternative water sources in Northwest Louisiana, where practical and feasible.
      i. The Carrizo – Wilcox aquifer system is a low yield aquifer system that generally produces water suitable for drinking water purposes which has been and is currently being used predominately for domestic and public water supply in mostly rural areas of Northwest Louisiana. However, water production from the aquifer system is reported to be physically restricted due to the aquifer's discontinuous nature and typically thin, lenticular and fine textured sand beds.
      ii. The Red River Alluvial aquifer system is a high yield system comprised of coarse gravel and sand formations continuously recharged by the surface waters of the Red River. It is further documented that the Red River Alluvial aquifer system, due to its hardness and high dissolved solids, is seldom used for domestic and public supply purposes, and is predominately used for industrial purposes.

5. Well Water Use
   a. An operator using a water well to supply water to a well covered by this Order, whether for drilling or fracturing operations, shall comply with the provisions of LSA-R.S. 38:3097 et seq., and the rules and regulations of the Office of Conservation promulgated pursuant thereto. (Office of Conservation-Haynesville Drilling Regulations, Draft (3-J))

B. Drilling Mud

1. The inspectors and engineers of the Department of Conservation shall have access to the mud records of any drilling well, except those records which pertain to special muds and special work with respect to patentable rights, and shall be allowed to conduct any essential test or tests on the mud used in the drilling of a well. When the conditions and tests indicate a need for a change in the mud or drilling fluid program in order to insure proper control of the well, the district manager shall require the operator or company to use due diligence in correcting any objectionable conditions. (Louisiana Administrative Code, Title 43, Part 19, §117 (A))

C. Fluid Disposal

1. Produced water generated from the drilling and production of oil and gas wells shall be disposed of into subsurface formations not productive of hydrocarbons, unless discharged or disposed of according to the provisions of §303.E or transported offsite in accordance with LAC 43:XIX, Subpart 1, Chapter 5. (Louisiana Administrative Code, Title 43, Part 19, §303 (A))

2. Produced water may be disposed of by subsurface injection into legally permitted or authorized operators saltwater disposal wells, commercial saltwater disposal wells, enhanced recovery injection wells, community saltwater disposal wells, or gas plant disposal wells. The use of hydrocarbon storage brine and mining water in storage and/or mining operations is not considered to be disposal. (Louisiana Administrative Code, Title 43, Part 19, §303 (B))

3. Produced water and other E&P Waste generated in the drilling and production of oil and gas wells shall not be disposed of into a zone producing or productive of hydrocarbons unless such disposal is approved by the Office of Conservation after a public hearing or unless prior approval to use the proposed zone for such disposal can be documented. (Louisiana Administrative Code, Title 43, Part 19, §303 (D))

Table 2.3 (continued)

4. The discharge of produced water or other E&P Waste (including drilled solids) into manmade or natural drainage or directly into state waters is allowed only in conformance with any applicable state or federal discharge regulatory program. (Louisiana Administrative Code, Title 43, Part 19, §303 (E))

5. No person shall inject, pump, dispose, or in any manner allow the escape of any hazardous waste into any well or underground strata by way of an injection well without obtaining a permit from the assistant secretary or in violation of any permit issued by the assistant secretary; or violate any rule, regulation, or order of the assistant secretary issued under the authority of this Section. (Louisiana Revised Statutes, Title 30, Part 4, §1 (C.1))

6. Valid Coastal Use permits are required for wastewater discharge, including point and nonpoint sources within the coastal zone. (Louisiana Administrative Code, Title 43, Part 1, §723 (A.2.g))
   a. In-Lieu Permits. Coastal use permits shall not be required for the location, drilling, exploration and production of oil, gas, sulfur and other minerals subject to regulation by the Office of Conservation of the Department of Natural Resources as of January 1, 1979. The parameters and procedures of the in-lieu permit process are as provided for under existing Memorandum of Understanding between the Coastal Management Section and the Office of Conservation and the rules and procedures of the Office of Conservation. (Louisiana Administrative Code, Title 43, Part 1, §723 (A.3))

4. Hydraulic Fracturing Operation Requirements

A. Permitting

1. All applications for permits to drill wells for oil or gas or core test wells below the fresh water sands shall be made on Form MD-10-R or revisions thereof, and mailed or delivered to the district office. These applications, in duplicate, shall be accompanied by three copies of the location plat, preferably drawn to a scale of 500 feet to the inch. The plats shall be constructed from data compiled by a registered civil engineer or surveyor and shall definitely show the amount and location of the acreage with reference to quarter-section corners, or other established survey points. There shall also be shown all pertinent lease and property lines, leases and offset wells. When the tract to be drilled is composed of separately-owned interests which have been pooled or unitized, the boundaries to and the acreage in each separately-owned interest must be indicated. Plats must have well locations certifications either written on or attached to the well location plats and this certification must be signed by a registered civil engineer, qualified surveyor or a qualified engineer regularly employed by the applicant. If possible the application card shall give the name and address of the drilling contractor, otherwise the information, as soon as determined, shall be supplied by letter to the district manager. (Louisiana Administrative Code, Title 43, Part 19, §103 (A))

2. When dual completion applications are granted, each well shall be considered as two wells. The production from each sand shall be run through separate lead lines and the production from each sand shall be measurable separately. The department's agent shall designate suitable suffixes to the well number which will serve as reference to each producing sand. (Louisiana Administrative Code, Title 43, Part 19, §103 (B))

3. All applications for permits to repair (except ordinary maintenance operations), abandon (plug and abandon), acidize, deepen, perforate, perforate and squeeze, plug (plug back), plug and perforate, plug back and side-track, plug and squeeze, pull casing, side-track, squeeze, squeeze and perforate, workover, cement casing or liner as workover feature, or when a well is to be killed or directionally drilled, shall be made to the district office on Form MD-11-R and a proper permit shall be received from the district manager before work is started. A description of the work done under the above recited work permits shall be furnished on the reverse side of the Well History and Work Resume Report (Form WH), which form shall be filed with the district office of the Department of Conservation in which the well is located within 20 days after the completion or recompletion of the well. At least 12 hours prior notice of the proposed operations shall be given the district manager and/or an offset operator in order that one of them may witness the work. If the district manager fails to appear within 12 hours, the work may be witnessed by the offset operator, but failing in this, the work need not be held up longer than 12 hours. This rule shall not deter an operator from taking immediate action in an emergency to prevent damage. (Louisiana Administrative Code, Title 43, Part 19, §105 (A))

Table 2.3 (continued)

4. Permit to drill will be issued in accordance with the rules set forth in Louisiana Administrative Code Title 30, Part 28.

5. Valid Coastal Use permits are required for exploration and production of oil or natural gas within the coastal zone. (Louisiana Administrative Code, Title 43, Part 1, §723 (A.2.e))
   a. In-Lieu Permits. Coastal use permits shall not be required for the location, drilling, exploration and production of oil, gas, sulfur and other minerals subject to regulation by the Office of Conservation of the Department of Natural Resources as of January 1, 1979. The parameters and procedures of the in-lieu permit process are as provided for under existing Memorandum of Understanding between the Coastal Management Section and the Office of Conservation and the rules and procedures of the Office of Conservation. (Louisiana Administrative Code, Title 43, Part 1, §723 (A.3))

6. No well shall be drilled, nor shall the drilling of a well be commenced, before a permit for such well has been issued by the Office of Conservation; furthermore, any work, such as digging pits, erecting buildings, derricks, etc., which the operator may do or have done, will be done at his own risk and with the full understanding that the Office of Conservation may find it necessary to change the location or deny the permit because of the rules and regulations applying in that instance.

7. No well shall commence drilling below the surface casing until a sign has been posted on the derrick, and subsequently on the well if it is a producer, showing the operator of record of the well, name of lease, section, township, range, and the serial number under which the permit was issued. The obligation to maintain a legible sign remains until abandonment.

B. Surface Water

1. The commissioner shall promulgate rules, regulations, and orders necessary to require certification of water quality by the operator for surface water used in conjunction with oil and gas drilling operations before drilling begins which ensure ground water aquifer safety. (Louisiana Administrative Code, Title 30, Part 28, (G))

C. Drilling Actions

1. Drilling and production sites shall be prepared, constructed, and operated using the best practical techniques to prevent the release of pollutants or toxic substances into the environment. (Louisiana Administrative Code, Title 43, Part 1, §717 (F))

2. All drilling and production equipment, structures, and storage facilities shall be designed and constructed utilizing best practical techniques to withstand all expectable adverse conditions without releasing pollutants. (Louisiana Administrative Code, Title 43, Part 1, §719 (I))

3. Exploration, production, and refining activities shall, to the maximum extent practicable, be located away from critical wildlife areas and vegetation areas. Mineral operations in wildlife preserves and management areas shall be conducted in strict accordance with the requirements of the wildlife management body. (Louisiana Administrative Code, Title 43, Part 1, §719 (C))

4. Mineral exploration and production sites shall be cleared, revegetated, detoxified, and otherwise restored as near as practicable to their original condition upon termination of operations to the maximum extent practicable. (Louisiana Administrative Code, Title 43, Part 1, §719 (M))

5. Protection
   a. Fencing. Security fencing at least six (6) feet in height shall enclose the wellhead and production facilities. (Office of Conservation-Haynesville Drilling Regulations, Draft (3-A)).

5. Noise and Light Impact Minimization and Mitigation

Table 2.3 (continued)

A. Noise (Office of Conservation-Haynesville Drilling Regulations, Draft (3-I))

1. Prior to commencement of any operation on a well covered by this Order, the operator shall establish a continuous seventy-two (72) hour ambient noise level at the drill site. The seventy-two (72) hour time span shall include at least one twenty-four (24) hour reading during either a Saturday or Sunday. The sound level meter used in conducting noise evaluations shall meet the American National Standard Institute's standard for sound meters or an instrument and the associated recording and analyzing equipment which will provide equivalent data. Documentation of this seventy-two (72) hour ambient noise level shall be maintained by operator and made available to the inspector of the Office of Conservation upon request.

2. No well shall be drilled, or any equipment operated in such a manner so as to create any noise which causes the exterior noise level when measured at a distance of five hundred (500) feet from the well head, or other equipment generating noise, that:
   a. exceeds the seventy-two (72) hour ambient noise level by more than seven (7) decibels during daytime hours or by more than five (5) decibels during nighttime hours;
   b. exceeds the daytime average ambient noise level by more than ten (10) decibels during fracturing or flowback operation; or
   c. exceeds the seventy-two (72) hour ambient noise level by more than five (5) decibels during any flowback operations conducted during nighttime hours.

3. Adjustments to the noise standards as set forth above in subsection 2(a),(b) and (c) of this section may be permitted intermittently in accordance with the following:
   Permitted Increase (dBA)
   Duration of Increase (minutes)*
   10...5
   15...1
   20...less than 1
   *Cumulative minutes during any one hour.

4. The operator shall periodically monitor the exterior noise level at a distance of five hundred (500) feet from the wellhead, or other equipment generating the noise, to ensure compliance with these provisions. If a complaint is received from any person owning an interest in any residence, religious institution, public building or public park located in an urban area and within seven hundred fifty (750) feet from the wellhead, the operator shall, within twenty-four (24) hours of receipt of the complaint, continuously monitor for a seventy-two (72) hour period at a distance of five hundred (500) feet from the wellhead, or other equipment generating the noise, the exterior noise level generated by drilling or other operations to ensure compliance.

5. No compliance order shall be issued by the Office of Conservation for a violation of these noise standards until such time as it has been determined by an Office of Conservation inspector that a violation has occurred and the operator has been given twenty-four (24) hours from receipt of notice of non-compliance to correct the violation. Additional extensions of the twenty-four (24) hour period may be granted by the Office of Conservation in the event that the source of the violation cannot be identified after reasonable diligence by the operator.

B. Lighting

1. To the extent practicable to do so, and recognizing that adequate lighting is essential to conducting drilling, completion and production operations safely and efficiently, site lighting shall be directed downward and internally towards the drill site so as to minimize glare on public roads and adjacent buildings within three hundred (300) feet of the well. (Office of Conservation-Haynesville Drilling Regulations, Draft (3-D))

C. Dust & Odor

1. All drilling, completion and production operations shall be conducted in such a manner so as to minimize, so far as practicable, dust, vibration and noxious odors, and shall be conducted in accordance with generally accepted practices incident to such operations in urban areas. All equipment used in such operations shall be operated in such a manner as to minimize dust, vibration and noxious odors so far as practicable. Proven technological improvements in industry standards of drilling, completion and production in urban areas shall be adopted as they become available if capable of significantly reducing factors of dust, vibration and odor and if economically feasible. (Office of Conservation-Haynesville Drilling Regulations, Draft (3-C))

6. Setbacks

A. Adjacent Wells

1. Wells drilled in search of gas shall not be located closer than 330 feet to any property line nor closer than 2,000 feet to any other well completed in, drilling to, or for which a permit shall have been granted to drill to, the same pool (Louisiana Administrative Code, Title 43, Part 19, §1905 (A.3))

B. Fire Hazards

1. No boiler, open fire, or electric generator shall be operated within 100 feet of any producing oil or gas well, or oil tank (Louisiana Administrative Code, Title 43, Part 19, §115 (B))

2. Each permanent oil tank or battery of tanks that are located within the corporate limits of any city, town or village, or where such tanks are closer than 500 feet to any highway or inhabited dwelling or closer than 1000 feet to any school or church, or where such tanks are so located as to be deemed a hazard by the Commissioner of Conservation, must be surrounded by a dike (or firewall) or retaining wall of at least the capacity of such tank or battery of tanks, with the exception of such areas where such dikes (or firewalls) or retaining walls would be impossible such as in water areas. At the discretion of the Commissioner of Conservation, firewalls of 100 percent capacity can be required where other conditions or circumstances warrant their construction. (Louisiana Administrative Code, Title 43, Part 19, §115 (C))

3. Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least 100 feet from the vicinity of wells, tanks, and pump stations. All waste shall be burned or disposed of in such a manner as to avoid creating a fire hazard or polluting streams and fresh water strata. (Louisiana Administrative Code, Title 43, Part 19, §115 (E))

C. Adjacent Properties

1. Wells drilled in search of gas shall not be located closer than 330 feet to any property line nor closer than 2,000 feet to any other well completed in, drilling to, or for which a permit shall have been granted to drill to, the same pool (Louisiana Administrative Code, Title 43, Part 19, §1905 (A.3))

D. Structures

1. A permit to drill will be approved as long as there are no residential or commercial structures within a 500 ft. radius of the proposed drilling location. ((Louisiana Revised Statutes, Title 30, Part 28, (D))

2. No well shall be drilled less than five hundred (500) feet from any residence, religious institution, public building or public park located in an urban area. The distance shall be calculated from the wellbore, in a straight line, without regard to intervening structures or objects, to the closest exterior point of the building, or to the closest boundary of a public park. (Office of Conservation-Haynesville Drilling Regulations, Draft (2))
   a. Exceptions:
      i. if the owner of the building is a party to an oil, gas and mineral lease covering the property on which the building is located (or successor in interest to the lessor's interest under such lease), then the setback distance from any such building shall be two hundred (200) feet unless otherwise provided in the oil, gas and mineral lease

Table 2.3 (continued)

ii. if the operator obtains the written consent of all owners whose residence, religious institution, public building or public park is located in an urban area and within a five hundred (500) feet radius around the proposed well, then the setback distance from such well shall be two hundred (200) feet. A copy of the written consents shall be filed with the application for the drilling permit to which the consent applies.

E. Highways and Waterways

1. The surface location of all newly proposed wells must be a minimum of 1000 ft from the nearest shoulder of an Interstate Highway crossing of a major water

2. Applicants that receive a drilling permit for a well located within 1,000 feet of an Interstate highway shall furnish a copy of the approved drilling permit and the certified location plat to the appropriate state and local authorities, including all emergency responders.

F. Site Maintenance

1. The drill site and the site of production facilities shall be kept free of standing water, weeds, brush, trash and other waste material; provided, however, that exploration and production waste generated from the drilling of the well may be kept on the drill site until disposed of in accordance with the provisions of Statewide Order No. 29-B. A drill site may not be used for storage of pipe, equipment or other materials which are not intended for use on the well at such site. Neither the drill site, nor the structures thereon, shall be permitted to become dilapidated, unsightly or unsafe.

G. Horizontal Drilling

1. Statewide Order No. 29-E well spacing rules shall not apply to Austin Chalk Formation horizontal wells. The following well spacing rules shall apply to Austin Chalk Formation horizontal wells in areas in which no spacing rules for Austin Chalk Formation horizontal wells have been established by special orders, provided that exceptions may be approved after a public hearing based on 10 days legal notice:
   a. a subsequent Austin Chalk Formation horizontal well shall not be located so as to encroach into a rectangle formed by drawing north-south lines 3,000 feet east of the most easterly point and 3,000 feet west of the most westerly point and east-west lines 100 feet north of the most northerly point and 100 feet south of the most southerly point of any horizontal well completed in, drilling to, or for which a permit shall have been granted to drill to the Austin Chalk Formation. In the case of a single horizontal well, the point of entry into the Austin Chalk Formation (if available) is to be used in lieu of the surface location in determining the northern or southern boundary of the rectangle;
   b. Austin Chalk Formation horizontal well laterals drilled into the same stratigraphic interval from a single wellbore will be treated as a single completion, even if the laterals are isolated by separate producing strings to the surface.

7. Multiple Well Pad Reclamation Practices-None Found, yet.

8. NORM

A. Action Levels:

1. The LDEQ established action levels for NORM, contaminated equipment and land in Section 1404. These are: NORM, NORM waste, and NORM contaminated material (Subsection 1404.A) – greater than 5 pCi/g above background of Ra-226 or Ra-228, or greater than 150 pCi/g or any other NORM radionuclide.

2. Equipment (Subsection 1404.B) – greater than 50 uR/hr at any accessible point.

3. Land (Subsection 1404.C) Averaged over any 100 square meters with no single noncomposited sample to exceed 60 pCi/g of soil:
   a. • Greater than 5 pCi/g above background of Ra-226 or Ra-228, averaged over the first 15 cm, and 15 pCi/g above background over each subsequent 15 cm; or

Table 2.3 (continued)

b. • Greater than 30 pCi/g of Ra-226 or Ra-228, averaged over 15 cm depth increments, provided the total effective dose equivalent from the contaminated land does not exceed 0.1 rem/year.

4. The Section 1404 also includes certain exemptions from the NORM regulations.
   a. The recycling of NORM contaminated equipment: potassium and potassium compounds that have not been isotopically enriched in the radionuclide K-40; 2. materials used for building construction, industrial processes, metal casings, and abrasive cleaning if the NORM content of such material has not been technologically enhanced; and 3. byproducts from fossil fuel combustion (bottom ash, fly ash, and flue-gas emission control byproducts).
   b. The wholesale and retail distribution of natural gas and natural gas products
   c. Produced waters from crude oil and natural gas production are exempt from the requirements of these regulations. Regulations concerning produced waters are referenced in LAC 33:IX.Chapter 7.
   d. Tanks, vessels, containers, storage facilities, and distribution lines in refineries and petrochemical and gas plants contaminated with regulated NORM

(Louisiana State Review of Oil and Natural Gas Enviromental Regulations, Inc. §7.3.2)

B. Survey: The LDEQ required initial surveys on all potentially contaminated sites (Section 1407). Follow-up confirmatory surveys shall be performed whenever activities at the site could result in a possible change in regulatory status of the site. Any survey submitted to LDEQ must include the qualifications of the individual performing the survey. (Louisiana State Review of Oil and Natural Gas Enviromental Regulations, Inc. §7.3.3)

C. Worker Protection: site maintenance by NORM general licensees is allowed only if the maximum radiation level does not exceed two millirem per hour. (Louisiana State Review of Oil and Natural Gas Enviromental Regulations, Inc. §7.3.4)

D. The LDEQ issues a general license to mine, extract, receive, possess, own, use, store, and transfer NORM (Subsection 1408.A). General licensees are usually oil and natural gas operators. (Louisiana State Review of Oil and Natural Gas Enviromental Regulations, Inc. §7.3.5)

E. LDEQ allows a general licensee to store NORM waste in a container for up to 90 days from generation (Subsection 1408.A.6), and if the licensee first submits a written NORM waste management plan, allows for storage for up to 365 days from generation. (Louisiana State Review of Oil and Natural Gas Enviromental Regulations, Inc. §7.3.7)

F. Release of Sites, Materials and Equipment (Section 7.3.9)

1. Once facilities, equipment, or sites exceed the level of contamination in LAC 33:XV §1404, they shall not be released for unrestricted use until they have been decontaminated in accordance with Section 1417. For general or specific licensees that have an area or soil with contamination above the limits of Section 1404, soil decontamination must be performed. The decontamination of soil shall be to 5 picocuries per gram above background of radium-226 or radium-228. For general or specific licensees who have equipment with a maximum exposure level above that specified in Section 1404, equipment decontamination must be performed to reduce the exposure levels below those specified in Section 1404 and to ensure that the equipment is free of loose contamination. In all other cases, the decontamination shall reduce radiation levels below the exemption levels provided in Section 1404. Unless otherwise directed in writing by the LDEQ, a licensee shall submit a plan for the decontamination to the LDEQ for approval to release property for unrestricted use. Upon approval, the licensee shall implement the plan in accordance with such approval. (Louisiana State Review of Oil and Natural Gas Enviromental Regulations, Inc. §7.3.9)

G. Disposal (Louisiana State Review of Oil and Natural Gas Enviromental Regulations, Inc. §7.3.10)

1. The LDEQ in Section 1412 provides for the treatment and disposal of NORM wastes in accordance with the following:
   a. • By transfer of the wastes to a land disposal facility licensed by LDEQ, the NRC, an agreement state, or a licensing state;
   b. • By alternate methods authorized by LDEQ in writing upon application or upon LDEQ's initiative. An example of an alternate method is the placement of NORM in a well to be plugged and abandoned.

Table 2.3 (continued)

c. • For E&P waste containing NORM at concentrations not exceeding 30 pc/g Ra-226 or Ra-228 by transfer to an E&P waste commercial facility regulated by the DNR for treatment if certain conditions are met by the facility.

d. • For E&P waste containing concentrations of NORM in excess of the limits in Subsection 1404.A.1, but not exceeding 200 pC/g Ra-226 or Ra-228 and daughter products, by treatment at E&P waste commercial facilities specifically licensed by LDEQ for such purposes.

H.

9. Storm Water Runoff

A. Storm Water Discharge Permitting

1. Oil & gas exploration, development, and production facilities desiring authorization to discharge under General Permit No. LAG330000/AI 101080 must submit a written Notice of Intent (NOI) by using form CWOGF-G. Upon correct completion and submittal of a NOI to the Office of Environmental Services, such persons will become permittees and will be authorized to discharge under this general permit after 14 calendar days of a hand delivered NOI to LDEQ or after the postmark date. (Louisiana Department of Environmental Quality, General Permit No. LAG330000, Letter to Interested Parties from the LDEQ, 2005)

2. Covered Discharges under Permit No. LAG330000/AI101080
   a. Dewatering effluents from reserve pits which have not received drilling fluids and/or drill cuttings since 12/15/1996, deck drainage, formation test fluids, sanitary wastewater, domestic wastewater, hydrostatic test water, and miscellaneous discharges which are common to the Coastal Subcategory of the Oil and Gas Extraction Point Source Category (40 CFR part 435, Subpart D) classified under the Standard Industrial Classification (SIC) 1311. (LDEQ Permit No. LAG330000, Part I.A.1)
   b. Permit LAG330000 does not cover discharges from "Major" facilities in the LPDES system; discharges mixed with non-covered discharge types unless they are in compliance with another permit; substances that are not adequately detected by the effluent limitations in this permit, including Organic Toxic Pollutants, Other Toxic Pollutants (Metals and Cyanide) and Total Phenols, and Toxic Pollutants and Hazardous Substances listed in Appendix D of LAC 33:IX.325; waste water discharges with limitations from the Louisiana Water Quality Management Plan or an approved Waste Load Allocation that are different from this permit; wastewater discharges that adversely effect properties listed in the National Register of Historical Places, unless in compliance with the National Historic Preservation Act; wastewater determined to present an environmental risk of discharging pollutants that are not regulated by this permit; discharges from decontamination of equipment; discharge associated with disposal storage, or treatment of hazardous oil-field waste; drilling fluids or cuttings; produced water or sands; well treatment, completion, and workover fluids; and discharges that contribute to the violation of state water quality standards. (LDEQ Permit No. LAG330000, Part I.A.2)

3. Discharges to water bodies of the state are to maintain state water quality standards (LDEQ Permit No. LAG330000, Part II.F)

4. Monitoring and Records (Louisiana Administrative Code Title 33:IX.2701.J)
   a. 1. Samples and measurements of discharge waters from the dewatering effluent from reserve pits, hydrostatic test waters, and miscellaneous discharges taken for the purpose of monitoring shall be representative of the monitored activity. (LDEQ Permit No. LAG330000, Part I.B)
   b. 2. Except for records of monitoring information required by this permit related to the permittee's sewage sludge use and disposal activities, which shall be retained for a period of at least five years (or longer as required by 40 CFR Part 503), the permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least three years from the date of the sample, measurement, report or application. This period may be extended by request of the state administrative authority at any time.
   c. 3. Records of monitoring information shall include:

Table 2.3 (continued)

i. a. the date, exact place, and time of sampling or measurements;
ii. b. the individual(s) who performed the sampling or measurements;
iii. c. the date(s) analyses were performed;
iv. d. the individual(s) who performed the analyses;
v. e. the analytical techniques or methods used;
vi. f. the results of such analyses; and
vii. g. additional information found in LAC 33:IX.6515.

d. 4. Monitoring results must be conducted according to test procedures approved under 40 CFR Part 136 (see LAC 33:IX.4901) or, in the case of sludge use or disposal, approved under 40 CFR Part 136 (see LAC 33:IX.4901) unless otherwise specified in 40 CFR Part 503, unless other test procedures have been specified in this permit.

e. 5. R.S. 30:2025 provides for the punishment of any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit.

5. Discharge Limitations (MQLs) (LDEQ Permit No. LAG330000, Part II.L)
   a. Total Pb ≤ 5 μg/l, Total Cr, Cr^{3+} & Cr^{6+} ≤ 10 μg/l, and Total Zn ≤ 20 μg/l
   b. Benzene, Ethylbenzene, Toluene and Xylene ≤ 10 μg/l

6. Operators that have independent oil and gas wells that tie into another operator's permitted production facility can be automatically covered provided that the operator of the permitted production facility agrees to allow the discharges from those wells to be covered under the permitted facility's permit. (LDEQ Permit No. LAG330000, Part I.A.2)

7. Should a reportable quantity release of oil or a hazardous substance in stormwater occur at a permitted production facility or independent well, the operator must prepare and implement a Storm Water Pollution Prevention Plan within 60 days. This may incorporate Spill Prevention Control and Countermeasure Plan, Best Management Plan, and Response Plans. (LDEQ Permit No. LAG330000, Part I.A.2, and Part II.M.3)

8. Operators must notify the Office of Environmental Services, Water and Waste Permits Division as soon as they know or have reason to believe:
   a. That any activity has occurred resulting in the discharge, on a routine or frequent basis, any pollutant in LAC 33.IX.7107, Tables II and III (excluding Total Phenols) exceed the highest of the following levels:
      i. 100 μg/L;
      ii. 200 μg/L for acrolein & acrylonitrile; 500 μg/l for 2,4-dinitro-phenol and 2-methyl-4,6-dinitrophenol; and 1 mg/l for Sb;
      iii. 5 times the maximum concentration value for that pollutant in the permit application, or
      iv. The level established by the state administrative authority in accordance with LAC 33:IX.2707.F
   b. That any activity has occurred resulting in the discharge, on a non-routine or infrequent basis, any pollutant in LAC 33.IX.7107, Tables II and III (excluding Total Phenols) exceed the highest of the following levels:
      i. 500 μg/L;
      ii. 1 mg/L Sb;
      iii. 10 times the maximum concentration value for that pollutant in the permit application, or
      iv. The level established by the state administrative authority in accordance with LAC 33:IX.2707.F

   (LDEQ Permit No. 330000, Part III.D.9)

B. Construction Requirements for Areas of Disturbance greater than 1 acre and less than 5 acres

1. Construction activities related to oil and gas exploration, production, processing, or treatment, or transmission activities are exempt from regulation. Section 323 of the Environmental Policy Act of 2005 modified paragraph (24) of Section 502 of the Clean Water Act (CWA) to define the term "oil and gas, exploration, production, processing, or treatment, or transmission facilities." This term is used in CWA Section 402(1)(2) to identify oil and gas activities for which the Environmental Protection Agency (EPA) shall not require National Pollutant Discharge Elimination System (NPDES) permit coverage for certain storm water discharges. The effect of this statutory change is to make construction activities at oil and gas sites eligible for the exemption established by CWA Section 402(1)(2). The exemption from obtaining LPDES permit coverage for stormwater discharges from construction activities at these oil and gas sites is codified in the Environmental Regulatory Code at LAC

Table 2.3 (continued)

33:IX.2511.A.2. All construction activities are exempt, regardless of the amount of disturbed acreage, which are necessary to prepare a site for drilling and the movement and placement of drilling equipment, constructing access roads, drilling waste management pits, in field treatment plants and the transportation infrastructure (e.g., crude oil and natural gas pipelines, natural gas treatment plants and both natural gas transmission pipeline compressor and oil pumping stations) necessary for the operation of most producing oil and gas fields. (LDEQ, Permit No. LAR200000, Part I.A)

C. Surface Runoff

1. Reserve Pits shall be protected from surface waters by levees or walls and by drainage ditches, where needed, and no siphons or openings will be placed in or over levees or walls that would permit escaping of contents so as to cause pollution or contamination. Authorized surface discharges of pit contents under federal or state regulatory programs are not considered to be pollution or contamination as used herein. (Louisiana Administrative Code, Title 43, Part 19, §307 (B))

2. Runoff from developed areas shall to the maximum extent practicable be managed to simulate natural water patterns, quantity, quality, and rate of flow. (Louisiana Administrative Code, Title 43, Part 1, §717 (B))

3. Mineral exploration and production facilities shall be to the maximum extent practicable designed, constructed, and maintained in such a manner to maintain natural water flow regimes, avoid blocking surface drainage, and avoid erosion. (Louisiana Administrative Code, Title 43, Part 1, §719 (D))

4. The discharge of drill cuttings or drilling fluids, including stormwater runoff contaminated by drill cuttings or drilling fluids, must be conducted in accordance with a valid LWDPS permit. There shall be no discharge of oil-based drilling fluids. (LAC Title 33:IX. §708.3.a-b)

5. Stormwater Discharges (LDEQ Permit No. LAG330000, Part II.M)
   a. In accordance with LAC 33:IX.708.C.4, any runoff leaving the developed areas of the facility, other than permitted outfall(s), exceeding 100 mg/l COD, 50 mg/L TOC, 15 mg/L Oil and Grease, having a pH <6 or >9 s.u., Cl concentration twice the ambient concentration of the receiving water in brackish marsh or 500 mg/L in freshwater or intermediate marsh areas and upland areas are in violation of Permit LAG330000.
   b. All site equipment and facilities shall be maintained in such a way as to prevent the contamination of stormwater by pollutants

Table 2.4
New Mexico Regulatory Survey

Agency: New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division; http://www.emnrd.state.nm.us/ocd/index.htm (unless otherwise noted)

Regulations, Acts, and Laws:

- Oil and Gas Act, NMSA 1978, Sections 70-2-1through 70-2-38
- The Oil and Gas (O&G) Act (P.L. 1140, No. 223) (58 P.S. Section 601.101 et seq.)
- Coal and Gas Resource Coordination Act (P.L. 1069, No. 214) (58 P.S. Section 501.1 et seq.)
- Oil and Gas Conservation Law (P.L. 825, No. 359) (58 P.S. Section 401.1 et seq.)
- The Clean Streams (CS) Law (P.L. 1987, No.394) (35 P.S. Section 691.1 et seq.)
- Solid Waste Management Act (SWA) (P.L. 380, No. 97) (35 P.S. Section 6018.101 et seq.)
- New Mexico Administrative Code (NMAC), Title 19 Natural Resources and Wildlife, Chapter 15 Oil and Gas (19.15 NMAC)

1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

References:

New Mexico Energy, Minerals, and Natural Resources Department, Oil Conservation Division; 19.15.17 NMAC Pits, Closed-Loop Systems, Below-Grade Tanks and Sumps; 6/4/2009. http://www.emnrd.state.nm.us/ocd/documents/20091-1CurrentRules.pdf

A. Regulations

- New Mexico Administrative Code (NMAC), Title 19 Natural Resources and Wildlife, Chapter 15 Oil and Gas, Part 17 Pits, Closed-Loop Systems, Below-Grade Tanks & Sumps (19.15.17 NMAC)

Note: Rule 19.15.17 NMAC, commonly referred to as "The Pit Rule," is currently going through an amendment process. The proposed changes can be found at: http://www.emnrd.state.nm.us/ocd/documents/Application030209WebPosting.pdf

- 19.15.17.8 NMAC – Permit Required
- 19.15.17.10 NMAC - Siting Requirements
- 19.15.17.11 NMAC - Design and Construction Specifications
- 19.15.17.12 NMAC - Operational Requirements
- 19.15.17.13 NMAC - Closure Requirements: **A.** Time requirements for closure. An operator shall close a pit, closed-loop system or below-grade tank within the time periods provided in 19.15.17.13 NMAC, or by an earlier date that the division requires because of imminent danger to fresh water, public health or the environment.

B. Tank Requirement: None.

Table 2.4 (continued)

An operator may use a closed-loop system with tanks or other OCD-approved alternative method, provided the operator has a permit for a closed-loop system (19.15.17.8B NMAC)

C. Pit and Below-Grade Tank Siting and Access Prevention Criteria

1. Location / Setbacks (19.15.17.10 NMAC Siting Requirements):

   a. Pit (except Emergency Pits) or Below-Grade Tank:

      i. pit or tank bottom must be > 50 feet above ground water

      ii. > 300 feet away from continuously flowing watercourses, or 200 feet from any other significant watercourse or lakebed, sinkhole, or playa lake (measured from the ordinary high-water mark)

      Exception: with appropriate OCD approval (see rule), based upon the operator's demonstration that surface and ground water will be protected

      iii. > 300 feet (temp. pit or below-grade tank) or > 1000 feet (perm. pit) away from a permanent residence, school, hospital, institution or church in existence at the time of initial application

      iv. > 500 feet from private, domestic fresh water wells or springs used by less than five households for domestic or stock watering purposes

      v. > 1000 feet from any other fresh water well or spring, in existence at the time of initial application

      vi. not within incorporated municipal boundaries, unless the municipality approves

      vii. not within a defined municipal fresh water well field covered under a municipal ordinance adopted pursuant to NMSA 1978, Section 3-27-3, as amended, unless the municipality approves

      viii. > 500 feet from wetlands

      ix. not within an area overlying a subsurface mine

      Exception: with appropriate OCD approval (see rule), based upon the operator's demonstration that the pit's or tank's construction and use will not compromise the subsurface integrity

      x. not within an unstable area, unless the operator demonstrates that it has incorporated engineering measures into the design to ensure that the pit's or tank's integrity is not compromised

      xi. not within a 100-year floodplain.

   b. Emergency Pits: Exempt from the siting criteria of 19.15.17 NMAC.

2. Access Prevention / Safety: Pits and Tanks (19.15.17.11 NMAC Design and Construction Specifications)

   a. Fencing (with a sign including the operator's name, the site location, and emergency phone numbers):

      i. Pits or below-grade tanks must be enclosed to prevent unauthorized / accidental access. The enclosures must be maintained. A perimeter fence that prevents unauthorized access to the well site or facility, including the pit or below-grade tank, is adequate. During drilling or workover operations, the edge of the pit adjacent to the rig does not have to be fenced.

      ii. If the pit or tank is </= 1000 feet of a permanent residence, school, hospital, institution or church, a chain link security fence, at least six feet in height with at least two strands of barbed wire at the top, is required. All fence gates must be closed and locked when responsible personnel are not on-site. During drilling or workover operations, the edge of the pit adjacent to the rig does not have to be fenced.

iii. Any other pit or below-grade tank shall be fenced to exclude livestock using a four foot fence with at least four strands of barbed wire evenly spaced in the interval between one foot and four feet above ground level.

Exceptions: An OCD-approved alternative may be used if the operator demonstrates it provides equivalent or better protection. The appropriate division district office may impose additional fencing requirements in particular areas.

b. Netting: All permanent pits and permanent open-top tanks must be screened, netted or otherwise rendered non-hazardous to wildlife. Where netting or screening is not feasible, pits and tanks must be inspected monthly for dead wildlife. Dead wildlife discovery must be reported to the appropriate wildlife agency and to the appropriate OCD district office.

D. Pit Construction Specifications (19.15.17.11 NMAC Design and Construction Specifications & 19.15.17.10 NMAC Siting Requirements)

1. Temporary Pits

a. Volume: </= 10 acre-feet, including freeboard.

b. Freeboard: 2 feet (19.15.17.12 NMAC Operational Requirements)

c. Depth of Bottom: pit or tank bottom must be > 50 feet above ground water

d. Subbase / Subgrade: foundation and interior slopes must consist of a firm, unyielding base, smooth and free of rocks, debris, sharp edges or irregularities. Geotextile is required under the liner where needed to reduce localized stress-strain or protuberances that may otherwise compromise the liner’s integrity.

e. Slopes: no steeper than two horizontal feet to one vertical foot (2H:1V) or OCD-approved alternative

f. Surface Water Diversion: berm, ditch, proper sloping or other diversion to prevent surface water run-on. During drilling and workover operations, the edge of the temporary pit adjacent to the rig is not required to have run-on protection if the pit is used to collect liquids escaping from the rig and run-on will not result in a breach of the temporary pit.

g. Liner Protection: The liner must be protected from any fluid force or mechanical damage at any point of discharge into or suction from the lined temporary pit.

h. Flare Area: The part of a pit used to vent or flare gas during a drilling or workover operation that is designed to allow liquids to drain to a separate temporary pit does not require a liner, unless the OCD requires an alternative design to protect surface and ground water and the environment.

i. Liner Anchor: Edges of all liners must be anchored in the bottom of a compacted earth-filled trench at least 18 inches deep.

2. Permanent Pits

a. Volume: </= 10 acre-feet, including freeboard.

b. Freeboard: 3 feet

c. Depth of Bottom: pit or tank bottom must be > 50 feet above ground water

d. Subbase / Subgrade: foundation must be firm, unyielding, smooth and free of rocks, debris, sharp edges or irregularities.

e. Levee:

Table 2.4 (continued)

- Inside slope: no steeper than 2 horizontal feet to 1 vertical foot
- Outside slope: no steeper than 3 horizontal feet to 1 vertical foot
- Top: wide enough to install an anchor trench and provide adequate room for inspection and maintenance.

f. Surface Water Diversion: berm, ditch, or other diversion to prevent run-on of surface water

g. Liner Protection: At a point of discharge into or suction from the lined permanent pit, the operator shall ensure that the liner is protected from excessive hydrostatic force or mechanical damage. External discharge or suction lines shall not penetrate the liner.

h. Leak Detection System: required; between upper and lower liners

- two feet of compacted soil with a saturated hydraulic conductivity >/= 1 x 10^{-5} cm/sec
- drainage and collection and removal system
- slope: at least 2% grade (2 vertical feet per 100 horizontal feet)
- piping: solid and perforated; diameter >/= 4 inches; >/= 80 schedule; must withstand chemical attack from oil field waste or leachate, structural loading from overlying waste, cover, equipment operation and expansion and contraction
- riser pipe: solid; conveys collected fluids to a collection, observation and disposal system
- collection, observation, and disposal system outside the pit's perimeter
- alternative methods with OCD environmental bureau approval

E. Pit / Impoundment Liner Specifications (19.15.17.11 NMAC Design and Construction Specifications)

1. Temporary Pit (1 liner):

a. Coefficient of Permeability: No information found.

b. Thickness / Strength: 20 mils

c. Composition: string-reinforced LLDPE or OCD-approved equivalent material that is impervious, synthetic, resistant to petroleum hydrocarbons, salts, acidic and alkaline solutions, and ultraviolet light. Liner compatibility shall comply with EPA SW-846 method 9090A.

d. Seams: minimized, oriented parallel to the maximum slope, factory-welded where possible; no horizontal seams within 5 feet of the slope's toe

Field seams: liners must overlap four to six inches, only located in corners and irregularly shaped areas when unavoidable, thermally sealed with a double-track weld for nondestructive air channel testing, tested with 33-37 psi with an acceptable change of </= 1% 5 minutes after the pressure source is turned off

2. Permanent Pit (2 liners):

a. Coefficient of Permeability: </= 1 x 10^{-9} cm/sec

b. Thickness / Strength: 30-mil PVC or 60-mil HDPE

c. Composition: flexible PVC or HDPE geomembrane, or an equivalent liner material approved by the OCD's environmental bureau that is impervious, synthetic, resistant to petroleum hydrocarbons, salts,

Table 2.4 (continued)

acidic and alkaline solutions, and ultraviolet light. Liner compatibility shall comply with EPA SW-846 method 9090A.

d. Seams: minimized, oriented parallel to the maximum slope, factory-welded where possible

Field seams: liners must overlap four to six inches, only located in corners and irregularly shaped areas when unavoidable, welded

F. Land Application Specifications – No information found.

G. Pit and Waste Removal and Disposal Time Limits (19.15.17.13 NMAC)

a. Permanent Pit: within 60 days of cessation of operation of the pit in accordance with a OCD environmental bureau approved closure plan

b. Temporary Pit: All free liquids (all contents) must be removed from a temporary pit within 30 days of the date that the rig is released (19.15.17.12 NMAC). The liquids must be disposed of in an OCD-approved facility or recycled, reused or reclaimed in a manner of which the OCD approves (19.15.17.12 NMAC).The pit must be closed or removed within 6 months of the same date. The OCD may grant an extension, not to exceed three months (19.15.17.13 NMAC).

H. Requirements for Onsite Closure Methods for Temporary Pits

1. Site must comply with the siting criteria in subsection C.1.a of this section, Section 1.

2. The ground water must be at least 50 feet below the pit bottom

3. If the ground water is 50 - 100 feet below the bottom of the buried waste, the waste must be treated or stabilized and combined with soil or other material at a mixing ratio of at least 3 parts soil or other material to one part waste, buried in place, and the contaminant concentrations fall within the limits outlined in subsection E.1.c.i of this section, Section 1.

4. If the ground water is more than 100 feet below the bottom of the buried waste, the waste must be treated or stabilized and combined with soil or other material at a mixing ratio of at least 3 parts soil or other material to one part waste, buried in place, and the contaminant concentrations fall within the limits outlined in subsection E.1.c.i of this section, Section 1.

5. Surface owner must be notified.

I. Pit Closure

1. Temporary Pits

a. remove all liquids from the temporary pit

b. dispose of the liquids in an OCD-approved facility or recycle, reuse or reclaim the liquids in an OCD-approved manner.

c. Closure Methods

i. Waste Excavation and Removal

- Excavate all contents and synthetic pit liners.
- Transfer materials to an OCD-approved facility.

Table 2.4 (continued)

- Collect, at a minimum, a five-point, composite sample from the soils beneath the pit; collect individual grab samples from any area that is wet, discolored or showing other evidence of a release.
- Analyze for benzene, total BTEX, TPH, the GRO and DRO combined fraction and chlorides
- Limits:
  - If the ground water is > 50 feet below the bottom of the pit:
    - Benzene (EPA SW-846 method 8021B or 8260B) </= 0.2 mg/kg
    - Total BTEX (EPA SW-846 method 8021B or 8260B) </= 50 mg/kg
    - TPH (EPA SW-846 method 418.1) </= 2500 mg/kg
    - GRO and DRO combined fraction (SW-846 method 8015M) </= 500 mg/kg
  - If the ground water is between 50 and 100 feet below the bottom of the pit:
    - Chlorides (EPA 300.1) </= the greater of 500 mg/kg or background conc.
    - If the ground water is more than 100 feet below the bottom of the pit:
    - Chlorides (EPA 300.1) </= the greater of 1000 mg/kg or background conc.
- If a release has occurred, comply with 19.15.29 NMAC and 19.15.30 NMAC, as appropriate.
- If a release has not occurred or any release does not exceed the concentrations above, backfill the pit excavation with compacted, non-waste containing, earthen material and reclaim the disturbed area.

i. On-site Burial: comply with the siting requirements in Subsections H and E of this section and the closure requirements and standards of Subsection F of 19.15.17.13 NMAC.

ii. Alternative closure methods: must be OCD-approved.

2. Permanent Pits

a. Remove all liquids and basic sediment & water.

b. Dispose of the liquids and BS&W in an OCD-approved facility.

c. Remove the pit liner system, if applicable, and dispose of it in an OCD-approved facility.

d. Remove onsite equipment associated with the pit unless the it is required for some other purpose.

e. Collect, at a minimum, a five-point, composite sample from the soils beneath the pit; collect individual grab samples from any area that is wet, discolored or showing other evidence of a release.

f. Analyze for benzene, total BTEX, TPH, and chlorides.

g. Limits:

i. Benzene (EPA SW-846 method 8021B or 8260B) </= 0.2 mg/kg

ii. Total BTEX (EPA SW-846 method 8021B or 8260B) </= 50 mg/kg

iii. TPH (EPA SW-846 method 418.1) </= 100 mg/kg

iv. Chlorides (EPA 300.1) </= the greater of 250 mg/kg or background conc.

Table 2.4 (continued)

h. If a release has occurred, then the operator shall comply with 19.15.29 NMAC and 19.15.30 NMAC, as appropriate.

i. If a release has not occurred or any release does not exceed the concentrations above, backfill the excavation with compacted, non-waste containing, earthen material, and reclaim the disturbed area.

J. Reclamation of Disposal Area (19.15.17.13 NMAC):

1. General: Reclamation begins once a pit or other disposal area is closed or an area associated with the disposal area, including access roads, is no longer in use.

2. Cover:

   a. Thickness:

      i. closures where a pit's contents have been removed or contaminated soil has been remediated – The thickness must be at least the background thickness of the topsoil or one foot of suitable material to establish vegetation at the site, whichever is greater

      ii. burial-in-place or trench burial – The thickness must be a minimum of four feet of compacted, non-waste containing, earthen material PLUS soil cover as thick as the background thickness of topsoil or one foot of suitable material to establish vegetation at the site, whichever is greater.

   b. Grading: The soil cover must be constructed to the site's existing grade and be graded to prevent ponding of water and erosion of the cover material.

   c. Recontouring: The location and associated areas must be contoured to approximates the original contour and blend with the surrounding topography.

3. Revegetation

   a. Seeding or planting of the disposal area and any disturbed area associated with the disposal area and no longer in use, including access roads, must occur during the first growing season after the closure of a pit or trench.

   b. **S**eeding should be accomplished by drilling on the contour wherever practical or by other OCD-approved methods. Vegetative cover must equal 70% of the native perennial vegetative cover (un-impacted by overgrazing, fire or other intrusion damaging to native vegetation) and consist of at least three native plant species, including at least one grass, but not including noxious weeds. The cover must be maintained through two successive growing seasons. There can be no artificial irrigation during the two seasons that prove viability.

   c. Repeat seeding or planting is required until the vegetative cover is viable.

   d. With OCD approval, seeding and/or planting may be delayed when conditions are not favorable for the establishment of vegetation. The OCD may require the use of additional mulching, fertilizing, irrigating, fencing or other practices.

   e. The OCD must be notified when seeding and/or planting is complete and again when revegetation has been achieved.

   f. The operator may propose an alternative to revegetation if the proposed alternative prevents erosion; protects fresh water, human health, and the environment; and is approved by the surface owner and the OCD.

2. Water Well Testing Requirements – No information found.

Table 2.4 (continued)

3. Fracturing Fluid Requirements and Fluid Use and Recycling – No information found.

4. Hydraulic Fracturing Operation Requirements

Reference: New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, 6/5/2009; http://www.emnrd.state.nm.us/ocd/Forms.htm.

A. form C-101 - application for permit to drill, deepen or plug back;

B. form C-102 - well location and acreage dedication plat;

C. form C-103 - sundry notices and reports on wells;

D. form C-105 - well completion or recompletion report and log;

E. form C-107 - application for multiple completion;

F. form C-109 - application for discovery allowable and creation of a new pool;

G. form C-117- A - tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit;

H. form C-122 - multi-point and one point back pressure test for gas wells;

I. form C-122- B - initial potential test data sheet;

J. form C-123 - request for the creation of a new pool;

K. form C-124 - reservoir pressure report;

L. form C-129 - application for exception to no-flare;

M. form C-133 - authorization to move produced water exhibit “A”;

N. form C-137 - application for waste management facility;

O. form C-139 - application for qualification of production restoration project and certification of approval;

P. form C-140 - application for qualification of well workover project and certification of approval;

Q. form C-141 - release notification and corrective action;

R. form C-144 - pit, closed-loop system, below-grade tank or proposed alternative method permit or closure plan application;

5. Noise and Light Impact Minimization and Mitigation – No information found.

6. Setbacks – No information found (only lease boundary, etc. setbacks)

7. Multiple Well Pad Reclamation Practices

Table 2.4 (continued)

References: New Mexico Administrative Code (NMAC), Title 19 Natural Resources and Wildlife, Chapter 15 Oil and Gas, Part 18 Production Operating Practices, Rule 10 Control of Multiple Completed Wells (19.15.18.10 NMAC), 6/6/2009; http://www.emnrd.state.nm.us/ocd/documents/20091-1CurrentRules.pdf

There are no rules that specifically regulate the reclamation of multiple well pads. No information was found regarding typical reclamation practices, guidelines or permit issues that are unique to multiple well pads.

8. Naturally Occurring Radioactive Material (NORM)

Agencies:

NMEMNRD, OCD

New Mexico Environmental Department (NMED), Radiation Licensing and Registration Section

NMED, Environmental Improvement Board

References:

New Mexico Energy, Minerals, and Natural Resources Department, Oil Conservation Division; 19.15.9.714 NMAC Disposal of Regulated Naturally Occurring Radioactive Material (Regulated NORM); 6/6/2009. http://www.emnrd.state.nm.us/ocd/documents/RULEBOOK2008-06-16_002.pdf

New Mexico Environment Department

E. Regulations

- New Mexico Administrative Code (NMAC), Title 19 Natural Resources and Wildlife, Chapter 15 Oil and Gas, Part 9 Well Operator Provisions, Rule 714 Disposal of Regulated NORM (19.15.9.714 NMAC):

  19.15.1.2 SCOPE: These rules apply to all persons/entities engaged in oil and gas development and production within New Mexico.

  A. Purpose. This rule establishes procedures for the disposal of regulated naturally occurring radioactive material (Regulated NORM) associated with the oil and gas industry. Any person disposing of Regulated NORM, as defined at 19 NMAC 15.A.7, is subject to this rule and to the New Mexico environmental improvement board regulations at 20 NMAC 3.1, Subpart 14.

- New Mexico Administrative Code (NMAC), Title 20 Environmental Protection, Chapter 3 Radiation Protection, Part 14 NORMs in the Oil and Gas Industry (20.3.14):

  20.3.14.2 SCOPE: These rules apply to

  A. any person who engages in the extraction, transfer, transport, storage or disposal of NORM, or in the enhancement of NORM, in the oil and gas industry by altering the chemical properties, physical state or concentration of the NORM or its potential exposure pathways to humans.
  B. sludges and scale deposits in tubulars and equipment and to scale deposits from cleaning added to the environment.
  C. NORM deposits in soil, water and the environment unless otherwise regulated.
  D. Regulated NORM management, transfer, storage, and disposal with regard to facilities involved in storage and/or cleaning of tubulars and equipment.

  20.3.14.1403 EXEMPTIONS:

  A. For release for unrestricted use, persons who receive, possess, use, process, transfer, distribute, transport, store or dispose of NORM are exempt from the requirements of these regulations if: the NORM present is at concentrations of 30 picocuries per gram or less of radium 226, above background, or 150 picocuries per gram or less of any other NORM radionuclide, above background, in soil, in 15 cm layers, averaged over 100 square meters. Samples should be taken if gamma radiation readings (mR/hr) are equal to or exceed twice background readings when surveyed at a distance of 1 cm from the surface of the soil, in accordance with Department guidelines.

B. The possession and use of natural gas and natural gas products and crude oil and crude oil products as fuels are exempt from the requirements of this Subpart [Part].

C. NORM not otherwise exempted and equipment from oil, gas, and water production containing NORM are exempt from the requirements of this Subpart if the maximum radiation exposure reading at any accessible point does not exceed 50 microroentgens per hour (mR/hr) (0.5 mSv/hr), including background radiation levels. Sludges and scales contained in oil, gas and water production equipment are exempt from the requirements of this Subpart if the maximum radiation exposure reading within 1 cm of the surface of the sludge or scale does not exceed 50 microroentgens per hour (50 mR/hr) (0.5 mSv/hr), including background radiation levels. If the radiation readings exceed 50 mR/hr (0.5 mSv/hr), removable sludges and scales are exempt from the requirements of these regulations if the concentration of Radium 226, in a representative sample, does not exceed 30 picocuries per gram.

D. NORM not otherwise exempted and equipment from gas processing, fractionation, and dry gas distribution containing NORM are exempt from the requirements of this Subpart [Part] if the removable surface NORM contamination does not exceed 1000 dpm/100 cm2 and otherwise conforms with the requirements of 1403.A [Subsection A., Section 1403 of 20.3.14.1403 NMAC]. Removable scale from gas processing fractionating, and dry gas distribution is exempt from the requirements of this Subpart [Part] if the concentration of Lead 210, in a representative sample, does not exceed 150 picocuries per gram.

E. Produced water is exempt from the requirements of these regulations if it is reinjected into a Class I or Class II Underground Injection Control (UIC) well permitted by the Division and/or stored or disposed in a double, synthetically lined surface impoundment permitted by the Division.

9. Storm Water Runoff Best Management Practices

Agency: NMEMNRD, OCD

References:

- NMEMNRD OCD, 2000. Pollution Prevention Best Management Practices for the New Mexico Oil and Gas Industry
- NMEMNRD OCD, 1999. Pollution Prevention/Best Management Practices Pocket Guide for the New Mexico Oil and Gas Industry

- Waste Disposal: All wastes must be disposed of at an OCD approved facility. Only oilfield exempt wastes may be disposed of down Class II injection wells. Non-exempt oilfield wastes that are non-hazardous may be disposed of at an OCD-approved facility upon proper waste determination per 40 CFR Part 261.
- Drum and Saddle Tank Storage: All drums and saddle tanks containing materials other than fresh water or fluids that are gasses at atmospheric temperature and pressure must be stored on an impermeable pad with curbing. Chemicals in other containers such as sacks or buckets must be stored on an impermeable pad and curb type containment.
- Facility General Areas: Any facility area which shows evidence that leaks and spills are reaching the ground surface must be either paved and curbed or have some type of spill collection.
- Above Ground Tanks: All above ground tanks which contain fluids other than fresh water must be contained in an impermeable, bermed enclosure to contain a volume of one-third more than the total volume of the largest tank or of all interconnected tanks.

Table 2.4 (continued)

- Below Grade Tanks/Sumps: All below grade tanks, sumps, and pits must have secondary containment and leak detection.
- Housekeeping: Proposed methods for preventing contaminants from reaching the ground surface must be stated in the BMP. Records of inspections must be made and retained.
- Spill Reporting: All spills/releases will be reported and remediated pursuant to OCD Rule 116 and WQCC 1203.
- Surface Water Protection: Any water contaminants must be contained within the facility boundaries. A description of the methods used to achieve this goal must be included in the BMP.
- Catch stormwater and use it as make-up water in the process. For example, use contaminated stormwater for first stage washing of equipment, use stormwater as make-up water in drilling/completion operations, and use stormwater for process water.

The following BMPs have been used in New Mexico. They are from the website:

University of Colorado Law School, 6/4/2009. Intermountain Oil and Gas BMP Project; http://www.oilandgasbmps.org/index.php

- All roads will follow Gold Book standards (BLM and USFS 1989) to reduce soil erosion.
- Any roads used exclusively for construction purposes shall be adequately closed to all vehicular travel and rehabilitated after completion of construction.
- If produced water meets the New Mexico Water Quality Control Commission surface water standards, consider using it for irrigation of reclaimed areas until vegetation is established. Saline water treatment technologies show promise of economic feasibility.
- Construct road and pipeline crossings perpendicular to wetland/riparian areas, including ephemeral channels. Minimize the duration of construction and concentrate activity during dry conditions. Reshape disturbed channels to their approximate original configuration.
- Divert washes around well pads.
- Employ silt curtains, dikes, coffer dams, or other suitable erosion control measures. Replace lost riparian woody vegetation at a ratio of 2 acres for each acre lost, and 10 saplings for each mature tree lost.
- Install culverts of sufficient size (minimum 18 inches) will be placed where drainages cross access roads.
- Sidehill cuts of more than 3 feet vertical are not permitted. Areas requiring cuts greater than this will be terraced so none are greater than 3 feet.
- Maintain a vegetated buffer zone along watercourses, including ephemeral arroyos, sufficient to minimize headcutting and sediment delivery.
- Mulch disturbed areas.
- Properly align roads, on moderate grades with a side slope, and ensure adequate drainage.
- Properly construct mud and blow pits: Soils and Water- Mitigation Measures: Various techniques will be employed to reduce soil erosion. ... Depending upon the site-specific situation, the chief mitigation measures to be employed include the following: Mud and blow pits will be constructed so as not to leak, break, or allow discharge of liquids or produced solids.
- Recontour and revegetate unused disturbed ground around wellpads and above buried pipeline soon after completion of the well.

Table 2.4 (continued)

- Clearing, grading, and other disturbance of soil and vegetation is limited to the minimum area required for construction.
- Disturbed areas will be reseeded following specifications using designated seed mixtures within one year of final construction.
- Water quality in drilling areas will be protected by the use of closed-loop drilling systems (i.e. pitless drilling)
- Water quality in drilling areas must be protected by the use of water-based drilling fluids.

Table 2.5
Ohio Regulatory Survey

Note: Oil & Gas Drilling and Production is regulated by the Department of Natural Resources Division of Mineral Resources Management

- Ohio Revised Code §1509, Revised December 2006 http://codes.ohio.gov/orc/1509
- Ohio Administrative Code §1501, Revised December, 2006 http://codes.ohio.gov/oac/1501:9
- Best Management Practices for Pre-Drilling Water Sampling, April, 2005 http://www.dnr.state.oh.us/Portals/11/oil/pdf/BMP_PRE-DRILLING_WATER_SAMPLING.pdf
- Best Management Practices for Oil and Gas Well Site Construction, Revised April, 2005 http://www.dnr.state.oh.us/Portals/11/publications/pdf/BMP_OIL_GAS_WELL_SITE_CONST.pdf
- Personal Communication with Steve Opritza of OHDNR-DMRM 4/22/09
- Personal communication with Beth Wilson of OH DNR-DMRM, 5/5/09

1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

A. General Regulations:

1. (§1509.22 (C-3), Ohio Revised Code): Pits may be used for containing brine and other waste substances resulting from, obtained from, or produced in connection with drilling, fracturing, reworking, reconditioning, plugging back, or plugging operations, but the pits shall be constructed and maintained to prevent the escape of brine and other waste substances. A dike or pit may be used for spill prevention and control. A dike or pit so used shall be constructed and maintained to prevent the escape of brine, and the reservoir within such a dike or pit shall be kept reasonably free of brine and other waste substances.

2. (§1509.22 (C-4), Ohio Revised Code): Earthen impoundments constructed pursuant to the division's specifications may be used for the temporary storage of brine and other waste substances in association with a saltwater injection well, an enhanced recovery project, or a solution mining project

3. (§1509.22 (C-6), Ohio Revised Code): May not be used for ultimate disposal of brine.

4. (§1501:9-3-08 (A), Ohio Administrative Code): All pits used for the temporary storage of saltwater and oil field wastes shall be liquid tight and constructed and maintained so as to prevent escape of saltwater and oil field wastes. Such pits shall not be used in an area which is subject to flooding by streams, rivers, lakes or drainage ditches, unless so constructed that the pits would not normally be affected by flooding.

5. (§1501:9-3-08 (C), Ohio Administrative Code): Pits may be used for the temporary storage of frac-water and other liquid substances produced from the fracturing process, but upon termination of the fracturing process, pits not otherwise permitted by this rule shall be emptied, the contents disposed of in accordance with law and the pits filled in, unless this requirement is waived or extended as provided in section 1509.072 of the Revised Code.

B. Pit Removal Requirements

1. Must be removed 5 months after the commencement of drilling operations (Topical Summary of Ohio Oil & Gas Law {updated 5/16/08})

2. Within five months after the date upon which the surface drilling of a well is commenced, the owner or the owner's agent, in accordance with the restoration plan filed under division (A)(10) of section 1509.06 of the

Revised Code, shall fill all the pits for containing brine, other waste substances resulting, obtained, or produced in connection with exploration or drilling for, or production of, oil or gas, or oil that are not required by other state or federal law or regulation, and remove all concrete bases, drilling supplies, and drilling equipment. (§1509.07.2 (A) of Ohio Revised Code)

a. Within six months after a well that has produced oil or gas is plugged, or after the plugging of a dry hole, the owner or the owner's agent shall remove all production and storage structures, supplies, and equipment, and any oil, salt water, and debris, and fill any remaining excavations. Within that period the owner or the owner's agent shall grade or terrace and plant, seed, or sod the area disturbed where necessary to bind the soil and prevent substantial erosion and sedimentation. The chief, by order, may shorten the time periods provided for under division (A) or (B) of this section if failure to shorten the periods would be likely to result in damage to public health or the waters or natural resources of the state. The chief, upon written application by an owner or an owner's agent showing reasonable cause, may extend the period within which restoration shall be completed under divisions (A) and (B) of this section, but not to exceed a further six-month period, except under extraordinarily adverse weather conditions or when essential equipment, fuel, or labor is unavailable to the owner or the owner's agent. If the chief refuses to approve a request for waiver or extension, the chief shall do so by order. (§1509.07.2 of Ohio Revised Code)

C. Pit Reclamation Requirements

1. Within nine months after the date upon which the surface drilling of a well is commenced, the owner or the owner's agent shall grade or terrace and plant, seed, or sod the area disturbed that is not required in production of the well where necessary to bind the soil and prevent substantial erosion and sedimentation. If the chief of the division of mineral resources management finds that a pit used for containing brine, other waste substances, or oil is in violation of section 1509.22 of the Revised Code or rules adopted or orders issued under it, the chief may require the pit to be emptied and closed before expiration of the five-month restoration period. (§1509.07.2 (A) of Ohio Revised Code)

D. Freeboard Requirement

1. Enough to prevent the escape of brine; ultimately determined by the chief of the division (Ohio Revised Code §1509.22 (C-3))

2. The level of saltwater in excavated pits shall at no time be permitted to rise above the lowest point of the ground surface level. All pits shall have a continuous embankment surrounding them sufficiently above the level of the surface to prevent surface water from entering. (§1501:9-3-08 (A), Ohio Administrative Code)

E. Tank Usage

1. Where tanks are used to contain saltwater and oil field wastes, they shall be liquid tight. Burial of any tank is prohibited except by written permission from the chief and where the burial is witnessed by an oil and gas well inspector. Steel tanks in use and proposed for use by burial shall be cathodically protected, and the chief shall make additional requirements as are necessary to prevent leakage of saltwater. No tank composed of a material other than steel shall be used for burial except by written permission of the chief. An oil and gas well inspector may gauge any tank at any time to determine if leakage is occurring.

F. Disposal of Liquid Fraction

1. Except when acting in accordance with section 1509.226 [1509.22.6] of the Revised Code, no person shall place or cause to be placed brine in surface or ground water or in or on the land in such quantities or in such manner as actually causes or could reasonably be anticipated to cause either of the following:
   a. Water used for consumption by humans or domestic animals to exceed the standards of the Safe Drinking Water Act;
   b. Damage or injury to public health or safety or the environment. (§1509.07.2 of Ohio Revised Code)

2. The chief of the division of mineral resources management shall adopt rules and issue orders regarding storage and disposal of brine and other waste substances; however, the storage and disposal of brine and the chief's rules relating to storage and disposal are subject to all of the following standards:
   a. Brine from any well except an exempt Mississippian well shall be disposed of only by injection into an underground formation, including annular disposal if approved by rule of the chief, which injection shall be subject to division (D) of this section; by surface application in accordance with section 1509.226 [1509.22.6] of the Revised Code; in association with a method of enhanced recovery as provided in section 1509.21 of the Revised Code; or by other methods approved by the chief for testing or implementing a new technology or method of disposal. Brine from exempt Mississippian wells shall not be discharged directly into the waters of the state.
   b. (4) Earthen impoundments constructed pursuant to the division's specifications may be used for the temporary storage of brine and other waste substances in association with a saltwater injection well, an enhanced recovery project, or a solution mining project;
   c. (5) No pit, earthen impoundment, or dike shall be used for the temporary storage of brine except in accordance with divisions (C)(3) and (4) of this section;
   d. (6) No pit or dike shall be used for the ultimate disposal of brine.

   (§1509.22 (C) (3) of OH Revised Code)

3. Saltwater and oil field wastes shall be drained or removed and properly disposed of periodically, at intervals not to exceed one hundred eighty days. (§1501:9-3-08 (A), Ohio Administrative Code)

4. The plan for disposal of water and other waste substances resulting from, obtained, or produced in connection with exploration, drilling, or production of oil or gas. The plan for disposal of salt water shall include identification of any disposal well or disposal wells to be used. A statement that one of the named disposal wells on the application shall be used, is sufficient. Where the applicant finds that the disposal well to be used is different from that indicated on the permit, the applicant shall so notify the division immediately in writing. The plan for disposal may include such other methods as are approved by the chief. Such plan shall include the name of the person or company disposing of the salt water and the ultimate location of its disposal. Any change in the plan for disposal shall be timely submitted to the chief. . (§1501:9-1-02 (A.3), Ohio Administrative Code)

G. Disposal of Solid Fraction

1. Solid waste disposal (§1509.22(B) (2), Ohio Revised Code).
   a. Muds, cuttings and other waste substance shall not be disposed in violation of any rule.

H. Pit Protection

1. Pits, pumps and flares must be safely fenced if within one hundred fifty (150) feet of an existing inhabited structure and if in the opinion of the Chief, such fence is necessary to protect life and limb. (Ohio Administrative Code §1501:9-9-05 Producing Operations-C)

I. Reclamation Exception

1. The owner shall be released from responsibility to perform any or all restoration requirements of this section on any part or all of the area disturbed upon the filing of a request for a waiver with and obtaining the written approval of the chief, which request shall be signed by the surface owner to certify the approval of the surface owner of the release sought. The chief shall approve the request unless the chief finds upon inspection that the waiver would be likely to result in substantial damage to adjoining property, substantial contamination of surface or underground water, or substantial erosion or sedimentation. (§1509.07.2 of Ohio Revised Code)

2. Water Well Testing Requirements

A. General Regulation

Table 2.5 (continued)

1. The well owner shall sample all water wells within three hundred (300) feet of the proposed well location in urbanized areas prior to drilling under the guidelines provided in the divisions BMPs for pre-drilling water sampling manual, dated April 30, 2005 that can be located at http://www.dnr.state.oh.us/mineral/oil/index.html or by contacting the division of mineral resources management. The chief may require modification of this distance if determined necessary to protect water supplies or site conditions may warrant. (Ohio Administrative Code, §1501:9-1-02 (F))

2. Sample for the following parameters:
   a. Dissolved Ba & Fe (μg/l), Total Ca, Mg, K & Na (mg/l), Cl, SO_4, Alkalinity & TDS (mg/l), pH, and Conductivity at 25^{o} C (μmohs/cm). (Best Management Practices For Pre-Drilling Water Sampling, 4/28/05)

B. Water Replacement

1. An owner shall replace the water supply of the holder of an interest in real property who obtains all or part of the holder's supply of water for domestic, agricultural, industrial, or other legitimate use from an underground or surface source where the supply has been substantially disrupted by contamination, diminution, or interruption proximately resulting from the owner's oil or gas operation, or the owner may elect to compensate the holder of the interest in real property for the difference between the fair market value of the interest before the damage occurred to the water supply and the fair market value after the damage occurred if the cost of replacing the water supply exceeds this difference in fair market values. (§1509.22 (F) of Ohio Revised Code)

2. During the pendency of any order issued under this division, the owner shall obtain for the holder or shall reimburse the holder for the reasonable cost of obtaining a water supply from the time of the contamination, diminution, or interruption by the operation until the owner has complied with an order of the chief for compliance with this division or such an order has been revoked or otherwise becomes not effective. (§1509.22 (F) of Ohio Revised Code)

3. If the owner elects to pay the difference in fair market values, but the owner and the holder have not agreed on the difference within thirty days after the chief issues an order for compliance with this division, within ten days after the expiration of that thirty-day period, the owner and the chief each shall appoint an appraiser to determine the difference in fair market values, except that the holder of the interest in real property may elect to appoint and compensate the holder's own appraiser, in which case the chief shall not appoint an appraiser. The two appraisers appointed shall appoint a third appraiser, and within thirty days after the appointment of the third appraiser, the three appraisers shall hold a hearing to determine the difference in fair market values. Within ten days after the hearing, the appraisers shall make their determination by majority vote and issue their final determination of the difference in fair market values. The chief shall accept a determination of the difference in fair market values made by agreement of the owner and holder or by appraisers under this division and shall make and dissolve orders accordingly. This division does not affect in any way the right of any person to enforce or protect, under applicable law, the person's interest in water resources affected by an oil or gas operation. (§1509.22 (F) of Ohio Revised Code)

3. Fracturing Fluid Requirements and Fluid Use and Recycling

A. Surface Water Use Restrictions and Regulations

1. Any removal larger than 100,000 gallons per day from the Ohio R. or Lake Erie Basins requires a permit according to Ohio Revised Code §1501.32-1501.35

2. Amount of allowed removal may decrease at the discretion of the Chief of the Department of Natural Resources-Division of Water (§1501.32-1501.35 of Ohio Administrative Code)

B. Treatment, Recycling, or Reuse Requirements for Drilling and Fracing Fluids

1. No person shall place brine in surface or ground water, or on the land in such quantities or in such a manner that causes or could reasonably be anticipated to cause:

a. water used for consumption by humans or domestic animals to exceed the standards of the Safe Drinking Water Act.
b. damage or injury to public health or safety or the environment. (Section 1509.22(A), ORC).
(TOPICAL SUMMARY OF OHIO OIL AND GAS LAW (updated 5/16/08))
c. Disposal and Usage Options (Section 1509.22(C), Ohio Revised Code)
   i. Injection
      (i) permitted conventional Class II injection well
      (ii) permitted enhanced recovery injection well
      (iii) permitted annular disposal well
   ii. Surface application for dust or ice control in accordance with an approved resolution.
   iii. Any other method approved by the Chief for testing or implementing a new technology.
   (TOPICAL SUMMARY OF OHIO OIL AND GAS LAW (updated 5/16/08)
d. Injection allowances are determined ultimately by the chief of the division. No person, without first having obtained a permit from the chief, shall inject brine or other waste substances resulting from, obtained from, or produced in connection with oil or gas drilling, exploration, or production into an underground formation unless a rule of the chief expressly authorizes the injection without a permit. The permit shall be in addition to any permit required by section 1509.05 of the Revised Code, and the permit application shall be accompanied by a permit fee of one hundred dollars. The chief shall adopt rules in accordance with Chapter 119. of the Revised Code regarding the injection into wells of brine and other waste substances resulting from, obtained from, or produced in connection with oil or gas drilling, exploration, or production. The rules shall include provisions regarding applications for and issuance of the permits required by this division; entry to conduct inspections and to examine and copy records to ascertain compliance with this division and rules, orders, and terms and conditions of permits adopted or issued under it; the provision and maintenance of information through monitoring, recordkeeping, and reporting; and other provisions in furtherance of the goals of this section and the Safe Drinking Water Act. To implement the goals of the Safe Drinking Water Act, the chief shall not issue a permit for the injection of brine or other waste substances resulting from, obtained from, or produced in connection with oil or gas drilling, exploration, or production unless the chief concludes that the applicant has demonstrated that the injection will not result in the presence of any contaminant in ground water that supplies or can reasonably be expected to supply any public water system, such that the presence of the contaminant may result in the system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons. This division and rules, orders, and terms and conditions of permits adopted or issued under it shall be construed to be no more stringent than required for compliance with the Safe Drinking Water Act unless essential to ensure that underground sources of drinking water will not be endangered. May only inject 200 barrels per day per well. (§1509.22 (D) of Ohio Revised Code)
e. Brine shall not be applied:
   i. To a water-saturated surface;
   ii. Directly to vegetation near or adjacent to surfaces being treated;
   iii. Within twelve feet of structures crossing bodies of water or crossing drainage ditches;
   (§1509.22.6 B-1(a-c) of Ohio Revised Code)

2. (§1501:9-3-08 (C), Ohio Administrative Code): Pits may be used for the temporary storage of frac-water and other liquid substances produced from the fracturing process, but upon termination of the fracturing process, pits not otherwise permitted by this rule shall be emptied, the contents disposed of in accordance with law and the pits filled in, unless this requirement is waived or extended as provided in section 1509.072 of the Revised Code.

4. Hydraulic Fracturing Operation Requirements

A. Ohio does not regulate Hydraulic Fracturing (Personal Communication with Steve Opritza of OH DNR-DMRM 4/22/09)

B. (§1501:9-3-08 (C), Ohio Administrative Code): Pits may be used for the temporary storage of frac-water and other liquid substances produced from the fracturing process, but upon termination of the fracturing process, pits not otherwise permitted by this rule shall be emptied, the contents disposed of in accordance with law and the pits filled in, unless this requirement is waived or extended as provided in section 1509.072 of the Revised Code.

5. Requirements to Minimize Potential Noise and Lighting Impacts

A. Flaring

1. The owner of any well producing both oil and gas may burn such gas in flares when the gas is lawfully produced and there is no economic market at the well for the escaping gas. (Ohio Revised Code §1509.20. Waste of oil or gas to be prevented; flaring of gas.)

2. All gas vented to the atmosphere must be flared, with the exception of gas released by a properly functioning relief device and gas released by controlled venting for testing, blowing down and cleaning out wells. Flares must be a minimum of 100 feet from the well, a minimum of 100 feet from oil production tanks and all other surface equipment, and 100 feet from existing inhabited structures and in a position so that any escaping oil or condensate cannot drain onto public roads or towards existing inhabited structures or other areas which could cause a safety hazard.

3. There is no regulation for the mitigation of light pollution due to drilling operations. (Personal communication with Beth Wilson of OH DNR-DMRM, 5/5/09)

B. Noise Pollution

1. Drilling, service and maintenance shall be conducted in a manner to mitigate noise. (Personal communication with Beth Wilson of OH DNR-DMRM, 5/5/09)

6. Setbacks

A. General Regulation

1. Rules of the chief of the division of mineral resources management may specify practices to be followed in the drilling of wells and production of oil and gas for protection of public health or safety or to prevent damage to natural resources, including specification of the following:
   a. (1) Appropriate devices;
   b. (2) Minimum distances that wells and other excavations, structures, and equipment shall be located from water wells, streets, roads, highways, rivers, lakes, streams, ponds, other bodies of water, railroad tracks, public or private recreational areas, zoning districts, and buildings or other structures;
   c. (3) Other methods of operation;
   d. (4) Procedures, methods, and equipment and other requirements for equipment to prevent and contain discharges of oil from oil production facilities and oil drilling and workover facilities consistent with and equivalent in scope, content, and coverage to section 311(j)(1)(c) of the "Federal Water Pollution Control Act Amendments of 1972," 86 Stat. 886, 33 U.S.C.A. 1251, as amended, and regulations adopted under it.

   (Ohio Revised Code §1509.23 (A))

B. Adjacent Gas Well Heads

1. Requirement With Depth
   a. 0-1000 ft depth: Min. 1 acre/well, Min. 200ft between wells of same pool, Min 100ft from unit boundary
   b. 1000-2000 ft depth: Min 10 acres/well, Min. 460 ft. between wells of same pool, Min. 230 ft from unit boundary
   c. 2000-4000 ft depth: Min 20 acres/well, Min 600 ft. between wells of same pool, Min 300 ft from unit boundary
   d. 4000+ ft depth: Min 40 acres/well, Min 1000 ft between wells of same pool, Min. 500 ft from unit boundary

   (Ohio Administrative Code §1501:9-1-04)

Table 2.5 (continued)

2. Surface Requirement
   a. A minimum of 100 ft from any other Oil or Gas Wells (Ohio Administrative Code §1501:9-9-03)

C. Private Dwelling & Wells, and Outside Boundaries

1. Well head should be located at least 100 feet from any private dwellings (Ohio Administrative Code §1501:9-9-03)

2. Private Wells must be a minimum of 200 feet from Gas wells (Ohio Administrative Code-Related To Water Wells, Dept. of Health §3701-28-10 (G))

3. For new applications to drill wells in urbanized areas, the proposed wellhead location shall be no closer than seventy five (75) feet to any property not within the subject tract or drilling unit. (Ohio Administrative Code §1501:9-1-04 Spacing of wells. (C)(5))
   a. Exception
      i. Locating the wellhead closer than seventy five (75) feet to a property not within the subject tract or drilling unit may be approved by the chief if the owner and resident of the property in question, in writing, approves of the proposed wellhead location, or the chief waives the seventy five (75) foot requirement. (§1501:9-1-04 Spacing of wells. (C)(5))

D. Highways, Streets, Railroad Tracks

1. Well head should be located at least 50 feet from railroad tracks, the traveled portion of streets, highways and roads (Ohio Administrative Code §1501:9-9-03)

E. Coal Mines

1. Greater than three hundred feet of any opening of any mine used as a means of ingress, egress, or ventilation for persons employed in the mine, nor within one hundred feet of any building or inflammable structure connected with the mine and actually used as a part of the operating equipment of the mine (Ohio Revised Code §1509.08. Issuance of permit; procedure when well is in coal bearing township; restrictions near mines)

2. Exceptions to the Requirement
   a. If the chief of the DMRM determines that life or property will not be endangered by drilling and operating the well in that location.

F. Streams, Domestic Supply Springs & Water Bodies

1. There is no minimum distance requirement for Gas wells from streams & water bodies. (Personal Communication with Steve Opritza of OHDNR-DMRM 4/22/09)

2. Wells drilled, deepened, reopened, reworked, or plugged back for purposes other than the production of oil and gas will be considered as special situations, and each will be evaluated in accordance with the issues of conservation of natural resources and of safety. Decisions as to spacing of such wells will be determined after evaluation of the special circumstances. Rules may be promulgated for some specific types of these wells. (Ohio Administrative Code §1501:9-1-04 Spacing of wells)

3. May be determined by the chief of the Division of Mineral Resource Management (Ohio Revised Code §1509.23. Rules to protect health, safety, and natural resources; (A)(2))

4. All persons engaged in any phase of operation of any well or wells shall conduct such operation or operations in a manner which will not contaminate or pollute the surface of the land, or water on the surface or in the subsurface (§1501:9-1-07 (A) of Ohio Administrative Code)

Table 2.5 (continued)

7. Multiple Well Pad Reclamation Practices – None Found, yet.

8. NORM

9. Storm Water Runoff

A. In urbanized areas, to minimize off-site sedimentation, erosion and to control the surface flow of water, the well owner and or authorized representative must follow the best management practices (BMPs) for oil and gas well site construction manual, dated April 30, 2005 that can be located at http://www.dnr.state.oh.us/mineral/oil/index.html or by contacting the division of mineral resources management, as provided by the chief. BMPs and other design standards other than provided by the chief maybe used if a well owner or their authorized representative demonstrates that the alternative BMP or practices minimize erosion to the same degree as the BMPs provided by the chief. (§1501:9-1-07 (A) of Ohio Administrative Code)

B. Site Construction Erosion Controls (Ohio DNR Best Management Practices for Oil and Gas Well Site Construction)

1. Access Roads
   a. Design Guidelines:
      i. 1. Minimum roadbed width should be 14 feet for a single lane and 20 feet for a double lane.
      ii. 2. Side slopes for excavated cuts should, in no case, exceed 2:1.
      iii. 3. Earthen fill slopes should be no steeper than 2:1.
      iv. 4. Install side ditches on road sections where surface runoff endangers fill areas.
      v. 5. Install adequate culverts under the road and in natural drainage ways unless a bridge is needed for larger drainage areas.
      vi. 6. Place culverts across roadways to handle flows from the side ditch when permissible velocity is exceeded in the ditch. For spacing requirement, see Table # 1.
      vii. 7. Provide headwalls or drop inlets if erosion of the inlet is a problem.
      viii. 8. Headwalls can be constructed of rock riprap, logs or concrete.
      ix. 9. Grades should normally not exceed 15% except for short lengths but maximum grades of 20% may be used, if necessary, for special purposes.
      x. 10. Do *not* locate roads near water courses whenever possible.
      xi. 11. Areas having soils that are slide prone should be avoided. If these areas cannot be avoided the access road should be located in a manner that would minimize cuts and fills.
      xii. 12. Reseed, mulch, etc., roadbanks, roadbeds and all other disturbances promptly and in accordance with the recommended rates.
   b. Construction Guidelines: The area to be excavated or occupied by a fill should be cleared and grubbed of all trees, stumps, large roots, boulders and debris. All such material should be disposed of by burning, burial or removal from sites. With landowner approval, brush piles may be created to enhance wildlife habitat.

2. Water Bars for Access Roads
   a. A channel or open ditch should be constructed diagonally across roads to carry surface runoff to prevent accumulation of large volumes of water by diverting surface runoff from road surface at designed intervals. Erosion in the form of gullies may be prevented by construction of water bars. They are to be constructed using compacted soils
   b. Design guidelines:
      i. 1. Minimum height-8 inches.
      ii. 2. Minimum top width-2 feet (6 feet including downhill toe)
      iii. 3. Water bars should be at a 30 degree angle to the road at an outslope of 2-4%.
      iv. 4. Cross section should be parabolic (see figure 1.)
      v. 5. Provide a safe outlet to prevent erosion caused by water discharge. Material for an outlet may be rock, concrete, etc., of sufficient composition and quantity to prevent soil detachment.
   c. Construction Guidelines: Construct water bars to a specified line and grade. The soil should be well graded and ready for seeding.

Table 2.5 (continued)

i. 1. Location – Place water bars at the head of any slope (or edge of a wellsite) and then spaced appropriately down the slope.
ii. 2. Spacing – Water bars are only effective when spaced at recommended distances. For spacing recommendations see Table 1.

Table 1. Spacing of Water Bars (per U.S. Forest Service)

Road Grade (%)	Distance Between Bars (feet)
2	300
3	235
4	200
5	180
6	165
7	155
8	150
9	145
10	140

d. Maintenance: Where access roads will be used frequently when soil conditions are wet, the roadway will require frequent grading unless a crushed rock surface is installed. Water bars should be reshaped after each grading operation.

3. Broad Based Dips
   a. Broad based dips can be used where no intermittent or permanent streams cross the road. They are particularly effective when constructed on an access road that intersects small swales or drainage patterns. Because of the construction techniques this type of dip should not be used on roads exceeding 10% grade. Dips should be lined with crushed rock or gravel. They do no increase wear on vehicles or reduced hauling speed when properly installed. Use Table 2 to calculate proper spacing. Protect the discharge area from erosion. The outlet may require stone or a good grass sod.
   b. Operators should construct a dip or swale across a road surface with the dip sloped to the outslope for drainage to provide cross drainage on roads during and after well development to prevent excessive buildup of surface runoff.
   c. C. Design/Construction Guidelines
      i. 1. Maximum road grade on which dips can be constructed is 10%.
      ii. 2. Minimum width should be 20 feet.
      iii. 3. Construct a 3% reverse grade in an existing roadbed by cutting upgrade of the dip location.
      iv. 4. Spacing – See Table 2.

Table 2. Spacing of Broad Based Dips

Road Grade (%)	Distance Between Bars (feet)
2	300
3	235
4	200
5	180
6	165
7	155
8	150
9	145
10	140

4. Pipe Culverts for Access Roads
   a. Pipe culverts are usually installed on permanent roads at the time of construction. They are commonly used where vehicle traffic will be relatively heavy following drilling activity or where access roads cross significant drainage patterns. Pipe structures are the most expensive type of cross drain but are quite effective in controlling water. Because of the additional cost, it is important to properly install and maintain the culvert.

Table 2.5 (continued)

b. Materials 1. Steel 2. Concrete 3. Cast Iron 4. Aluminum 5. Plastic (heavy wall)
c. Design Guidelines:
   i. 1. For pipe culverts used to divert road side ditch water, use same spacing requirements as water bars. See Table 1.
   ii. 2. For culverts located below sizable watersheds (between 10-500 acres) see Table 3.
   iii. 3. Minimum suggested culvert size is a 15 inch diameter.
   iv. 4. Position culverts at approximately 30° downgrade. See Figure 3.
   v. 5. Culvert grade should be less than ½ inch per foot of pipe (4.0%)
   vi. 6. Use at least 12 inches of earth cover or ½ of the diameter of the pipe, whichever is greater, to cover the pipe. Culverts should extend to the lower edge of fill.
   vii. 7. Provide adequate materials to prevent erosion at pipe discharge.
   viii. 8. Pipes should have headwalls at their inlet when collecting water from road side ditches.
d. Construction Guidelines Install culverts to a specified line and grade. The ditch should be excavated to a depth and grade to insure adequate cover for the pipe. A minimum of one foot of cover or half the diameter of earth cover, whichever is greater, is considered adequate. If adequate cover cannot be achieved, install an arch pipe or two smaller pipes. A firm foundation is needed to support the pipe. The soil should be well compacted along the pipe and free of rock, roots and clumps. A back hoe is recommended for pipe culvert installation.

TABLE 3: Pipe Sizes for Culverts Across Road

Drainage Area (Acres)	Pipe Diameter (Inches)	Pipe Capacity (cu. ft. / sec.)
10	15	5
20	18	9
30	21	12
50	24	18
80	27	24
100	30	29
230	36	50
400	42	72

5. Access Road Entrance
   a. Erosion often occurs where an access road joins an established roadway. Steep slopes and concentrated run off may cause severe gully erosion and result in sedimentation on the roadway and/or in the ditch. Most local governments have restrictions and standards for entrances. Generally, requirements include culvert pipes and a stone roadbed for a specific distance. Producers should check with officials for local regulations. Properly designed access road entrances should permit a clear view of the highway. They should be constructed so water or stone will not run on to the road pavement. Whenever possible, avoid making excessive cuts when constructing the access road entrance. Road matting works effectively in supporting and preventing stone from incorporating into the soil. Road matting may greatly extend the lifetime of the stone roadbed.

6. Diversion Ditch
   a. Diversion ditches should be constructed while the site is being prepared. Diversions, when constructed at the top of the cut slope and at the base of the site, will effectively reduce erosion and drainage problems.
   b. Design Guidelines:
      i. 1. For drainage area less than 2 acres
         (i) a. Minimum depth of 18 inches
         (ii) b. Minimum top width – 8 feet
         (iii) c. Maximum ditch grade 2%
         (iv) d. Minimum ditch grade 0.5%
      ii. 2. For drainage area greater than 2 acres and when area being protected is of high value:
         (i) a. Capacity of the ditch should handle a 10 year frequency storm for a 24 hour duration.

7. Surface Drains
   a. Surface drain may be needed where drilling activity intercepts or blocks natural drainage patterns, or where excavation may trap runoff. Surface drains are used in flat areas with low grades, usually less than 2% and

small drainage areas. When properly designed, a drained site may dramatically improve working conditions and reduce maintenance costs and restoration problems.

b. Design Guidelines:
   i. 1. Ditch side slopes should not be steeper than 3:1 when excavated in soil.
   ii. 2. Base capacity of ditch on handling 0.1 cubic feet per second (CFS) per acres of drainage. Minimum depth should be 1.5 foot with 3:1 side slopes and should not exceed 2.0% grade.
   iii. 3. Cross section of the ditch should be V-shaped for ditches 1% or less. Ditches over 1% should be flat bottomed or parabolically shaped.
   iv. 4. Ditches should be seeded, lined or paved with stone, riprap, etc., to prevent erosion.

c. Construction Guidelines:
   i. 1. Cut the ditch to a designated line and grade. The spoil should be spread and leveled so that the surface water can flow into the ditch.
   ii. 2. Excavated surfaces should be reasonably uniform and smooth. Areas to be excavated should be cleared of trees and brush and should be disposed of by burning, burying or removal.

Table 4 Permissible Velocities

Soil Texture	Max. Velocity (feet/second)
Sand & sandy loam (noncolloidal)	2.5
Silt Loam (also high lime clay)	3.0
Sandy clay loam	3.5
Clay loam	4.0
Stiff clay, fine gravel, graded loam to gravel	5.0
Graded silt to cobbles (colloidal)	5.5
Shale. hardpan & coarse gravel	6.0

8. Filter Strips

a. Filter strips are the last line of defense to stop sediment from reaching streams. They help maintain water quality by trapping erosion sediments between the disturbed area and the stream system. By leaving essentially undisturbed buffer strips of vegetation between the streams, access roads, well sites and other disturbed areas, the existing vegetation will help trap sediment and prevent it from reaching the stream. Filter strips, however, are no substitute for protecting the disturbed area and cannot be expected to protect water quality alone.

b. Design Guidelines:
   i. 1. Roads and other disturbed areas located above a stream course need a filter strip. The width of the filter strip depends on the slope of the land between the disturbed area and the water course. See Table 5 for spacing requirements.
   ii. 2. In areas where a filter strip may have to be constructed, follow critical area treatment procedures. See Table 8.

c. Construction Guidelines:
   i. The filter strip areas should not be disturbed. No equipment operation that will expose the soil should be allowed in this area.

Table 5 Recommended Widths for Vegetation Strips Between Earthmoving Activities and Streams

Slope Between Disturbed Surface & Streams (%)	Width of filter strip: In Forested Area (ft)	In Municipal Watersheds & Critical Areas (ft)
0	25	50
10	45	90
20	65	130
30	85	170
40	105	210
50	125	250
70+	165+	330+

9. Sediment Barriers

a. Sediment barriers should be used in areas where excessive soil loss or sediment loads to a water course could cause serious problems. They should be used when activity above the barrier leaves bare soil even for a short period.
   i. Types of Barriers:
      (i) 1. Hay or straw bales.

Table 2.5 (continued)

(ii) 2. Silt fences.

b. Design Guidelines:

i. 1. Place straw bale dikes and silt fence on contour.

ii. 2. Spacing is governed by slope. Use the following guideline.

% Slope	Distance between barriers (ft)
2-8	110-92
8-12	92-75
12-18	80-60
18-24	60-52

c. Construction Guidelines:

i. 1. Place hay or straw bales in a row along the contour with adjacent bales securely tied with either wire or nylon string. Anchor each bale with two metal or wooden stakes at least 2” x 2” and driven into the ground a minimum of 1½ feet apart. Bales should be placed in the ground at least four inches.

ii. 2. Place silt fences on the contour. Space fence posts not more than 10 feet apart. If woven wire fencing is used, fasten it securely on the upstream side of the fence posts.

iii. 3. Road Matting/Filter Fabric High traffic areas often require placement of gravel or stone to prevent erosion and to keep the area accessible during wet periods. After a short period of time the gravel seems to disappear as it’s pressed into the subsoil, along with your investment. Road matting or filter fabric is designed to provide support for the layer of stone while allowing water to drain into the soil. It is particularly effective in wet soils or heavy use areas but requires careful installation to work properly. The following steps are installation guidelines to be used with manufacturer’s instructions:

(i) a. Scalp topsoil from area keeping it evenly distributed so as not to affect road drainage. Salvaged topsoil could be used on the well site itself.

(ii) b. Place fabric on firm, level subsoil. Lap seams at least 1 foot and anchor all edges. Anchoring may consist of manufactured staples placed on 3 foot centers, burying the edges of the fabric 6 inches or hand spreading 4 inches of No. 1 stone along all edges at least 1 foot wide.

(iii) c. Place 6 inches of angular No. 304 stone over the fabric while avoiding misplacing the fabric. Placement may be by tailgating, or shoveling. The maximum drop must be 3 feet or less. Extend stone 1 foot beyond the edge of the fabric.

(iv) d. Compact stone with a farm tractor or similar vehicle. Top off road with 3 inches of screenings or other road surface material.

10. Vegetative Practices

a. Vegetative practices should be designed and implemented in order to minimize soil erosion and sedimentation of surface water. It is highly recommended that native species be used whenever possible. Disturbed areas should be seeded and mulched as soon as possible after they are no longer necessary in the drilling or producing of a well.

Table 2.6
Pennsylvania Regulatory Survey

Agency: Pennsylvania Department of Environmental Protection (PADEP)

Regulations, Acts, and Laws:

- The Oil and Gas (O&G) Act (P.L. 1140, No. 223) (58 P.S. Section 601.101 et seq.)
- Coal and Gas Resource Coordination Act (P.L. 1069, No. 214) (58 P.S. Section 501.1 et seq.)
- Oil and Gas Conservation Law (P.L. 825, No. 359) (58 P.S. Section 401.1 et seq.)
- The Clean Streams (CS) Law (P.L. 1987, No.394) (35 P.S. Section 691.1 et seq.)
- Solid Waste management Act (SWA) (P.L. 380, No. 97) (35 P.S. Section 6018.101 et seq.)
- The Administrative Code (P.L. 177, No. 175) (71 P.S. Section 510-1 et seq.)
- 25 Pa. Code Chapters 78, 79, 91, 92, 93, 95, 96, 102, 105, 106, 260, 261, 287, 288, 289, 291, 293, 299

1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

Reference: Pennsylvania Department of Environmental Protection (PADEP), 5/2009. Pennsylvania Administrative Code, Title 25 Environmental Protection, Chapter 78 Oil and Gas; www.pacode.com/secure/data/025/chapter78/chap78toc.html

A. Regulations

1. PA Code §78.54 - General Requirements: Operator shall control and dispose of fluids, residual wastes and drill cuttings in a manner that prevents pollution of the waters.

2. PA Code §78.55 - Control and Disposal Plan: Prior to waste generation, the operator shall prepare and implement a plan (§91.34) for the control and disposal of fluids, residual waste and drill cuttings from any activity associated with oil and gas wells. The plan will be consistent with the O&G Act the CS Law, the SWM Act, and the PA Code, will be revised prior to changing the practices in the field, and will be provided to the PADEP upon request.

3. PA Code §78.56 - Pits and Tanks for Temporary Containment: §78.56(a): Operator must install and maintain a pit, tank, or series of pits and tanks to contain pollutional substances and wastes from drilling, altering, completing, recompleting, serving, and plugging a well, unless permits have been obtained under §78.60(b) (discharge requirements) allowing discharge to waters or §78.61(b) (disposal of drill cuttings) allowing land application of cuttings.

4. PA Code §78.57 - Control, Storage and Disposal of Production Fluids: §78.57(a): Operator must collect fluids produced during operation, service, and plugging of a well in a tank, pit, or series of pits or tanks or other device approved by the PADEP for disposal or reuse, unless permits have been obtained under §78.60(a) (discharge requirements) allowing discharge to waters. §78.57(b): Operator may not use a pit for the control, handling or storage of fluids produced during operation, service, or plugging of a well, except as provided in §78.56 (temporary containment) or unless a pit is authorized under The CS Law (35 P.S. §§691.1-691.1001) or

Table 2.6 (continued)

5. PADEP approves the operation of the pit as an impoundment under §78.56(c). §78.57(c): Operator may apply for approval to operate the pit as an impoundment under The CS Law.

6. PA Code §78.58 - Existing Pits Used for the Control, Storage and Disposal of Production Fluids: For pits in existence on July 29, 1989, operator may request approval for alternate methods to satisfy the depth of the pit bottom, the pit inside slopes, and the liner and subbase specifications by demonstrating that the pit is impermeable and that the method used to demonstrate this will provide protection at least as good as that provided by §78.57.

7. PA Code §78.61 - Disposal of Drill Cuttings: §78.61(a): drill cuttings from above the casing seat (if installed properly; see §78.83) may be disposed of in a pit at the well site if the listed pit specifications are met. §78.61(b): drill cuttings from above the casing seat (if installed properly; see §78.83) may be disposed of by land application at the well site if the listed land application specifications are satisfied. §78.61(c): drill cuttings from below the casing seat may be disposed of in a pit that meets the requirements of §78.62 or by land application in accordance with §78.63. §78.61(d): may use alternative practices to dispose of uncontaminated drill cuttings with PADEP approval.

8. PA Code §78.62 - Disposal of Residual Waste (including contaminated drill cuttings) – pits: §78.62(a-b): Solid residual waste may be disposed of in a pit at the well site if the listed requirements and pit specifications are met. §78.62(c): With approval from the PADEP, solidifiers or other alternate practices may be used for the disposal of residual waste if the practice provides equivalent or superior protection than the requirements of §78.62(a).

9. PA Code §78.63 Disposal of Residual Waste (including contaminated drill cuttings) - land application: §78.63(a-b): Solid residual waste may be disposed of by land application at the well site if the listed requirements and practices are followed. §78.63(c): With approval from the PADEP, alternate practices may be used for the disposal of residual waste if the practice provides equivalent or superior protection than the requirements of §78.63(a).

B. Tank Requirement

Required for the control, handling, or storage of fluids produced during operation, service, or plugging of a well (PA Code §78.57(b))

Except as provided in §78.56 (temporary containment) or unless a pit is authorized under The Clean Streams Law (35 P.S. §§691.1-691.1001) or approved by PADEP as an impoundment under §78.56(c)

C. Pit Construction Specifications

1. Volume: If used as an impoundment, < 250,000 gallons (1 pit or 2 or more connected) or < 500,000 gallons total (pits on one tract or related tracts of land) (PA Code §78.57(c), §78.58)

2. Location / Setbacks: impoundment for production fluids: >100' from stream, wetland, or water body (unless waived by PADEP) (PA Code §78.57(c), §78.58)

   Impoundment for cuttings from above the casing seat: >100' from stream, wetland, or water body (unless waived by PADEP); >200 feet from a water supply (PA Code §78.61(a))

   Impoundment for solid residual waste from below the casing seat (including contaminated drill cuttings): >200' horizontally from existing building (or waiver from owner); >100' from stream, wetland, or water body; >200' from water supply PA Code §78.62(a-b))

Table 2.6 (continued)

3. Freeboard: 2 feet

4. Separation: no info. found

5. Depth of Bottom: 20” above seasonal high GW table

6. Subbase / Subgrade: smooth, uniform, rock- & debris-free, capable of bearing the weight of pit contents without settling that will affect the liner integrity, lined with 6 inches of sand, soil, or smooth gravel if necessary to prevent failure

7. Slopes: pit used as an impoundment for control, storage and disposal of production fluids (with approval), inside pit slope not steeper than a ratio of 2 horizontal to 1 vertical (§78.57(c))

8. Surface Water Diversion: required if pit used as an impoundment for control, storage and disposal of production fluids (with approval)

9. Protection: pit must be reasonably protected from unauthorized acts of third parties if used as an impoundment for control, storage and disposal of production fluids (with approval)

D. Pit / Impoundment Liner Specifications

1. Coefficient of Permeability: </= $1x10^{-7}$ cm/s

2. Thickness / Strength: thick / strong enough to prevent failure, at least 30 mils

3. Composition: synthetic, flexible, nonreactive to pit contents; satisfy EPA Method 9090 or other data approved by PADEP; alternate liner or natural materials if approved by PADEP

4. Seams: sealed in accordance with the manufacturer's directions

E. Land Application Specifications (PA Code §78.63)

1. Location: land application area >200' horizontally from existing building (or waiver from owner); >100' of stream, wetland, or water body; >200' from water supply; >1,000' upgradient from uncased wells or springs used as a water supply

2. Depth to Seasonal High GW Table: ground level at land application area is at least 20" above the seasonal high GW table

3. Subgrade: Soils located within and immediately adjacent to the land application area are sandy loam, loam, sandy clay loam, silty clay loam, or silt loam (USDA classes) and have a min. depth to bedrock of 20".

4. Slopes: Application area ground slope </= 25%

F. Pit and Waste Removal and Disposal

1. Time Limit for Waste Disposal & Pit Removal / Filling: 9 months after completion of drilling, altering, completing, recompleting, serving, or plugging a well, unless pit was approved to be used for production fluid control, storage, or disposal (§78.57, §78.58) or permitted under CS Law, 35 P.S. §§691.1-691.1001. With approval, the pit can serve as an impoundment until the well is abandoned or PADEP approval is revoked (PA Code §78.62).

2. Waste Toxicity Limits:

Table 2.6 (continued)

a. Disposal in Pit: Contaminant concentration in the waste leachate </=50 % of the max conc. in §261.24 Table I (Max. Conc. of Contaminants for the Toxicity Characteristic) & </= 50 times the primary max cont. conc. under §109.202 (state MCLs, MRDLs & treatment technique req. & for health-related cont., conc. in the leachate </=50 times the safe drinking water level est. by the PADEP (PA Code §78.62)

b. Land Application: Contaminant concentration in the waste leachate </= the max conc. in §261.24 Table I (Max. Conc. of Contaminants for the Toxicity Characteristic) (PA Code §78.63)

3. Liquid Fraction Disposal

   a. owner and operator may not cause or allow a discharge to PA waters unless it complies with this subchapter and Ch 91-93 (Water Resources: General Provisions, National Pollutant Discharge Elimination System (NPDES) Permitting, Monitoring & Compliance, Water Quality Standards), 95 (Wastewater Treatment Requirements) & 102 (Erosion & Sediment (E&S) Control); the CS Law (35 P.S. §§691.1 - 691.1001 and the O&G Act (PA Code §78.60(a))

   b. must be removed prior to solid waste encapsulation or land application

4. Solid Fraction Disposal and Encapsulation or Application

   a. Uncontaminated Drill Cuttings: generated from a well at the site; drillings are not contaminated (w/brine, drilling mud, stimulation fluids, oil, production fluids or drilling fluids other than tophole water, fresh water or gases) (§78.61(a-b))

      i. Pit: Backfill to ground surface and grade to promote runoff and to prevent ponding with stability compatible with adjacent land.

      ii. Land Application: Drill cuttings are: not spread when ground is saturated, frozen, or snow covered; spread and incorporated into the soil; not applied in quantities that would cause surface or ground water pollution or affect the intended use of the vegetation.

   b. Contaminated Drill Cuttings or Residual Waste: must be generated by the drilling or production of an oil or gas well at the site that is permitted or registered under the Oil & Gas Act, bonded, and in compliance with the PA Code.

      i. Pit (§78.62(a-c)):

         1. Contaminant concentration in the waste leachate </=50 % of the maximum contaminant concentration in §261.24 Table I (Maximum Concentration of Contaminants for the Toxicity Characteristic) & </= 50 times the primary max cont. conc. under §109.202 (state MCLs, MRDLs & treatment technique req. & for health-related cont., conc. in the leachate </=50 times the safe drinking water level est. by the PADEP.

         2. Completely cover the waste by folding over the liner or by adding liner. The waste should be shaped so that water does not infiltrate the liner and is not confined above the liner. The liner cannot be punctured or perforated.

         3. Backfill to ground surface (at least 18") and grade to promote runoff and to prevent ponding with stability compatible with adjacent land.

4. With approval from the PADEP, solidifiers or other alternate practices may be used for the disposal of residual waste if the practice provides equivalent or superior protection than the requirements of §78.62(a).

ii. Land Application (§78.63(a-c)):

1. Contaminant concentration in the waste leachate </= the max conc. in §261.24 Table I (Max. Conc. of Contaminants for the Toxicity Characteristic).

2. Must notify PADEP at least 3 working days prior to start of land application.

3. Waste is: not spread when ground is saturated, frozen, or snow covered; incorporated into the soil to a depth of 6"; not applied in quantities that would cause surface or ground water pollution or affect the intended use of the vegetation. Loading and application rate must be consistent with PADEP guidelines for proposed operation, and the waste to soil ratio may not exceed 1:1. If failure to comply, must remediate appl. area until compliance is demonstrated.

4. With approval from the PADEP, alternate practices may be used for the disposal of residual waste if the practice provides equivalent or superior protection than the requirements of §78.63(a).

G. Reclamation of Disposal Area: Revegetate to comply with §78.53 (E&S Control), creating a diverse, effective, permanent cover capable of regeneration and plant succession. Stabilize against accelerated erosion if vegetation interferes with intended use.

2. Water Well Testing Requirements

References:

- PADEP, 4/30/09; Pennsylvania Statutes and Consolidated Statutes Annotated, Title 58 – Oil and Gas, Chapter 11 – Oil and Gas Act; http://www.dep.state.pa.us/dep/DEPUTATE/MINRES/OILGAS/Act223CH2.htm#Section_208
- www.pacode.com/secure/data/025/chapter78/chap78toc.html
- Pennsylvania State University, College of Agricultural Sciences Cooperative Extension, School of Forest Resources, 2009. Water Facts #28, Gas Well Drilling and Your Private Water Supply; http://resources.cas.psu.edu/waterresources/pdfs/gasdrilling.pdf

A. Regulations: PA Code §78.51 – Protection of Water Supplies: §78.51 (a): A well operator who affects a public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternate source of water adequate in quantity and quality for the purposes served by the supply. §78.51 (b-c): If the water supply is affected, the landowner, water purveyor or affected person should notify the PADEP. The PADEP will decide if there is pollution or diminution and if it was caused by the drilling, alteration or operation activities. §78.51 (d): The operator shall demonstrate that the quality of the restored or replaced water supply to be used for human consumption is at least equal to the quality of the water supply before it was affected by the operator. If the quality of the water supply before it was affected by the operator cannot be established, the operator shall demonstrate that the concentrations of substances in the restored or replaced water supply do not exceed the primary and secondary maximum contaminant levels established under §109.202 (State MCLs, MRDLs and treatment technique requirements).

B. Pre-Drilling Testing Requirements: None

Table 2.6 (continued)

C. Pre-Drilling Testing Recommendations

1. Quality: Monitor the quality of any water supply within 1000 feet of a proposed drilling operation using an independent, state-certified, water testing laboratory. A gas well operator is presumed to be responsible for the degradation of any ground water supply within 1000 feet of a gas well if the pollution occurs within 6 months of the well completion.

a. Suggested Parameters

i. Salts: Na, Cl

ii. Metals: Fe, Mn, Ba, As

b. Other Possible Parameters, depending on the circumstances

i. Coliform bacteria

ii. Methane

iii. Organics

2. Quantity: Gas well operators are not presumed responsible for water quantity impacts.

D. Post-Drilling Testing Requirements: None. PADEP conducts an inspection if any complaints are received

E. Post-Drilling Testing Recommendations: Only monitor for quality for defense against complaints.

3. Fracturing Fluid Requirements and Fluid Use and Recycling

Reference: PADEP, 4/11/09; Permitting Strategy for High TDS Wastewater Discharges; www.depweb.state.pa.us/watersupply/lib/watersupply/high_tds_wastewater/high_tds_wastewater_strategy_041109.pdf

A. Currently using NPDES permitting procedure with final effluent limitations are the more stringent of the federal Effluent Guidelines and Standards and the Water Quality-based Effluent Limitations.

B. Proposed permitting strategy: To amend PA Code 25 Chapters 93 (to include new criteria) and 95 (new effluent standards) by 1/1/2011.

C. Proposed regulatory change (Ch 95): add effluent standards for O&G wastewaters of TDS 500 mg/L, sulfates and chlorides 250 mg/L each, total barium and total strontium 10 mg/l each; POTWs that accept O&G waters need EPA-approved pretreatment for TDS through local limits and the above standards.

D. Interim plan: PADEP will only issue permits for NEW industrial high-TDS sources unless the applicant will install adequate treatment by 1/2011. Allocation of assimilative capacity will end 1/1/2011. After 1/1/2011, new regulations will be in effect. Existing industrial sources of high-TDS wastewater can continue to operate under existing permit limits until they propose to expand or increase their existing daily discharge load of any pollutant of concern. If that happens, they will be treated as a NEW source.

4. Hydraulic Fracturing Operation Requirements

References:

Table 2.6 (continued)

- PADEP, 4/22/09; Oil and Gas Management Facility Specific Forms @ http://www.dep.state.pa.us/dep/deputate/minres/oilgas/o_gforms.htm
- PADEP Bureau of Oil and Gas Management (BOGM), October 30, 2001; Oil & Gas Operators Manual, 550-0300-001.
- PADEP BOGM, October 31, 1998; Oil and Gas Well Drilling Permits and Related Approvals, 550-2100-003.

A. Operator's General Information Form, 5500-FM-OG0099; 10/2005

1. Only necessary for applicants that have not previously conducted business with the PADEP Oil & Gas Program
2. Agency: PADEP BOGM

B. Erosion, Sediment and Stormwater Control Module, 5500-PM-OG0001a

1. Necessary if >/= 5 acres will be disturbed (including access roads)
2. Agency: PADEP

C. Erosion, Sediment and Stormwater Control Plan for Oil and Gas Operations, 5500-FM-OG0111

Agency: PADEP

D. Proofs of Notifications to surface landowner; all landowners or water purveyors whose water supplies are within 1000 feet of proposed well location; gas storage operators within 2000 feet, all coal owners and lessees of all underlying workable coal seams, operators of underlying coal mines; and coal operators with a deep mine within 1000 feet

1. Must be completed prior to submitting the Permit Application for Drilling or Altering a Well (5500-PM-OG0001)
2. Agency: PADEP

E. Permit Application for Drilling or Altering a Well, 5500-PM-OG0001; 3/2009

1. Must include proofs of notification for those listed in item D
2. Agencies: PADEP Oil and Gas Management Program (OGMP)

F. Well Location Plat, 5500-PM-OG0002; 9/2008

G. Susquehanna River Basin Commission (SRBC) or Delaware River Basin Commission (DRBC) Notification if source is located in the SRB or DRB, respectively

Agencies: SRBC / DRBC

H. Notification to municipalities and counties in which the water sources for fracture stimulation for each Marcellus Shale natural gas well project are located

1. Must be completed prior to submitting the Water Management Plan (5500-PM-OG0087)
2. Agency: PADEP

Table 2.6 (continued)

I. Water Management Plan for Marcellus Shale Gas Well Development, 5500-PM-OG0087

1. Must include proofs of notification for SRBC, DRBC, municipalities, and counties when necessary

2. This form is a sample format only

3. Agency: PADEP BOGM & Bureau of Watershed Management (BWM)

J. Worksheet for Permitting of Marcellus Shale Pits and Dams, 5500-PM-OG0086

Use to determine what permits or approvals are necessary for proposed impoundment pits and dams for the development of a Marcellus Shale Gas Well.

K. Application for a Dam Permit for a Centralized Impoundment Dam for a Marcellus Shale Gas Well, 5500-PM-OG0084

Agency: PADEP BOGM & Bureau of Waterways Engineering (BWE)

L. Design, Construction and Maintenance Standards for Dam Embankments Associated with Impoundments for Oil and Gas Wells, 5500-PM-OG0085

Agency: PADEP BWE & BOGM

M. Approval from Pennsylvania Historical & Museum Commission (PHMC)

1. Must implement PA History Code if disturbed area will be >/= 10 acres. [37 PA CSA, Section 101 et. Seq. & Article 1, Section 27 PA Constitution]

2. Agencies: PADEP & PHMC

N. Determination of whether or not proposed well site is a Coal or Noncoal Area Well

1. Must include information to support a "noncoal" declaration, unless in a county where there are no workable coals

2. Agency: PADEP

O. Any Requests for Waivers, Exceptions, or Variances necessary to drill in the proposed location

1. for example, distances or well spacing based on coal operations, distance from surface water, wetlands, buildings, water supplies, public resources

2. Agency: PADEP

P. Review for Impact of Proposed Well Location on Public Resources

1. If there is a conflict between the proposed well location and a public resource (OGA, 58 P.S. §601.205(c), DEP will notify applicant and resource's responsible agency so negotiations can take place.

2. Agency: PADEP

Q. Request for DEP to compare proposed location to Pennsylvania Natural Diversity Inventory (PNDI)

1. This should be submitted prior to the application completion to save time and expense.

Table 2.6 (continued)

2. Agency: PADEP

R. Proposed Alternate Method or Material for Casing, Plugging, Venting, or Equipping a Well, 5500-PM-OG0024; 9/1997

1. Necessary for approval of alternate methods or materials.

2. Approval can be given in the field by an oil and gas inspector; the inspector must document the approval in writing within 10 days

3. Agency: PADEP

5. Noise and Light Impact Minimization and Mitigation – None found, yet.

6. Setbacks

References:

- PADEP BOGM, October 30, 2001; Oil & Gas Operators Manual, 550-0300-001

- PADEP; Springs, Stream, Body of Water, or Wetland Request for Waiver for Distance Requirements, 5500-PM-OG0057

- PADEP; Distance Restrictions from Existing Building or Water Supply Request for Variance, 5500-PM-OG0058

- PADEP; Permit Application for Drilling or Altering a Well, 5500-PM-OG0001 FIND ACTUAL REGULATION

A. Regulations, Acts, and Laws

1. Oil and Gas Act (OGA), Sec. 601.205 – Well Location Restrictions

   Exceptions:

   - the owner has given consent

   - Where the setback would deprive the owner of oil & gas rights, the operator may be granted a variance.

2. Oil and Gas Conservation Law (OGCL)

3. Coal and Gas Resource Coordination Act (CRCA) - well distance requirements for non-conservation gas wells penetrating a workable coal seam

B. Setback Reference Point: "well site" – includes all of the disturbed area around the well location and the access roads (OGA)

C. Specific Setbacks

1. all existing wells: 1000' (CRCA)

2. private water wells: 200' measured horizontally (OGA)

3. domestic supply springs: 200' horizontally from any water supply (PADEP pub. 5500-PM-OG0001)

Table 2.6 (continued)

4. surface water body or wetland: 100’ measured horizontally (OGA)

5. private dwellings: 200’, measured horizontally, from existing buildings

6. outermost lease or unit boundary: 330’ (OGCL)

7. adjacent gas wells: no information found

8. active (operating or projected) coal mine: 1000’ outside the mine boundary (CRCA)

9. gas storage reservoir: 2000’ outside of the reservoir boundary (CRCA)

10. landfills: outside of the permitted (landfill) area (CRCA)

D. Setback Revisions based on drilling duration, fracturing fluid volume, and number of wells at one pad: No information found.

7. Multi-Well Reclamation

References: www.pacode.com/secure/data/025/chapter78/chap78toc.html

A. Regulations

1. PA Code §78.53 – Erosion and Sediment Control: During and after soil disturbing activities, including restoring the access road and site, the operator shall design, implement and maintain BMPs in accordance with Chapter 102 and an erosion and sediment control plan prepared under that chapter.

2. PA Code §78.57 - Control, Storage and Disposal of Production Fluids:

   a. §78.57(a):

      i. Operator must collect fluids produced during operation, service, and plugging of a well in a tank, pit, or series of pits or tanks or other device approved by the PADEP for disposal or reuse

      ii. unless permits have been obtained under §78.60(a) (discharge requirements) allowing discharge to waters.

   b. §78.57(b):

      i. Operator may not use a pit for the control, handling or storage of fluids produced during operation, service, or plugging of a well

      ii. except as provided in §78.56 (temporary containment) or unless a pit is authorized under The CS Law (35 P.S. §§691.1-691.1001)

      iii. or unless PADEP approves the operation of the pit as an impoundment under §78.56(c).

   c. §78.57(c): Operator may apply for approval to operate the pit as an impoundment under The CS Law.

3. PA Code §78.58 - Existing Pits Used for the Control, Storage and Disposal of Production Fluids: For pits in existence on July 29, 1989, operator may request approval for alternate methods to satisfy the depth of the pit bottom, the pit inside slopes, and the liner and sub-base specifications by demonstrating that the pit is impermeable and that the method used to demonstrate this will provide protection at least as good as that is provided by §78.57.

Table 2.6 (continued)

4. PA Code §78.61 - Disposal of Drill Cuttings:
5. PA Code §102 -

B. Typical Reclamation for Multi-well Pads

8. Storm Water Best Management Practices for Sites with Greater Than 1 Acre of Total Disturbance

References: PADEP, 2006. Pennsylvania Stormwater Best Management Practices, 363-0300-002.

A. Non-Structural BMPs

1. Protect Sensitive and Special Value Resources
   a. protect sensitive and special value features
   b. protect/conserve/enhance riparian areas
   c. protect/utilize natural flow pathways in overall stromwater planning and design

2. Cluster and Concentrate
   a. cluster uses at each site; build on the smallest area possible
   b. concentrate uses area-wide

3. Minimize Disturbance and Minimize Maintenance
   a. minimize total disturbed area - grading
   b. minimize soil compaction in disturbed areas
   c. re-vegetate and re-forest disturbed areas using native species

4. Reduce Impervious Cover
   a. reduce road imperviousness
   b. reduce parking imperviousness

5. Disconnect/Distribute/Decentralize
   a. rooftop disconnection
   b. disconnection from storm sewers

6. Source Control
   a. street/road sweeping

B. Structural BMPs

1. Volume/Peak Rate Reduction by Infiltration
   a. pervious pavement w/infiltration bed
   b. infiltration basin/trench
   c. subsurface infiltration bed
   d. vegetation
   e. dry well/seepage pit
   f. infiltration berm & retentive grading

2. Volume/Peak Rate Reduction
   a. vegetation
   b. runoff capture and reuse

3. Runoff Quality/Peak Rate
   a. constructed wetlands
   b. wet pond/retention basin
   c. dry extended retention basin

Table 2.6 (continued)

   d. water quality filters and hydrodynamic devices

4. Restoration
   a. riparian buffer restoration
   b. landscape restoration
   c. soil amendment and restoration
   d. floodplain restoration

5. Other and Related Structural Measures
   a. level spreader
   b. special detention areas

Table 2.7
Texas Regulatory Survey

Agencies:

- Railroad Commission of Texas (RRC) (jurisdiction over all issues, unless noted)
- Texas Commission on Environmental Quality (TCEQ) (jurisdiction only where noted)
- Texas General Land Office (GLO), Coastal Coordination Council (CCC), Texas Coastal Management Program (CMP) (jurisdiction only where noted)
- Groundwater Conservation District (enforcement divisions created by the TCEQ) (jurisdiction only where noted)
- Texas Department of Licensing and Regulation (jurisdiction only where noted)
- Texas Water Development Board (jurisdiction only where noted)
- Texas Department of Health

1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

References:

Texas Administrative Code, Title 16 Economic Regulation, Part 1 Railroad Commission of Texas, Chapter 3 Oil and Gas Division;
http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3

Regulations:

1. TAC, Title 16 Economic Regulation, Part 1 RRC, Chapter 3 OGD, Rule §3.8(d) Pollution Control
2. TAC, Rule §3.8(e) Pollution Prevention
3. TAC, Rule §3.8(i) Coordination between the RRC and the TCEQ
4. TAC, Rule §3.8(j) Consistency with the CMP, (A) Disposal of Oil and Gas Wastes in Pits
5. TAC, Rule §3.8(j) Consistency with the CMP, (B) Discharge of Oil and Gas Wastes to Surface Waters: In the coastal zone:
   - no discharge of oil and gas waste to surface waters may cause a violation of the Texas Surface Water Quality Standards adopted by the TCEQ (Title 30, TAC, Chapter 307)
   - in determining whether any permit to discharge oil and gas waste that is comprised, in whole or in part, of produced water is consistent with the CMP, the RRC shall consider the effects of salinity from the discharge
   - to the greatest extent practicable, the outfall for an oil and gas waste discharge shall not be located where it will adversely affect any critical area

6. TAC, Rule §3.9 Disposal Wells

Table 2.7 (continued)

7. TAC, Rule §3.22 Protection of Birds

8. TAC, Rule §3.46 Fluid Injection into Productive Reservoirs

9. TAC, Rule §3.98 Standards for Management of hazardous Oil and Gas Wells

10. General Requirements: Operator shall control and dispose of fluids, residual wastes and drill cuttings in a manner that prevents pollution of the waters.

A. Tank Requirement

There is no mention of a tank requirement until completion fluids have been displaced. (Rule §3.8)

B. Pit Construction Specifications:

1. General:

a. Permits for the storage or disposal of gas wastes, brines, or mineralized water in pits will only be issued by the RRC if disposal or storage will not result in the waste of resources or the pollution of surface or subsurface water (TAC Rule §3.8(d)(6)). Permits for storage or disposal:

i. will state conditions reasonably necessary to prevent waste and pollution.

ii. will state the conditions under which a pit may be operated, dewatered, backfilled, and compacted.

iii. may contain requirements relating to pit construction materials, dike design, liner material, liner thickness, liner installation procedures, liner inspection and replacement schedules, overflow warning devices, leak detection devices, and fences.

iv. will contain requirements relating to liner material, liner thickness, liner installation procedures, and liner inspection and replacement schedules for lined brine mining pits or any lined pits for oil field brines, geothermal resource waters, or other mineralized waters.

b. With the RRC Application for Permit to Maintain and Use a Pit (Form H-11; 5/1984), the applicant must submit:

i. a drawing of two perpendicular sectional views

ii. the data on liner material, thickness, and installation procedures if the pit will be lined

iii. soil and subsoil identification and description

iv. an engineering design drawing of the pit and leak detection system if applicable OR procedures for periodic maintenance and liner integrity check

v. include justification for pit size for saltwater storage

c. Pits used for disposal in the coastal zone must be designed to prevent releases of pollutants that adversely affect coastal waters or critical areas (TAC Rule §3.8(j)(1)).

2. Specifics:

a. Volume and Area:

Basic sediment pit: </= 50 barrels; </= 250 square feet

b. Location / Setbacks:

Pits used for disposal of oil and gas wastes may not be located in any Coastal Natural Resource Areas (CNRAs)

c. Freeboard: no information found

d. Separation: no information found

e. Depth of Bottom: no information found

f. Subbase / Subgrade: no information found

g. Slopes: no information found

h. Surface Water Diversion: no information found

i. Protection: no information found

j. Cover: a screen, net or cover (for the protection of birds) must be used on pits and open-top tanks that are used as skimming or collecting pits or that have a diameter >/= 8 feet & have a continuous or frequent surface accumulation of oil (TAC Rule §3.22).

Exceptions: temporary, portable storage tanks used to hold fluids during drilling operations, workovers, or well tests

C. Pit / Impoundment Liner Specifications – no specs

1. RRC rules require an operator to take precautions to prevent pollution of surface and subsurface water, but do not include specific requirements for plastic liners in drilling pits and fracture stimulation water pits. Many operators use liners in areas where the soil is permeable. Local governments may require the use of lined pits. (RRC, Barnett Shale Information)

2. With the RRC Application for Permit to Maintain and Use a Pit (Form H-11; 5/1984), the applicant must submit:

   - the data on liner material, thickness, and installation procedures if the pit will be lined
   - an engineering design drawing of the pit and leak detection system if applicable OR procedures for periodic maintenance and liner integrity check

D. Land Application Specifications – See subsection E, below.

E. Pit and Waste Removal and Disposal

1. Prohibited Disposal Methods (TAC Rule §3.8(d)(1)): must have a permit to dispose of any oil and gas wastes by any method.

   Exceptions:

   - Disposal methods authorized for certain wastes. See subsection 3, below.

Table 2.7 (continued)

- Texas offshore and adjacent estuarine zones (TAC Rule §3.8(e)(2)(A)): Disposal of liquid waste allowed, limited to saltwater and other materials which have been treated, when necessary, to remove constituents which may be harmful to aquatic life or injurious to life or property.
- Deck areas on drilling and producing platforms, barges, workover units, and associated equipment shall be curbed or drained. The containment will be treated and disposed of without causing hazard or pollution. (TAC Rule §3.8(e)(2)(C&G)).
- Solid combustible waste (TAC Rule §3.8(e)(2)(D)): Burn and dispose of ashes into Texas offshore and adjacent estuarine zones.
- Edible garbage (TAC Rule §3.8(e)(2)(D)): Dispose of into Texas offshore and adjacent estuarine zones if consumable by aquatic life without causing harm.
- Oil-free drilling cuttings and fluids from mud systems may be disposed of into Texas offshore and adjacent estuarine zones at or near the surface. (TAC Rule §3.8(e)(2)(E))
- Gas hazardous waste must be transported to and disposed of at a designated hazardous waste facility. (TAC Rule §3.98)
- Disposal methods required to be permitted pursuant to §3.9 (disposal wells). (TAC Rule §3.9)
- Disposal methods required to be permitted pursuant to §3.46 (fluid injection into productive reservoirs). (TAC Rule §3.46)

2. Time Limit for Waste Disposal & Pit Removal / Filling: See subsection E4, below.

3. Waste Toxicity and Disposal Method Limits:

   a. Any disposal method, EXCEPT disposal into surface water: Without a permit – may dispose of

      i. Fresh water condensate from natural gas that has been collected at gas pipeline drips or compressor stations

      ii. Inert and essentially insoluble gas wastes including (not limited to) concrete, glass, wood, wire

   b. Land Application: Without a permit, with surface owner's written permission – may dispose of the following gas wastes on the same lease where generated (TAC Rule §3.8(d)(3)(C)):

      ii. Everything in subsection a

      iii. Water base drilling fluids, chloride conc. </= 3,000 mg/l

      iv. Drill cuttings, sands, and silts obtained using water base drilling fluids, chloride conc. </= 3,000 mg/l

      v. Wash water used for cleaning equipment at the well site

   c. Disposal in Pit (Burial): Without a permit -- may dispose of the following gas wastes on the same lease where generated (TAC Rule §3.8(d)(3)(A-E)):

      i. Everything in subsections a and b

Table 2.7 (continued)

   ii. Water base drilling fluids, chloride conc., >/=3,000 mg/l, which have been dewatered

   iii. Drill cuttings, sands, and silts obtained using water base drilling fluids, no chloride conc. limit

4. Specific Pit Types: Allowed Wastes, Backfill Requirements; Schedules (TAC Rule §3.8(d)(4)):

   a. Completion / workover pit

      i. Allowed wastes: dewatered completion/workover wastes, after dewatering, including: spent completion and workover fluids and materials cleaned out of the wellbore of a well being completed or worked over.

      ii. dewatered within 30 days; backfilled and compacted within 120 days of cessation of use

   b. Reserve or mud circulation pit

      i. Allowed wastes: drilling fluids, drill cuttings, wash water, drill stem test fluids, and blowout preventer test fluids

      ii. with fluids with chloride conc. </= 6,100 mg/l: dewatered , backfilled, and compacted within 1 year of the cessation of drilling operations

      iii. with fluids with chloride conc. > 6,100 mg/l: dewatered within 30 days and backfilled and compacted within 1 year of the cessation of drilling operations

      iv. Sectioned reserve pit: treat each section as a separate pit for dewatering schedule

   c. Basic sediment pits

      i. Allowed wastes: only basic sediment from a production vessel or the bottom of an oil storage tank; no oil or free salt water

      ii. Dewatered, backfilled, and compacted within 120 days of the final cessation of the use of the pits

   d. Flare pits

      i. Allowed wastes: only hydrocarbons designed to go to the flare during upset conditions at the well, tank battery, or gas plant where the pit is located; hydrocarbon storage limited to 48 hours at a time

      ii. Dewatered, backfilled, and compacted within 120 days of the final cessation of the use of the pits

   e. Fresh makeup water pits and fresh water mining pits

      i. Allowed wastes: only water used to make up drilling fluid and water used for solution mining of brine

      ii. Dewatered, backfilled, and compacted within 120 days of the final cessation of the use of the pits

   f. Water condensate pits

      i. Allowed wastes: fresh water condensed from natural gas and collected at pipeline drips or compressor stations

Table 2.7 (continued)

ii. Dewatered, backfilled, and compacted within 120 days of the final cessation of the use of the pits

5. Liquid Fraction Disposal: See subsections 1, 3 & 4 above.

6. Solid Fraction Disposal and Encapsulation or Application: See subsections 1, 3 & 4 above.

7. Pits requiring permits (TAC Rule §3.8(d)(2)):

   a. Saltwater pits: sw disposal, emergency sw storage, collecting, skimming, brine, brine mining

   b. other pits: drilling fluid storage (other than mud and circulation pits), drilling fluid disposal (other than reserve pits or slush pits), washout, and gas plant evaporation / retention

F. Reclamation of Disposal Area: No information found.

2. Water Well Testing Requirements – No information found.

3. Fracturing Fluid Requirements and Fluid Use and Recycling

References:

- Texas Legislature Online, 5/25/09; Texas Statutes: Natural Resources Code, Title 3: Oil and Gas; http://tlo2.tlc.state.tx.us/statutes/nr.toc.htm

- Texas Legislature Online, 5/25/09; Texas Statutes: Natural Resources Code, Title 2: Water Administration; http://tlo2.tlc.state.tx.us/statutes/wa.toc.htm

- Railroad Commission of Texas, 6/3/09; Water Use in the Barrett Shale; http://www.rrc.state.tx.us/barrettshale/wateruse_barrettshale.php

- Railroad Commission of Texas, 6/3/09; Barrett Shale: Water Use in Association with Oil and Gas Activities Regulated by the Railroad Commission of Texas; http://www.rrc.state.tx.us/barrettshale/wateruse.php

- Texas Commission on Environmental Quality, 6/3/09; Water Rights, Am I Regulated?; http://www.tceq.state.tx.us/permitting/water_supply/water_rights/wr_amiregulated.html

- Texas Legislature Online, 6/1/09; Texas Statutes: Natural Resources Code, Title 2: Water Administration; Texas Water Code, Chapter 11; http://tlo2.tlc.state.tx.us/statutes/docs/WA/content/htm/wa.002.00.000011.00.htm

- Texas Groundwater Protection Committee, 6/3/09; http://www.tgpc.state.tx.us/GWManagement.htm

A. Regulations:

1. Texas Water Code, Chapter 11: Water Rights

2. Texas Water Code, Chapter 28: Water Wells and Drilled or Mined Shafts, §28.011: Underground Water - Except as otherwise provided by this code, the commission may make and enforce rules and regulations for protecting and preserving the quality of underground water.

3. Texas Water Code, Chapter 36: Groundwater Conservation Districts, §36.117: Exemptions; Exception; Limitations - (b) A district may not require any permit issued by the district for: (2) the drilling of a water well

used solely to supply water for a rig that is actively engaged in drilling or exploration operations for an oil or gas well permitted by the Railroad Commission of Texas provided that the person holding the permit is responsible for drilling and operating the water well and the well is located on the same lease or field associated with the drilling rig; or (3) the drilling of a water well authorized under a permit issued by the Railroad Commission of Texas under Chapter 134, Natural Resources Code, or for production from such a well to the extent the withdrawals are required for mining activities regardless of any subsequent use of the water.

4. Texas Occupations Code, Chapter 1901: Water Well Drillers, §§28.151, 251, 253-256: explain driller licensing, well log, completion, plugging requirements, notice of injurious water, and rule enforcement by GCD
5. TAC, Title 16 Economic Regulation, Part 1 RRC, Chapter 3 OGD, Rule §3.5 Application to Drill Deepen, Reenter, or Plug Back
6. TAC, Title 16 Economic Regulation, Part 1 RRC, Chapter 3 OGD, Rule §3.13 Casing, Cementing, Drilling, and Completion Requirements
7. TAC, Title 16 Economic Regulation, Part 1 RRC, Chapter 3 OGD, Rule §3.14 Plugging

B. Fracture Fluid Reporting Requirements – No information found.

C. Fracture Fluid Use – Source Regulation and Restrictions

Definitions and Inconsistencies:

Injection supply well – water well used to supply water for activities related to the exploration or production of hydrocarbons or minerals (TWC §36.117(l))

Rig supply well – water well used solely to supply water for a rig that is actively engaged in drilling or exploration operations for an oil or gas well permitted by the RRC (TWC §36.117)

RRC interprets “a rig that is actively engaged in drilling or exploration operations for an oil or gas well permitted by the RRC” to mean a drilling or workover rig and interprets “exploration operations” to include well completion and workover, including hydraulic fracturing operations. Apparently, the Texas Department of Licensing and Regulation (TDLR) does not.

1. Surface Water (TCEQ)

   a. A Water Right, authorization from the TCEQ, is necessary to divert surface water (>10 acre-feet (3,258,510 gallons) of surface water or a term of water use that is longer than 1 year) for use in drilling and gas production activities. (TWC, Chapter 11)

   b. A Temporary Water Right is a permit authorizing </= 10 acre-feet of surface water for one year or less.

2. Ground Water

   a. **Saline or Brackish Water**: Rig Supply Wells and Injection Supply Wells that penetrate the base of usable quality water (RRC, Texas Department of Licensing and Regulation (TDLR))

      i. Rig Supply Well (TWC, Chapter 28 & Texas Occupations Code (TOC), §1901.251)

      - Agency: TDLR

Table 2.7 (continued)

- Driller must notify TDLR and the landowner or person having the well drilled on encountering water injurious to vegetation, land, or other water and on determining that the well must be plugged, repaired, or properly completed in order to avoid injury or pollution.
- Driller must ensure well is plugged, repaired, or properly completed under standards and procedures adopted by TDLR.

ii. Injection Supply Well

- Agency: RRC
- A permit is required to drill an injection water supply well that penetrates the base of usable quality water. (16 TAC §3.5)
- The supply well must be completed in accordance with Statewide Rule 13. (16 TAC §3.13)
- The supply well must be plugged in accordance with Rule 14. (16 TAC §3.14)

b. **Fresh water**: Rig Supply Wells and Injection Supply Wells that do not penetrate the base of usable quality water ((TDLR), Texas Water Development Board (TWDB), Ground Water Conservation District (GCD))

i. Both Rig Supply Wells & Injection Supply Wells (fresh)

- must be drilled by a licensed Water Well Driller (TDLR – TOC, §1901.151)
- Logs and other required information must be submitted to the TDLR and the Texas Water Development Board (TWDB) of the TCEQ (TOC, §1901.251).
- Completion and plugging must comply with TDLR regulations (TOC, §1901.253).
- An abandoned or deteriorated well must be plugged or capped within 180 days. (TOC, §§1901.254 - 256). The Ground Water Conservation Districts (GCDs) can enforce the plugging regulations for abandoned or deteriorated water wells.
- Must submit a plugging report for a supply well to GCD and TDLR.

ii. Rig Supply Wells (TWC §36.117)

- Exempt from GCD permitting requirements
- Must be registered, equipped and maintained in accordance with GCD rules
- Drilling log must be submitted to the GCD

iii. Injection Supply Wells

- An injection water source well is not regulated as a “water well” after drilling (TOC, Chapter 1901), so it is not regulated under §91.101 of the Natural Resources Code. (TWC §36.117(b)(2))
- Under GCD jurisdiction; GCD permit required if drilled after 9/1/1985; GCD cannot deny the permit if the application meets GCD rules. (TWC §36.117)

Table 2.7 (continued)

- Must be completed and plugged in accordance with TDLR rules; well plugging must be submitted to the GCD and TDLR. (TOC, §§1901.253 – 255).

D. Recycling – Pilot Projects only (http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php)

1. Fountain Quail Water Management (Jacksboro) uses a recycling process that reuses approximately 80% of the returned fracture fluid used in the Barnett Shale play. This recycling process involves on-site distilling units that apply heat to separate brine from water used to fracture gas formations. When water injected to fracture formations returns to the surface, it becomes unusable due to its high salt content. Under this project, instead of hauling unusable return fracture fluid to a disposal well, the fracture flow-back fluid is stored in tanks on location and piped into treatment equipment. Natural gas produced on location is used to fire the distilling units that in turn boil the returned fracture fluid and produce fresh distilled water. The distilled water can then be used to fracture treat another Barnett Shale well. On October 30, 2006, the Commissioners authorized Fountain Quail on a permanent basis to treat fracture flow-back fluid. As of April 26, 2008, Fountain Quail has processed over 5.7 million barrels of returned fracture fluid to recover over 4.5 million barrels of reusable water.

2. DTE Gas Resources, Inc. was granted authority on April 18, 2006 to conduct a pilot project to store, handle, treat and re-use fracture flow-back water at two Barnett Shale gas well drill sites in Tarrant and/or Jack Counties. The fracture flow-back water must be treated with on-site separation and filtration. On November 13, 2007, DTE Gas Resources has reported that they ceased the pilot project to store, handle, treat and re-use flow-back water from Barnett Shale gas wells. DTE reported that the project was found non-viable economically.

3. Devon Energy Production Company, LP was granted authorization effective January 15, 2007, to perform a pilot project to store, handle, treat and re-use fracture flow-back fluid from five to ten Barnett Shale gas well drill sites. The fracture flow-back water must be treated with on-site separation and filtration. On October 22, 2007, Devon reported that the EMS Water Treatment System pilot project has ended. Devon has indicated that fracture flow-back fluid was brought into the system for treatment; however, no recycled water was used to fracture. On July 15, 2008, RRC approved Devon for another pilot project to treat and re-use fracture flow-back fluids and produced water from Barnett Shale.

4. Burlington Resources and Stroud Energy were authorized in 2003 and 2005, respectively, to re-use flowback water from fracturing operations in the Barnett shale without a permit for use in future fracturing operations or drilling new wells.

5. Hydraulic Fracturing Operation Requirements

References:

- Railroad Commission of Texas, 4/25/09; Oil & Gas Filing Checklist From Prospect to Production: Oil & Gas Forms and Procedures; http://www.rrc.state.tx.us/forms/forms/og/checklist.php.

- Texas Administrative Code, Title 16 Economic Regulation, Part 1 Railroad Commission of Texas, Chapter 3 Oil and Gas Division; http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3

A. Identification

1. Organization Report, P-5, and financial assurance (Rule §3.1)

   Agencies: RRC, Oil and Gas Division

Table 2.7 (continued)

2. RCRA Subtitle C Site Identification Form , EPA 8700-12.

   Agency: RRC, Oil and Gas Division and USEPA

B. Permitting

   Agency: RRC, Oil and Gas Division (unless noted)

1. Application for a Permit to Appropriate Public Water (AKA A Water Right) (TCEQ)

   a. Necessary if planning to use more than 10 acre-feet of water from any surface water source or if water use will occur over more than one year.

   b. Permit is good for 3 years.

   c. Include fee

   d. Include a plat

2. Application for Permit to Drill Recomplete or Re-Enter, W-1; 10/2004 (Standard Size and Shape Tract) (Rules §3.5, §3.37, §3.78)

   a. fee

   b. Well Location Plat, 1” = 1000’

3. Non-Standard Size or Shape Tract, W-1A; 07/2004 (Rules §3.37, §3.38, §3.78)

   a. Form is in addition to W-1 for first and only well on a substandard or non-standard size or shape tract or lease under applicable spacing and density rules; also necessary when using surplus acreage as a substandard pooled unit.

   b. fee for rule exception

4. Supplemental Horizontal Well Information, W-1H (Rules §3.37, §3.38, §3.78)

5. Supplemental Directional Well Information, W-1D (Rules §3.37, §3.38, §3.78)

6. Certificate of Pooling Authority, P-12 (Rules §3.37, §3.40)

   a. necessary when pooling multiple tracts together to meet minimum drilling unit acreage requirements

   b. submit with plat of each pooled unit

7. Sour Gas, H-9 (Rule §3.36): File in triplicate 30 days before drilling if in potential sour gas zone.

8. Application for Permit to Maintain and Use a Pit, Form H-11; 5/1984

   Agency: RRC; Austin, TX and district office

   a. Plat with pit location

   b. County highway map (1” = 4 miles) showing pit location

Table 2.7 (continued)

c. Drawing of two perpendicular sectional views

d. Lined pit – attach data on liner material, thickness, and installation procedures

e. Soil and subsoil identification and description

f. Engineering design drawing of the pit and leak detection system if applicable OR procedures for periodic maintenance and liner integrity check

g. Salt water storage – include justification for pit size

h. Notice of Pit Permit Application

   i. Given to:

   - Surface owners of tracts where the pit will be located and where the disposal will occur
   - Government official (ex. City clerk) of the incorporated entity within which the pit will be located or disposal will occur
   - (if disposal is to be by discharge into a watercourse other than the Gulf of Mexico) Surface owners of waterfront tracts between discharge point and ½ mile downstream, except for those waterfront tracts within the corporate limits of an incorporated city, town, or village
   - (if disposal is to be by discharge into a watercourse other than the Gulf of Mexico and one or more waterfront tracts is within the corporate limits of an incorporated city, town, or village) City clerk or other appropriate official

   ii. Consisting of:

   - A copy of the application
   - Statement that any protest of the application should be filed with the RRC within 15 days of the date the application is filed with the RRC.

   iii. Delivered or mailed on or before the date the application is mailed or delivered to the RRC (Austin)

   iv. Additional notices may be required by the RRC

   v. Publication of the Notice

   - The RRC may require notice publication if the applicant is unable to reach someone who must receive notification. The form of the notice will be decided by the RRC
   - The notice must be published once weekly, for two consecutive weeks, in a newspaper of general circulation in the county where the pit will be located or the disposal will occur.
   - Proof of publication must be filed with the RRC (Austin).

C. Drilling

Agencies: RRC, Oil and Gas Division and TCEQ

1. Request information concerning water protection requirements from the TCEQ. (Rule §3.13)

2. Drilling Fluid Pits – must be constructed, maintained and monitored in compliance with Rule §3.8.

3. Verify compliance with Rule §3.36 if in sour gas zones.

4. Inclination determinations every 500 – 1000’, starting at 500’ and a directional survey when necessary, W-12. (Rule §3.11)

D. Cementing Casings: Surface and Intermediate / Production (Rule §3.13)

Agency: RRC, Oil and Gas Division

1. Notify RRC 8 hours before running and cementing casing. Notify RRC of problems / corrective measures.

2. File W-15.

E. Completion

Agency: RRC, Oil and Gas Division

1. Install wellhead before perforation and testing. (Rule §3.13)

2. Use tanks once completion fluids have been displaced. (Rule §3.8)

3. Certificate of Compliance, P-4; to designate gatherers (Rule §3.58)

4. Request for Clearance of Storage Tanks for Authorization of Removal of Fluids, P-8; if tanks have been filled during testing. (Rule §3.58)

F. Testing

Agency: RRC, Oil and Gas Division

1. Notify RRC when ready to test. (Rules §3.16, §3.28, §3.31)

2. Gas Well Back Pressure Test, Completion or Recompletion Report, and Log, G-1;04/1983 (Rules §3.16, §3.28, §3.31). File with the RRC within earlier of 30 days of completion or 15 days of the absolute open-flow potential test.

3. Gas Well Classification Report, G-5; 01/1986; and Back Pressure Curve (Rules§3.16, §3.28, §3.31, §3.53). Submit to RRC if 4 or 1point potential test is run.

4. Statement of Productivity of Acreage Assigned to Proration Units, P-15; 05/1971 (Rule §3.31).

5. Electric Log Status Report, L-1; 01/2002 (Rule §3.16). File with completion report.

6. Notify RRC 24 hours before 72-hour deliverability test.

7. Gas Well Status Report, G-10; 09/2000 (Rules §3.28, §3.53, §3.55). Submit after testing if well is connected to a sales line.

G. Production – Report monthly (PR) and annually (G-10) to RRC (Rules §3.27, §3.54 & §3.28, §3.53, §3.55)

H. Clean-Up (Rule §3.8)

1. Reserve or Mud Pits with Chloride concentration of :

   a. </= 6,100 mg/L: Dewater and backfill within one year of completing drilling.

   b. > 6,100 mg/L: Dewater within 30 days, and backfill within one year of completing drilling.

2. Completion Pits: Dewater within 30 days, and backfill within 120 days of well completion.

I. Water Supply for Drilling Activities and Production: See main section **3(Fracturing Fluid Requirements and Fluid Use and Recycling**), above.

6. Noise and Light Impact Minimization and Mitigation

The RRC has no statutory authority over noise or nuisance related issues. These are governed by local ordinances.

Reference: Railroad Commission of Texas, 5/22/1009. Barnett Shale Information.
http://www.rrc.state.tx.us/barnettshale/index/php

7. Setbacks

References:

- Texas Administrative Code, Title 16 Economic Regulation, Part 1 Railroad Commission of Texas, Chapter 3 Oil and Gas Division;
  http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3

- Railroad Commission of Texas, 5/22/1009. Barnett Shale Information.
  http://www.rrc.state.tx.us/barnettshale/index/php

A. Regulations, Acts, and Laws

1. TAC, Title 16 Economic Regulation, Part 1 RRC, Chapter 3 OGD, Rule §3.37 Statewide Spacing Rule

   Exceptions:

   - RRC may grant exceptions to increase or decrease the minimum setbacks in order to protect life, to prevent waste, or to prevent the confiscation of property. An application and fee are required; in some instances, a 20-day waiting period is required after exception orders are issued.

   - No subdivision of property made after the adoption of the original spacing rule will be considered in applying the spacing rule.

   - A well bottomed off the lease, deviated after 4/1/1949, drilled in violation of a specific condition or limit placed in the Rule 37 permit, or is in violation of an RRC order, will not be permitted and is not replaceable. (An operator is not precluded from applying for approval of the bottom location of a deviated well as a reasonable location under the current rules, provided that the vertical projection of the permitted surface location is within the productive limits of the reservoir.)

Table 2.7 (continued)

3. TAC, Title 16 Economic Regulation, Part 1 RRC, Chapter 3 OGD, Rule §3.38 Well Densities

   Exceptions:

   - The spacing rules listed with their required acreage (subsection, 14 below) are not exclusive. Appropriate acreage assignments for any spacing rule can be made by the RRC.
   - RRC may grant exceptions to the density provision. An application and fee are required.

4. TAC, Title 16 Economic Regulation, Part 1 RRC, Chapter 3 OGD, Rule §3. 76 Commission Approval of Plats for Mineral Development

5. TAC, Title 16 Economic Regulation, Part 1 RRC, Chapter 3 OGD, Rule §3. 86 Horizontal Drainhole Wells

B. Setback Reference Point:

1. Vertical Wells (V) – Reference point is not clearly stated, but the regulations imply that the reference point is the surface location of the well

2. Horizontal Drainhole Wells (H) – All points along the horizontal drainhole (the portion of the wellbore between the penetration point – the point where the drainhole penetrates the top of the correlative interval - and the terminus

C. Specific Setbacks (V: TAC Rule §3.37(a)(1); H: TAC Rule §3.86) (unless noted)

Exception: If field rules exist, those distances override the distances listed.

1. private water wells: No information found.

2. domestic supply springs: No information found.

3. surface water body or wetland: No information found.

4. private dwellings: (RRC, Barnett Shale Information)

   a. RRC – unregulated; however, for a well within the city limits, the city may enact ordinances

   b. TAC Rule §3.76 – In counties with a population > 400,000 or a population > 140,000 adjacent to a county with a population > 400,000, a property developer may obtain RRC approval of a subdivision plan that limits drilling activity to designated sites of at least 2 acres for every 80 acres in the subdivision

   c. Many mineral leases include clauses that define the minimum setback from an existing structure.

5. lease, property, or subdivision line: 467’

6. adjacent wells completed in or being drilled to the same horizon on the same tract or farm (V) (or “in the same field on the same lease, pooled unit, or unitized tract” (H)):

   a. V: 1,200’ (minimum distance for 1 well/40 acres)

   b. H: 1,200’ (horizontal displacement), or other between-well spacing requirement under applicable field rules, from any point along a horizontal drainhole (HD) to any point along any other HD in another well, or to any other well completed or drilling in the same field on the same lease, pooled unit, or unitized tract.

7. Setback Revisions based on drilling duration, fracturing fluid volume, and number of wells at one pad: No information found.

8. Multi-Well Reclamation

References: Railroad Commission of Texas, 5/22/1009. Barnett Shale Information.

A. Regulations: None found.

B. Typical Reclamation for Multi-well Pads:

"There are no standard location shapes or sizes; each rig has its own individual "footprint." Texas law allows an operator the right to use as much of the surface as necessary to explore, drill and produce the minerals from a property. Leases or ordinances may limit the amount of surface that an operator may use and dictate restoration of the site." (RRC, Barnett Shale Information)

9. NORM Regulations

A. The disposal of produced water by injection into a well permitted under §3.9 of this title (relating to Disposal Wells) or §3.46 of this title (relating to Fluid Injection into Productive Reservoirs); discharge to surface waters and in accordance with a discharge permit issued under §3.8 of this title (relating to Water Protection); and disposal of equipment that has been decontaminated in accordance with a license issued by the TDH and that meets the exemption criteria of 25 TAC §289.259(d) (relating to Licensing of Naturally Occurring Radioactive Material (NORM)) are exempt from the regulations of TAC Title 16:1 Chapter 4.F §4.602

B. Except as provided in subsection (b) of this section, within two years of the effective date of this rule, each person who owns or operates equipment used for production or disposal including each person who owns or operates equipment associated with a commercial facility, as defined in §3.78 (relating to Fees and Financial Security Requirements), shall identify NORM-contaminated equipment with the letters "NORM" by securely attaching a clearly visible waterproof tag or marking with a legible waterproof paint or ink. Employers whose employees speak languages other than English may add to the tag the translation of the acronym "NORM" in those languages as long as the acronym "NORM" is also on the tag. (b) Within six months of the effective date of this rule, each person whom the Commission has notified that the person owns or operates NORM-contaminated equipment shall, on each lease that is the subject of the Commission notice, identify NORM-contaminated equipment with the letters "NORM" by securely attaching a clearly visible waterproof tag or marking with a legible waterproof paint or ink. Employers whose employees speak languages other than English may add to the tag the translation of the acronym "NORM" in those languages as long as the acronym "NORM" is also on the tag. (TAC Title 16:1 Chapter 4.F §4.605)

C. Worker Protection Standards (TAC Title 16:1 Chapter 4.F §4.608)

   a. Any employer of persons engaged in activities involving the disposal of oil and gas NORM waste shall comply with applicable provisions, as determined by TDH, of 25 TAC §289.202 (relating to Standards for Protection Against Radiation from Radioactive Material) adopted effective October 1, 2000, including but not limited to:

      i. (1) implementing a radiation protection program as provided in 25 TAC §289.202(e);

Table 2.7 (continued)

ii. (2) controlling the occupational dose to all employees as provided in 25 TAC §289.202(f) - (m);

iii. (3) conducting surveys and monitoring as provided in 25 TAC §289.202(p) and (q);

iv. (4) assuring respiratory protection and implement controls to restrict internal exposure in restricted areas as provided in 25 TAC §289.202(v) - (x);

v. (5) posting signs and labels as provided in 25 TAC §289.202(z) - (dd);

vi. (6) keeping records of radiation protection programs and of special exposures as provided in 25 TAC §289.202(ll) - (nn), (pp) - (rr), and (vv); and

vii. (7) keeping reports as provided in 25 TAC §289.202(ww) - (zz) and (aaa).

D. Disposal Methods (TAC Title 16:1 Chapter 4.F §4.614)

a. Disposal of oil and gas NORM waste other than produced water by discharge to surface or subsurface waters, as defined in §3.8 of this title (relating to Water Protection), shall be prohibited. Disposal of oil and gas NORM waste by spreading on public or private roads also shall be prohibited. (TAC Title 16:1 Chapter 4.F §4.611)

b. A person may dispose of oil and gas NORM waste by placing it between plugs in a well that is being plugged and abandoned, provided that:

i. (1) No person may dispose of oil and gas NORM waste at a lease or unit other than the lease or unit where the oil and gas NORM waste was generated unless prior to commencement of disposal operations, the surface owner of the lease or unit where the disposal occurs provides written consent for the disposal.

ii. (2) The oil and gas NORM waste shall be placed in the well at a depth at least 250 feet below the base of usable quality water in compliance with §3.14 of this title (relating to Plugging).

iii. (3) If the oil and gas NORM waste is encased in a tubing string, the tubing shall be: (A) placed, not dropped, in the well; and (B) left with an assembly that allows ready retrieval, if the string is not secured in cement.

iv. (4) A cement plug shall be set immediately above the oil and gas NORM waste and the plug shall be either: (A) above a cement retainer; (B) above a cast iron bridge plug; or (C) tagged to locate its position.

v. (5) The cement of the surface plug shall be color dyed with red iron oxide.

vi. (6) A permanent marker that shows the three-bladed radiation symbol specified in 25 TAC §289.202(z) (relating to Standards for Protection Against Radiation from Radioactive Material), adopted effective October 1, 2000, without regard to color, shall be welded to the steel plate at the top of the well casing.

vii. (7) The operator shall state on Form W-3A, Intent to Plug and Abandon: (A) the physical nature (such as pipe scale, contaminated soil, basic sediment, equipment, pipe, pumps, or valves) of the oil and gas NORM waste; (B) the volume of oil and gas NORM waste; (C) the radioactivity level of the oil and gas NORM waste (in pCi/g of Radium-226 combined with Radium-228 and any other NORM radionuclides for soil or other media (such as pipe scale, contaminated soil, basic sediment, etc.), or in µR/hr for equipment (such as pipes, pumps and valves); (D) the operator(s) of the lease, unit, or facility at which oil and gas NORM waste was generated; and (E) the source(s), if known, of the oil and gas NORM waste by Commission district; field; lease, unit, or facility; and producing formation.

Table 2.7 (continued)

viii. (8) If the oil and gas NORM waste is encased in tubing, the operator shall state on Form W-3A, Intent to Plug and Abandon: (A) the size, grade, weight per foot, and outside diameter of the tubing; (B) the subsurface depth of both the top and bottom of the tubing; (C) the diameter of the retrieval assembly; and (D) whether the tubing is free in the hole or is secured by cement, a bridge plug, or a cement retainer.

ix. (9) The operator shall submit Form W-3A to the Commission's district office for the location of the oil and gas NORM waste disposal site.

c. (c) Burial. Except as otherwise provided in this subsection, a person may dispose of oil and gas NORM waste by burial at the same site where the oil and gas NORM waste was generated, provided that, prior to burial, the oil and gas NORM waste has been treated or processed such that the radioactivity concentration does not exceed 30 pCi/g Radium-226 combined with Radium-228 or 150 pCi/g of any other NORM radionuclide within the treated or processed waste. Such treatment or processing, if it occurs at the disposal site, is considered to fall within the definition of disposal because it is necessary to facilitate disposal. This subsection does not authorize any person to bury NORM-contaminated equipment.

d. (d) Landfarming. A person may dispose of oil and gas NORM waste at the same site where the oil and gas NORM waste was generated by applying it to and mixing it with the land surface, provided that after such application and mixing the radioactivity concentration in the area where the oil and gas NORM waste was applied and mixed does not exceed 30 pCi/g Radium-226 combined with Radium-228 or 150 pCi/g of any other radionuclide.

e. (e) Disposal at a licensed facility. A person may dispose of oil and gas NORM waste at a facility that has been licensed by the United States Nuclear Regulatory Commission, the State of Texas, or another state if such facility is authorized under its license to receive and dispose of such waste.

f. (f) Injection. Injection of oil and gas NORM waste that meets exemption criteria of 25 TAC §289.259 (relating to Licensing of Naturally Occurring Radioactive Materials (NORM)), as a result of treatment or processing at a facility licensed by the TDH (hereinafter referred to as a "specifically licensed facility") into a well permitted under §3.9 of this title (relating to Disposal Wells) is authorized under this section, provided that the requirements of this subsection are met.

i. (1) Prior to injecting treated or processed oil and gas NORM waste, the operator of the injection well shall notify the Commission in writing that the operator plans to inject oil and gas NORM waste that meets the exemption criteria of 25 TAC §289.259 as a result of treatment or processing at a specifically licensed facility. The operator shall include a copy of the TDH license for each facility where oil and gas NORM waste that will be injected is treated or processed in order to meet the exemption criteria of 25 TAC §289.259.

ii. (2) Prior to injecting oil and gas NORM waste that has been treated or processed to meet the exemption criteria of 25 TAC §289.259, the injection well operator shall verify that the waste meets the exemption criteria by obtaining from the specifically licensed facility documentation regarding NORM surveys or other analyses conducted to ensure that the treated or processed oil and gas NORM waste meets the exemption criteria of 25 TAC §289.259.

E. If oil and gas NORM waste exceeds 30 picocuries per gram (pCi/gm) or less of radium-226 or radium-228 in: (I) soil, averaged over any 100 square meters (m^2) and averaged over the first 15 centimeters (cm) of soil below the surface; or (II) other media; or (ii) 150 pCi or less per gram of any other NORM radionuclide in: (I) soil, averaged over any 100 m^2 and averaged over the first 15 cm of soil below the surface, provided that these concentrations are not exceeded; or (II) other media, provided that these concentrations are not exceeded, it is then subject to the regulations of 25 TAC §289.259.

a. Equipment, buildings, and structures contaminated with NORM in excess of the levels set forth in subsection (w) of this section and equipment not otherwise exempted under the provisions of subsection

Table 2.7 (continued)

(d)(2) and (3) of this section shall not be released for unrestricted use. The decontamination of equipment, buildings, and structures as described in subsection (i)(2) of this section shall be performed only by persons specifically licensed by the agency or another licensing state to conduct such work, including contractors of a general licensee, except that a general licensee or a contractor under the control and supervision of a general licensee can perform routine maintenance on equipment, buildings, and structures owned or controlled by the general licensee. (Maintenance that provides a different pathway for exposure than is found in daily operations and that increases the potential for additional exposure is not considered routine.) Persons conducting activities specified in subsection (i)(2) of this section and working as a contractor under the control and supervision of a general licensee must possess a specific license issued by the agency in accordance with subsection (k) of this section.

i. Section (i) decontamination description:

    1. 1) Unless otherwise exempted under the provisions of subsection (d) of this section or licensed under the provisions of §289.252 of this title, the manufacture and commercial distribution of any material or product containing NORM shall be specifically licensed in accordance with this section or in accordance with the equivalent requirements of another licensing state.

    2. (2) Persons conducting deliberate operations to decontaminate the following shall be specifically licensed in accordance with the requirements of this section: (A) buildings and structures owned, possessed, or controlled by other persons and contaminated with NORM in excess of the levels set forth in subsection (w) of this section; or (B) equipment or land owned, possessed, or controlled by other persons and not otherwise exempted under the provisions of subsection (d) of this section.

    3. (3) Unless otherwise exempted in accordance with subsection (d) of this section, persons receiving NORM waste from other persons for storage or processing or persons who process NORM for other persons at temporary job sites shall be specifically licensed in accordance with the requirements of this section.

    4. (4) Spinning pipe gauge licensees performing reclamation activities shall obtain specific authorization to perform NORM decontamination on pipe. Alternatively, spinning pipe gauge licensees may survey tubing before reclamation activities are performed. If the exposure rate on the outside of a pipe, measured at any accessible point, is greater than 50 μR/hr, then the spinning pipe gauge licensee shall obtain a NORM decontamination license. If the exposure rate of the pipe measures less than 50 μR/hr, a spinning pipe gauge licensee may perform the scale removal activity without additional authorization on their license.

b. (3) The handling or processing by a general licensee of NORM-contaminated materials not otherwise exempted from the requirements of this section for the purpose of recycling is authorized by the agency if the radiation level 18 inches from the NORM-contaminated material does not exceed 2 millirem per hour (mrem/hr).

c. (4) The transfer of NORM not exempt from the requirements of this section from one general licensee to another general licensee is authorized by the agency if the: (A) equipment, buildings, and structures contaminated with NORM are to be used by the recipient for the same purpose or at the same site; (B) materials being transferred are ores or raw materials for processing or refinement; or (C) materials being transferred are in the recycling process.

(25TAC 25 TAC §289.259 (f))

10. Storm Water Best Management Practices for Sites with Greater Than 1 Acre of Total Disturbance

References:

- Texas Administrative Code, Title 16 Economic Regulation, Part 1 Railroad Commission of Texas, Chapter 3 Oil and Gas Division; http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3

- Railroad Commission of Texas, 5/22/1009. Barnett Shale Information. http://www.rrc.state.tx.us/barnettshale/index/php

General: "The Commission's regulations ensure the quality of waters (and land) that could be potentially impacted by an oil and gas operator's activity. The Commission's current rules defines 'pollution of surface or subsurface water' broadly: 'The alteration of the physical, thermal, chemical, or biological quality of, or the contamination of, any surface or subsurface water in the state that renders the water harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.'" (RRC, Barnett Shale Information)

Table 2.8
Fort Worth, Texas Regulatory Survey

Agency: City of Fort Worth, Texas

Regulations, Acts, and Laws:

- City of Fort Worth Ordinance Number 18449-02-2009
- Code of Ordinances, City of Fort Worth, Texas, Chapter 15, Article II

References:

- City of Fort Worth, Gas Wells, 5/23/2009. http://www.fortworthgov.org/gaswells/
- http://www.fortworthgov.org/gaswells/
- City of Fort Worth, Texas, Code of Ordinances, Part II, Chapter 15, Article II, §§15-34 – 15-40; http://www.municode.com/resources/gateway.asp?pid=10096&ekmensel=c582fa7b_21_0_btnlink
- City of Fort Worth, Texas, Code of Ordinances, Part II, Chapter 15, Article II, §§15-42 – 15-45; http://www.municode.com/resources/gateway.asp?pid=10096&ekmensel=c582fa7b_21_0_btnlink

1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

A. Regulations:

1. Ordinance Number 18449-02-2009, § 15-42, A. On site Requirements: 3) Closed Loop Mud Systems (CLMS): required for all drilling and reworking operations for all gas wells

   Exceptions:

   - Gas wells on an open space of >/= 25 acres with no operations within 1000 ft. of a Protected Use (PU) - residence, religious institution, hospital building, school, or public park – may use a lined earthen pit.
   - Lined earthen mud or circulating pits may be used for gas wells permitted prior to January 2009. (Ordinance Number 18449-02-2009, § 15-42, A. 27)

2. Ordinance Number 18449-02-2009, § 15-42, A. On site Requirements: 27) Pits: requirements for pits used for drilling and completion operations
3. Ordinance Number 18449-02-2009, § 15-42, A. On site Requirements: 5) Discharge: may not deposit or discharge any refuse, including wastewater or brine, from any gas operation into or upon any public roads, lots, drains, sewers, or ditches without City permits, any body of water, any private property
4. Ordinance Number 18449-02-2009, § 15-42, A. On site Requirements: 16) Fracturing Operations: well cannot flow or vent directly to the atmosphere without first passing through separation equipment or into a portable tank
5. Ordinance Number 18449-02-2009, § 15-42, A. On site Requirements: 17) Freshwater Fracture Ponds vi: Pit Requirements
6. Ordinance Number 18449-02-2009, § 15-42, A. On site Requirements: 39) Waste Disposal

Table 2.8 (continued)

7. Ordinance Number 18449-02-2009, § 15-42, A. On site Requirements: 27) Pits: Requirements for pits used for drilling and completion operations

B. Tank Requirement

1. Required when a CLMS is required (§ 15-42, A. 3&27)

2. Required during fracturing for separation and storage to prevent direct flow or venting (§ 15-42, A. 16)

3. Liquid hydrocarbon storage: portable, closed, steel, storage tanks that meet API standards; must have vent line, flame arrester, and pressure release valve and must be enclosed by a fence (§ 15-42, A. 39)

C. Pit Construction Specifications

1. Volume: No information

2. Location / Setbacks:

   a. Fresh water pits: may not be placed in any city-recognized drainage way, FEMA floodplain or floodway, existing city rights-of-way or city easements (§ 15-42, A. 17)

   b. Fracture ponds located on a tract of land not adjacent to a gas drilling pad site shall be located in agricultural (AG), light industrial (I), medium industrial (J), and heavy industrial (K) zones

   c. Drill pits may not be in a floodplain without a floodplain development permit from the Transportation and Public Works Department.

3. Freeboard: No information

4. Separation: No information

5. Depth of Bottom: No information

6. Subbase / Subgrade: No information

7. Slopes: No information

8. Surface Water Diversion: No information

9. Protection: fresh water fracturing pit must be enclosed with open design chain link, black or dark green fencing on all four sides. (§ 15-42, A. 17 vi)

   Drill pits will be fenced on all open sides during drilling operations and enclosed with a chain link fence on all 4 sides after drilling operations have ceased, (§ 15-42, A. 27 vi)

10. All drill pits must be approved by the City.

D. Pit / Impoundment Liner Specifications: Freshwater fracture pits shall not be lined with a synthetic, impervious liner. (§ 15-42, A. 17 vi)

   Exception: Approved by the city gas inspector.

1. Coefficient of Permeability: No information

Table 2.8 (continued)

2. Thickness / Strength: No information

3. Composition: No information

4. Seams: No information

E. Land Application Specifications

1. Requires city permits / Gas Inspector's approval

2. may not deposit or discharge any refuse, including wastewater or brine, from any gas operation into or upon any public roads, lots, drains, sewers, or ditches without City permits, any body of water, any private property (§ 15-42, A. 5)

3. Location: No information

4. Depth to Seasonal High GW Table: No information

5. Subgrade: No information

6. Slopes: No information

F. Pit and Waste Removal and Disposal

1. General waste regulations (§ 15-42, A. 39):

    a. All disposals must follow the Texas Railroad Commission (TRC) rules and other appropriate local, state, and federal agency rules (including air and water pollution control regulations).

    b. Waste transported to an off-site facility at least every 30 days (unless otherwise directed by TRC). Water stored in tanks shall be removed as necessary.

2. Existing liners - shall be removed when a fresh water pit is reworked, enlarged, restored or altered. (§ 15-42, A. 17 vi).

3. Waste Toxicity Limits:

4. Disposal in Pit: No oil and gas waste by-products or salt water shall be allowed in the fresh water fracture pit. (§ 15-42, A. 17 vi).

5. Land Application: City permit required

6. Liquid Fraction Disposal

    a. using a fresh water pit for the disposal of liquids other than fresh water requires city permits / Gas Inspector's approval.

    b. may not deposit or discharge any refuse, including wastewater or brine, from any gas operation into or upon any public roads, lots, drains, sewers, or ditches without City permits, any body of water, any private property (§ 15-42, A 5)

c. No flowback water produced by fracture operations shall be placed in an open pit without a state permit submitted to the Gas Inspector

7. Solid Fraction Disposal and Encapsulation or Application: No information

8. Liquids and Solids

a. all drill pits and contents must be dewatered, backfilled and compacted following the state-wide rules of the Railroad Commission

b. no drill cuttings, rotary mud, or wastewater generated during drilling operations may be buried on site unless permitted by the Railroad Commission and approved by the City after a pre-burial test

G. Reclamation of Disposal Area: The operator and surface owner shall have an agreement providing for the maintenance and operation of a fracture pit when the pond is no longer in use by the operator, or the operator will return the property to its pre-pit condition. (§ 15-42, A. 17 vi).

2. Water Well Testing Requirements

A. Regulations: Ordinance Number 18449-02-2009, § 15-42, A. 18) Fresh Water Wells i.

B. Pre-Drilling Testing Requirements:

1. Quality: water analysis for existing fresh water wells within 500’ of the gas well

2. Quantity: measure flow rate for existing fresh water wells within 500’ of the gas well

C. Pre-Drilling Testing Recommendations: NA.

D. Post-Drilling Testing Requirements:

1. Quality: water analysis for existing fresh water wells within 500’ of the gas well

2. Quantity: measure flow rate for existing fresh water wells within 500’ of the gas well

E. Post-Drilling Testing Recommendations: NA

3. Fracturing Fluid Requirements and Fluid Use and Recycling - **No information**

4. Hydraulic Fracturing Operation Requirements

A. Regulations: Ordinance Number 18449-02-2009, Chapter 15, Article II, Division V, VII

B. Gas Well Permit (and permit fee)

1. Expires if drilling has not begun within 365 days

Exceptions: extended for another 365 days (by Gas Inspector) if:

- prove there are no new PUs within 600’
- requested before expiration date of original permit

Table 2.8 (continued)

- new extended expiration is not beyond the expiration date of the current Texas Railroad Commission permit

2. Required for the drilling of each additional well at a MWS under the original MWS
3. Includes:
   a. property location description; map showing proposed routes; and surveyed, detailed site plan
   b. city-wide road maintenance agreement
   c. location and description of all improvements and structures and the owners (addresses) within 600’ of the well (structures) or drill site (owners).
   d. erosion control and grading plan (city-approved)
   e. water source description
   f. Storm Water Pollution Prevention Plan
   g. determination by the Texas Commission on Environmental Quality (TCEQ) of the depth of usable quality ground water
   h. insurance and security requirements
   i. city reviews and approvals
   j. fracture pond permit / approval
   k. surface reclamation plan
   l. proposed pipeline route
   m. noise management plan
   n. approved Railroad Commission drilling permit and attachments

C. Written notice to city Gas Inspector and sign posted at least 10 days before reworking a well with a rig (incl. fracture stimulation)

D. Drilling Notice to Gas Inspector 48 hours before drilling operations, fracture stimulation, work over or servicing operations (§15-42 A3)

E. Flood plain Development Permit (waiver)

1. Necessary if proposed site is within a FEMA floodplain or floodway
2. Agency: City of FW Transportation and Public Works Department

F. Multiple Well Site Permit (MWSP): operator may request MWSP when he submits an application for a single well permit

1. All setback measurements made from pad site boundary line

2. Must include information about all parcels within 1000’ of the MWS

3. Gas Well Permit required prior to drilling each additional well

4. All additional wells on a MWS must comply with all regulations

   Exception: Subsequent wells on permitted MWS need no variance / waiver for distance setback from PU, but no well closer than 300’ from PU or public building

   No variance or waiver for a distance setback is required

G. Notifications:

   1. Publish newspaper notice for initial gas well permit (see also section 15-36 of above ordinance)

   2. Include in notice if a MWS Permit has been filed

   3. Post signage at site prior to activity

H. Gas Drilling Review Committee (GDRC) application review required if:

   1. City Council waiver required

   2. Non commercial truck routes are involved

   3. Application involves pipelines or pipeline facilities in a private residential area.

I. Blowout Prevention

J. Closed Loop Mud Systems

   Exception: Gas wells on an open space of >/= 25 acres with no operations within 1000 ft. of a Protected Use (PU) - residence, religious institution, hospital building, school, or public park – may use a lined earthen pit.

5. Noise and Light Impact Minimization and Mitigation

A. Regulations:

   1. Ordinance Number 18449-02-2009, § 15-42, A. On Site Requirements

   2. Ordinance Number 18449-02-2009, § 15-42, B. Noise – Gas Wells

B. By Activity, Noise and Light:

   1. Drilling and Operating – conducted to minimize vibration and in accordance with best accepted practices for gas production. Equipment (incl. gas lift compressors) shall be constructed and operated to minimize vibration and annoyances. Proven technological improvements will be used if they minimize vibration. (§ 15-42, A. 8 & 19)

   2. Fracturing – conducted between 6:00 a.m. and 7:00 p.m. (§15-42, A. 16 i)

   3. Flowback Operations - Exempt from work hour restrictions (§15-42, A. 16 iii)

Table 2.8 (continued)

4. Well Testing
5. Flaring site (§15-42, A. 29)
   a. must be performed at least 300’ from any building that is not part of the site
   b. screen flame to minimize disturbing effects to adjacent property owners
6. Drill Stem Testing - conducted between 6:00 a.m. and 7:00 p.m. (§15-42, A. 7)
7. Construction Activities (excavation of , alteration to, or repair work on any access road or pad site) - conducted between 6:00 a.m. and 7:00 p.m., Mon - Sat, not on Sunday (§15-42, A. 7)
8. Truck deliveries – limited to 6:00 a.m. to 7:00 p.m., Mon – Sat, except in cases of fires, blowouts, explosions, and other emergencies and instances when the delivery of equipment is necessary to prevent the cessation of drilling or production.
9. Mobilization and Demobilization – prohibited before 9:00 a.m. and after 6:00 p.m. on Sundays (§15-42, A. 25)
10. Workover operations (work after a well’s completion to secure, restore, or increase production) - restricted to 6:00 a.m. to 7:00 p.m., Mon – Sat (§15-42, B. 5)
11. Sunday Work Allowances and Hours - Only mobilization, demobilization, and advancing the borehole will be allowed on well sites on Sundays. Sunday hours are restricted to 9:00 a.m. to 6:00 p.m. (§15-42, A. 25 & 42)

C. Noise:

1. A Gas Well Permit requires the submission of a noise management plan that
   a. Identify noise impacts
   b. Establish the Ambient Noise Level (ANL) – continuous, 72-hour, pre-drilling measurement including at least one 24-hour reading over a Saturday or Sunday
   c. Detail mitigation
2. Noise Level increase limits (measured at Protected Use receptor’s property line, the closest exterior point of the PU structure or inside the PU structure)
   a. 6:00 a.m. to 7:00 p.m., Mon – Sat (day): 5 decibels over ANL
   b. 7:00 p.m. to 6:00 a.m., Mon – Sat (night): 3 decibels over ANL (includes night flowback operations)
   c. Fracturing Operations (day only): 10 decibels over ANL
3. Adjustments to the noise standards/levels in subsection 2 may be permitted intermittently in accordance with the following:
   a. Permitted increase: 10 dBA for 5 minutes (cumulative) during any 1 hour
   b. Permitted increase: 15 dBA for 1 minute (cumulative) during any 1 hour
   c. Permitted increase: 20 dBA for less than 1 minute (cumulative) during any 1 hour

Table 2.8 (continued)

4. Noise Standards based on frequency (measured at Protected Use receptor's property line, the closest exterior point of the PU structure or inside the PU structure)

   a. May not cause noise which creates pure tones where 1/3 octave band sound-pressure level in the band with the tone exceeds the arithmetic average of the sound-pressure levels of 2 contiguous 1/3 octave bands by 5 dB for center frequencies of 500 Hertz and above, and by 8 dB for center frequencies between 160 and 400 Hertz, and by 15 dB for center frequencies less than or equal to 125 Hertz; or

   b. Creates low-frequency outdoor noise levels that exceed the following dB levels:

      16 Hz octave band: 65 dB

      32 Hz octave band: 65 dB

      64 Hz octave band: 65 dB

5. Specific Equipment Limitations:

   a. Compressor Stations:

      i. Max, permitted, sound levels for all permanent compressors by Zone classification

         - Industrial: 75 dBA day / 65 dBA night
         - Commercial: 65 dBA day / 55 dBA night
         - Residential: 55 dBA day / 50 dBA night
         - Boundary between 2 zones: lower noise level std applies

      ii. May raise ANL by showing that the actual ambient is greater than allowed. Actual ambient (measured at the property line of the noise creator) becomes the new ambient for the location.

          Exception: residential zoning – requires a special exception by the Board of Adjustment to raise the ANL

6. Noise Monitoring:

   a. The exterior noise level generated by operations of all gas wells located within 600 feet of a protected use shall be continuously monitored, to ensure compliance.

   b. If a complaint is received by either the operator or the gas inspector from any protected use the operator shall, within 24 hours of notice of the complaint, continuously monitor the exterior noise level generated by the operations for 72 hours.

7. Mitigation: Acoustical blankets, sound walls, mufflers or other alternative methods as approved by the gas inspector and the city fire department

8. Non-compliance: If the operator is in compliance with the noise management plan, and a violation still occurs, the operator will be given 24 hours from notice of non-compliance to correct the violation before a citation is issued. Additional extensions of the 24- hour period may be granted if the source of the violation cannot be identified.

Table 2.8 (continued)

D. Light: Well site and drill rig lighting, to the extent practicable and safe, shall be directed downward and internally to avoid glare on public roads and adjacent dwellings and buildings within 300'. (§15-42, A. 24)

6. Setbacks

A. Regulations:

1. Ordinance Number 18449-02-2009, Chapter 15, Article II, Division V, §15-34, L. Multiple Well Site Permit

   Exceptions:

2. Ordinance Number 18449-02-2009, Chapter 15, Article II, Division VII, §15-42, A. 18

   Exceptions:

   - the owner or Protected Use (PU) has given consent
   - City grants variance

3. Ordinance Number 18449-02-2009, Chapter 15, Article II, Division VII, §15-42, C.

B. Setback Reference Points:

1. well pad boundary line for multiple well sites (MWS) (unless noted) (§15-34, L)
2. well bore center at ground surface, in a straight line, to the closest point of the building, item or boundary for single well sites

C. Specific Setbacks from (Distances measured from the well bore, in a straight line, to the to the closest exterior point of any object listed, unless otherwise noted):

1. all existing fresh water wells: 200' (from closest well bore to the fresh water well bore)

   Exceptions:

   - may drill a fresh water well to supply water for drilling and completion operations within 200' of well bore. The supply well is excluded from the 200' setback for future wells on the permitted pad site.
   - unless the water well owner has signed a waiver

2. domestic supply springs: no information
3. surface water body or wetland: no information
4. private dwellings: see 7, this subsection
5. Protected Use (residence, religious institution, hospital building, school, public park):

   a. 600' from pad boundary for multiple well site or from well bore for single well site

      Exception:

Table 2.8 (continued)

- Measurement from a wellbore to a school not located within another Protected Use shall be from the school's property line.

- City Council waiver or notarized waiver granted by all PU owners within 600' of the proposed well, but setback never less than 300'.

b. Subsequent wells on permitted MWS need no variance / waiver for distance setback from PU, but no well closer than 300' from PU or public building

6. Public Building: 300', never less

7. Habitable Structure: 200'

8. building accessory to, but not necessary to, the operation of the well: 100'

9. any property line or outer pad site boundary: 75'

10. storage tank or ignition source: 25'

D. Setback Revisions based on drilling duration, fracturing fluid volume, and number of wells at one pad: Included in subsection C, above.

7. Multi-Well Reclamation – No information

8. Storm Water Best Management Practices for Sites with Greater Than 1 Acre of Total Disturbance – No information

Table 2.9
West Virginia Regulatory Survey

Agency: Gas Drilling is regulated by the Department of Environmental Protection, Office of Oil and Gas and West Virginia Oil and Gas Conservation Commission

- West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments, Draft, March 13, 2009 http://www.wvdep.org/Docs/16782_Industry%20Marcellus%20Guidance%20Document.pdf
- West Virginia Erosion and Sediment Control Manual http://www.wvdep.org/Docs/9058_Erosion%20and%20Sediment%20Control%20Field%20Manual.pdf
- Letter from Cabinet Secretary Randy C. Huffman to Large Volume Pit/Pond Operators, December 16, 2008 http://www.wvdep.org/Docs/16191_Large%20Volume%20Pit%20Inspection%20Directive.pdf
- West Virginia Code §22 http://www.legis.state.wv.us/WVCODE/Code.cfm?chap=22&art=1
- West Virginia Legislative Rule Title 35 http://www.wvsos.com/csr/rules.asp?Agency=Oil%20&%20Gas
- West Virginia Administrative Law Title 39 http://www.wvsos.com/csr/rules.asp?Agency=Oil%20&%20Gas
- West Virginia DEP General Water Pollution Control Permit GP-WV-1-88
- West Virginia DEP Permit No. GP-WV-1-07 General Water Pollution Control Permit
  Factsheet:http://www.wvsoro.org/resources/12888_CBMRevised_Fact_Sheet_CBM_Permit_4-17-07.pdf
  Form: http://www.wvsoro.org/resources/12947_CBM%20Produced_Water_Permitregistration_4-17-07.pdf

1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

A. Regulations

1. Proper design and installation of pits should be in such a manner as to provide structural integrity for the life of the pit. (West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Draft 3/13/09))

2. Before drilling begins, the operator must develop a "Construction and Reclamation Plan", Form WW-9 (West Virginia Erosion and Sediment Control Manual)

3. The operator will be required to conduct regular inspections of all pits and ponds with a capacity greater than 5000 bbl (West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Draft 3/13/09); Letter from Cabinet Secretary Randy C. Huffman to Large Volume Pit/Pond Operators, 12/16/08)

4. All field constructed pits which are used to contain waste water shall meet the following minimum requirements:
   a. Any pit shall be constructed and maintained so as to prevent seepage, leakage or overflows and to maintain its integrity.
   b. Provisions shall be made for diverting surface water from the pits.
   c. When an operator is unable to maintain adequate freeboard to prevent overflow from any pit, the district inspector shall be notified by the well operator and an additional pit (or alternative overflow facility) shall be constructed under the supervision of the chief which shall also meet the requirements specified in W. Va. Administrative Law §35-3-14.4

   d. If existing soil is not suitable to prevent seepage or leakage, other materials which are impervious shall be used as a liner for a pit. Any such liner shall be installed in such a manner as to protect the structural integrity of both pit and liner
   e. Dikes associated with pits shall be constructed of compacted material and maintained with a slope that will preserve the structural integrity of such dike.
   f. Any unlined dike constructed of existing soil shall be free of trees and other organic matter, large rocks, or any other material which could be reasonably expected to adversely affect the structural integrity of such dike.
   g. Reclamation of the pits shall not cause an overflow or unpermitted discharge of materials to waters of the state.
   h. All drilling pits and alternative overflow prevention facilities shall be constructed, maintained and reclaimed as required by those conditions of any permit issued by the chief pursuant W. Va. Code §22-6-7 and subsection 14.5 of W. Va. Administrative Law §35-3, and so as not to be left in such condition as to constitute a hazard or to prevent use of the surface for agricultural purposes after the expiration of the six month or extended period for reclamation prescribed by W. Va. Code §22-6-30

5. Collection, storage and discharge of water, fluids, or other wastes in connection with the drilling or operation of CBM wells shall be pursuant to a permit issued by the chief in accordance with W. Va. Code §22-6-7

B. Pit Size and Acreage Disturbance

1. Construction and Reclamation plan must provide an estimate of the amount of acreage disturbed, location of all pits with approximate dimensions of the drill site and pits, and the land application if applicable (West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Draft 3/13/09))

2. Construction plan must be clear, concise, and complete so all parties involved understand the proposed activity. (West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Draft 3/13/09))

3. Pit should be at least 75 ft from the well head (Figure II-12 from West Virginia Erosion and Sediment Control Manual)

C. Pit Removal and Reclamation Requirements

1. Within six months after the completion of the drilling process, the operator shall fill all the pits for containing muds, cuttings, salt water and oil that are not needed for production purposes, or are not required or allowed by state or federal law or rule and remove all concrete bases, drilling supplies and drilling equipment. Within such period, the operator shall grade or terrace and plant, seed or sod the area disturbed that is not required in production of the well where necessary to bind the soil and prevent substantial erosion and sedimentation. No pit may be used for the ultimate disposal of salt water. Salt water and oil shall be periodically drained or removed, and properly disposed of, from any pit that is retained so the pit is kept reasonably free of salt water and oil. (W. Va. Code §22-6-30a)

2. Within six months after a well that has produced oil or gas is plugged, or after the plugging of a dry hole, the operator shall remove all production and storage structures, supplies and equipment, and any oil, salt water and debris, and fill any remaining excavations. Within such period, the operator shall grade or terrace and plant, seed or sod the area disturbed where necessary to bind the soil and prevent substantial erosion and sedimentation.
   a. The director may, upon written application by an operator showing reasonable cause, extend the period within which reclamation shall be completed, but not to exceed a further six-month period. If the director refuses to approve a request for extension, the refusal shall be by order.

   (W. Va. Code §22-6-30b)

Table 2.9 (continued)

3. It shall be the duty of an operator to commence the reclamation of the area of land disturbed in siting, drilling, completing or producing the well in accordance with soil erosion and sediment control plans approved by the director or the director's designate. (W. Va. Code §22-6-30c)

4. The director shall promulgate rules setting forth requirements for the safe and efficient installation and burying of all production and gathering pipelines where practical and reasonable except that such rules shall not apply to those pipelines regulated by the public service commission (W. Va. Code §22-6-30d)

D. Solid Waste Disposal

1. Solid waste will be properly disposed of in a solid waste facility that is permitted to receive waste from exploration, development, production, storage and recovery of oil and gas and related mineral resources in this state. (W.Va Legislative Rule 35CSR2)

E. Liquid Fraction Disposal

1. Underground Injection – surface application is not an option due to the quality and quantity of waste water (Guidelines draft 3/13/09)

2. Salt water and oil shall be periodically drained or removed, and properly disposed of, from any pit that is retained so the pit is kept reasonably free of salt water and oil. (W. Va. Code §22-6-30a)

3. Land application of drilling wastewaters in accordance with general water pollution control permit GP-WV-1-88

2. Water Well Testing Requirements

A. Obligations and Rights

1. At the request of the land owners as defined in W.Va Code §22-6-9, or an occupant of land within 1000 ft. of the proposed well, the operator shall sample and analyze water from any wells or springs within 1000 ft of the proposed well that is utilized by such owner or occupant for human consumption, domestic animals, or other general use. (Title 35 Legislative Rule, Division of Environmental Protection, Office of Oil and Gas, Series 4-Oil and Gas Wells and Other Wells §35-4-19.1a)

2. If there is no request, the operator shall sample and analyze water from any one known and existing well or spring within 1000 ft of the proposed well. If more than one such well or spring exists, the operator shall select for sampling and analysis the one well or spring that, in the operator's judgment, has the highest potential for being influenced by the operator's well work. (Title 35 Legislative Rule, Division of Environmental Protection, Office of Oil and Gas, Series 4-Oil and Gas Wells and Other Wells §35-4-19.1b)

3. If the operator is unable to sample and to analyze water from any such water wells or springs within 1000 ft of the proposed well, the chief may require the operator to sample and to analyze in accordance with this section water from one existing water well or spring located between 1000 and 2000 ft from the proposed well. (Title 35 Legislative Rule, Division of Environmental Protection, Office of Oil and Gas, Series 4-Oil and Gas Wells and Other Wells §35-4-19.1c)

4. At an operator's discretion, any or all water wells or springs within 1000 feet of the proposed well may be sampled and analyzed in accordance with this section. (Title 35 Legislative Rule, Division of Environmental Protection, Office of Oil and Gas, Series 4-Oil and Gas Wells and Other Wells §35-4-19.1d)

B. Notification Requirements

1. The operator shall give notice to the owner of record of the surface tract defined in W. Va. Code §22-6-9, of the right of the user who is either an owner or occupant to request the operator to sample and analyze a well or

Table 2.9 (continued)

spring in accordance with W. Va. Administrative Law §35-4-19.1a. The operator has satisfied this requirement if notice is provided by the same methods utilized in conjunction with the permit application. (W. Va. Administrative Law §35-4-19.2a)

2. The operator shall make responsible attempt to give additional notice of the right to request the operator to sample and analyzed a well or spring within 10000 feet of the proposed well. The operator will have satisfied this if notice is given by:
   a. Personal service or posting notice at the entrance of any dwelling within 1000 ft, and at any other location with 1000 ft of the proposed well where the use of water wells and springs is conspicuous
   b. Mailing the notice to dwellings within 1000 ft of the propose well, and posting at any other conspicuous water usage locations in 1000 ft
   c. Any other means reasonably calculated by the chief to provide adequate notice to the occupant/user (W. Va. Administrative Law §35-4-19.2b)

3. The notice given by the operator shall be approved by the chief, which, at a minimum, shall contain a statement of the user's right to require sampling and analysis, advise such users of the independent right to sample and analyze any water supply at the expense of the user, advise such users as to whether the operator will utilize an independent laboratory, or not, to analyze any sample, and to advise such users of the availability through the chief of a list of laboratories (W. Va. Administrative Law §35-4-19.2c)

4. For all wells, notice shall be given at least 48 hrs prior to the commencement of well drilling. For well drilling permitted after August 1, 1993, the operator shall provide such notice prior to the time of the filing of any permit application with the chief. (W. Va. Administrative Law §35-4-19.2d)

5. At the time of filing with the chief of the permit application for well drilling, the operator shall file with the chief a statement describing whether any such users were identified, and the manner in which any such users were provided with notice. (W. Va. Administrative Law §35-4-19.2e)

C. Sampling and Analysis

1. The operator shall collect and analyze samples in accordance with methods approved by the chief, or set forth at 40 CFR Part 136. (W. Va. Administrative Law §35-4-19.3a)

2. The operator shall analyze for the following parameters:
   a. pH, Fe, TDS, Cl, Detergents (MBAS), and any other parameters determined by the operator
   (W. Va. Administrative Law §35-4-19.3b)

3. The operator shall, no later than thirty days after receipt of such sample analysis, provide the results of such sample analysis in writing to the chief, and any of the users who may have requested such analysis in accordance with this section. (W. Va. Administrative Law §35-4-19.3d)

D. Water Remediation

1. The operator is liable for any reasonable actual damages done, other than normal wear and tear of the property, while gather the sample required. This provision does not limit other provisions of the law (W. Va. Administrative Law §35-4-19.4d)

2. Where the facilities or activities of an operator cause or contribute to the concentration of a certain constituent in groundwater, which exceeds standards of purity and quality for groundwater promulgated by the state Environmental Quality Board pursuant to W. Va. Code §22-12-5, every reasonable effort shall be made by the operator to identify, remove, or mitigate the source of such contamination. Within 30 days following written request by the chief, the operator shall submit to the chief a groundwater remediation plan to strive where practical to reduce the level of contamination over time to support drinking water use. Such a plan shall include such groundwater monitoring as may be necessary to demonstrate the effectiveness of the plan. (W. Va. Administrative Law §35-4-20.1)

Table 2.9 (continued)

3. Fracturing Fluid Requirements and Fluid Use and Recycling

A. Surface Water Use Restrictions and Regulations

1. Any removal of water greater than 750,000 gallons in a given month for one facility must register with the Division of Water and Waste Management. (W. Va. Code §22-26-3c).
    a. Registered persons that report withdrawals on an annual basis for a period of three consecutive years are not required to register further withdrawals unless the amount withdrawn annually varies by more than ten percent from the three year average. Altering locations of intakes and discharge points that result in an impact to the withdrawal of the water resource by an amount of ten percent or more from the consecutive three year average shall also be reported. (W. Va. Code §22-26-3h)
    b. Every person utilizing the state's water resources whose withdrawal from a water resource during any month exceeds 750,000 gallons, except those who purchase water from a public utility or other service that is reporting its total withdrawal, shall provide all requested information regarding withdrawals of a water resource. (W. Va. Code §22-26-3c)

2. Operators will be asked to provide information regarding the source(s) of withdrawals, volumes anticipated to be obtained, and the time of year of anticipated withdrawal prior to start-up.
    a. Water will, in no case, be withdrawn from ground or surface waters at volumes beyond what the waters can sustain
    b. Limit withdrawal during low flow to no more than 10% of a stream's flow
    c. Operators should seek larger stream sources for water supply, and avoid headwater streams during drier months, due to streams being at their lowest flows from July through November
    d. Contact the DEP for low flow information for the state's streams.
    e. Construction of centralized ponds for water storage may be appropriate during higher flow periods in preparation for low flow periods. Proper construction techniques can be obtained from the Dam Safety Office or the local Natural Resource Conservation Service field office.
    f. Stream access when pumping from them must be carefully considered. Boat launch ramps and other public access points could be damaged by excessive use and should be avoided.

    (West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Draft 3/13/09))

B. Treatment, Recycling, or Reuse Requirements for Drilling and Fracing Fluids

1. Underground Injection Control may be the best option
    a. Office of Oil and Gas issues Class II UIC permits for brine and fluid disposal

(West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Draft 3/13/09))

2. Operators should consider options for the recycling of fracture treatment flow-back fluid (West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Draft 3/13/09))

3. Transport frac fluids to local publicly owned treatment works.
    a. Office of Oil and Gas and the Division of Water and Waste Management must be notified, via application addendum of this option's consideration. DWWM will then contact the treatment facility to ensure that the facility can handle the flow and quality of waste
    b. Federal regulations prohibit on-site treatment and disposal of the frac fluid to nearby receiving streams.
    c. Transport and disposal at a centralized treatment facility can be an option

(West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Draft 3/13/09))

4. Due to the quality and quantity of the pit fluids, land application will not be a viable disposal option in many instances (West Virginia DEP, Industry Guidance, Gas Well Drilling/Completion, Large Water Volume Fracture Treatments (Draft 3/13/09))

Table 2.9 (continued)

5. It shall be unlawful for any person conducting activities which are subject to the requirements of this article, unless that person holds a water pollution control permit therefore from the director, which is in full force and effect to:
   a. Operate any disposal well for the injection or reinjection underground of any pollutant, including, but not limited to, liquids or gasses, or convert any well into such a disposal well or plug or abandon any such disposal well.

6. Land Application of Natural Gas Production Water from Coal Bed Methane Wells
   a. Listed below are regulated parameters and their maximum allowable levels:
      i. Chlorides - 1000 mg/l; Fe – 5 mg/l; Mn – 3.3 mg/l; Al – 2.5 mg/l; Sulfates – 1000 mg/l; TDS – monitor only; Volume of discharge is based on soil permeability as ponding or runoff into surface water is not allowed (West Virginia DEP Permit No. GP-WV-1-07 Part A)
   b. Discharges that will flow directly to a surface water body that is not part of the treatment process are prohibited. Discharges are prohibited within 1000 ft of a domestic water supply. (West Virginia DEP Permit No. GP-WV-1-07 Part G.1 and G.2)

4. Hydraulic Fracturing Operation Requirements

A. Permitting

1. Must complete appropriate permitting forms. (Checklist for filing a permit Section II, 9-01-00)
   a. WW-2B Form, and signed off by an inspector.
   b. WW-2A Form, as well as (1) including book and page and royalty percentage
   c. Surface Owner Waiver, Coal Owner/Lessee/Operator Waver
   d. WW-9 (pg. 1 and 2) with an inspector signature
   e. Reclamation Plan
   f. Mylar Plat
   g. Topography Map of the location for the well and pit
   h. Certified Mail Receipts or affidavit of person service
   i. Completion/Well Records of previous work
   j. Bond
   k. A Check for $650, if there is no pit then $550
   l. Worker's Comp/Employ.

2. All complete applications to be submitted to the Chief of the Office of Oil and Gas for a permit to drill, redrill, stimulate, operate, plug, abandon, deepen, case fracture, pressure, convert or combine any deep well, or physically change any deep well to allow the migration of fluid from one formation to another shall first be reviewed by the Commission or an authorized agent to ascertain compliance with this rule. (W. Va. Administrative Law 39CSR1-4.4)

3. Before drilling for oil or gas, or before fracturing or stimulating a well on any tract of land, the well operator shall have a plat prepared by a licensed land surveyor or registered engineer showing the district and county in which the tract of land is located, the name and acreage of the same, the names of the owners of adjacent tracts, the proposed or actual location of the well determined by survey, the courses and distances of such location from two permanent points or landmarks on said tract and the number to be given the well. (W. Va Code §22-6-12a)

4. A permit to drill, or to fracture or stimulate an oil or gas well, shall not be issued unless the application therefore is accompanied by a bond as provided in section twenty-six of this article. (W. Va Code §22-6-12c)

B. Pollution

1. If an oil and gas inspector, upon making an inspection of a well or well site or any other oil or gas facility, finds that any provision of this article is being violated, the inspector shall also find whether or not an imminent danger to persons exists, or whether or not there exists an imminent danger that a fresh water source or supply

will be contaminated or lost. If the inspector finds that such imminent danger exists, an order requiring the operator of such well or well site or other oil or gas facility to cease further operations until such imminent danger has been abated shall be issued by the inspector. If the inspector finds that no such imminent danger exists, the inspector shall determine what would be a reasonable period of time within which such violation should be totally abated. Such findings shall contain reference to the provisions of this article which the inspector finds are being violated, and a detailed description of the conditions which cause and constitute such violation. (W. Va. Code §22-6-3)

C. Notice to surrounding entities

1. Before fracturing any well the well operator shall, by registered or certified mail, forward a notice of intention to fracture such well to the director and to each and every coal operator operating coal seams beneath said tract of land, who has mapped the same and filed such maps with the office of miners' health, safety and training in accordance with chapter twenty-two-a of this code, and the coal seam owner and lessee, if any, if said owner of record or lessee of record has recorded the declaration provided in §22-6-36, and if said owner or lessee is not yet operating said coal seams beneath said tract of land. (W. Va. Code §22-6-13)
   a. If no objections are made, or are found by the director to such proposed fracturing within fifteen days from receipt of such notice by the director, the same shall be filed and become a permanent record of such fracturing, subject to inspection at any time by any interested person, and the director shall forthwith issue to the well operator a permit reciting the filing of such notice, that no objections have been made by the coal operators, or found thereto by the director, and authorizing the well operator to fracture such well.

5. Noise and Light Impact Minimization and Mitigation – None found, yet.

6. Setbacks

A. Adjacent Wells.

1. Each deep well drilled shall be not less than 3,000 feet from a permitted deep well location or from an existing well capable of producing hydrocarbons from the objective pool of the deep well. (W. Va. Administrative Law §39-01-4.2)

2. After the determination of a pool, the commission has the right to determine the area to be included in such spacing order and the acreage to be contained by each drilling unit, the shape thereof, and the minimum distance from the outside boundary of the unit at which a deep well may be drilled thereon. In accordance with W. Va Code §22C-9-7a.

3. An order establishing drilling units for a pool shall cover all lands determined or believed to be underlaid by such pool, and may be modified by the commission from time to time, to include additional lands determined to be underlaid by such pool or to exclude lands determined not to be underlaid by such pool. An order establishing drilling units may be modified by the commission to permit the drilling of additional deep wells on a reasonably uniform pattern at a uniform minimum distance to the nearest unit boundary as provided above. Any order modifying a prior order shall be made only after application by an interested operator and notice and hearing as prescribed herein for the original order: provided, that drilling units established by order shall not exceed 160 acres for an oil well or 640 acres for a gas well: Provided, however, that the commission may exceed the acreage limitation by 10% if the applicant demonstrates that the area would be drained efficiently and economically by a larger drilling unit. (W.Va. Code §22C-9-7(a-7))

B. Private Dwellings & Wells, and Outside Boundaries

1. No deep well shall be less than 400 feet from a lease or unit boundary. (W. Va. Code §39-01-4.2)

C. The Commission shall have the discretion to determine pattern location of deep wells adjacent to an area governed by special field rules where there is sufficient evidence to indicate that the pool or reservoir spaced by the special field rules may extend beyond the boundary of the spacing order and the uniformity of the spacing pattern is necessary to ensure orderly development of the pool or field. (W. Va. Code §39-01-4.2)

7. Multiple Well Pad Reclamation Practices-None Found, yet

8. NORM

9. Storm Water Runoff

A. Surface Runoff

1. Provisions shall be made for diverting surface water from the pits.

2. General Water Pollution Control Permit GP-WV-1-07 does not allow for ponding or runoff into surface water. Water quality protection should be provided for the designated uses of streams and waters near land application sites. (General Water Pollution Control Permit GP-WV-1-07, Part G)

3. Produced water discharge shall not include floating solids, visible foam, or free oil. (General Water Pollution Control Permit GP-WV-1-07, Part G)

Table 2.10
Wyoming Regulatory Survey

Agency: Gas Drilling is regulated by the Wyoming Oil and Gas Commission

- Wyoming Oil & Gas Conservation Commission Rules, April, 2008 http://wogcc.state.wy.us/rules-statutes.cfm?Skip='Y'

- Wyoming Statutes Annotated §30, Chapter 5 http://legisweb.state.wy.us/statutes/dlstatutes.htm

- Wyoming Department of Environmental Quality, Water Quality Rules and Regulations, Revised April, 2007 http://deq.state.wy.us/wqd/WQDrules/index.asp

- Wyoming State Engineer-Document #1795, Chapter 4 - Water for Highway or Railroad Roadbed Construction or Repair, Drilling for Oil or Gas, Exploring for Ore Bodies and Other Temporary Purposes, 3/5/1974 http://soswy.state.wy.us/Rules/RULES/1795.pdf

1. Pit/Impoundment Specifications and Drill Cutting, Waste, and Liner Disposal

A. Permitting and Application

1. Before drilling commences, approval to construct proper and adequate reserve pits for the reception and confinement of mud and cuttings and to facilitate the drilling operation shall be applied for and received in accordance with Chapter 4, Section 1. Special precautions, including but not limited to, an impermeable liner and/or membrane, monitoring systems, or closed systems, shall be taken, if necessary, to prevent contamination of streams and potable water and to provide additional protection to human health and safety in instances where drilling operations are conducted in close proximity to water supplies, residences, schools, hospitals, or other structures where people are known to congregate. (Wyoming Rules Chapter 3 §22.b)

2. Applications to construct pits, provided for in these rules, shall be approved if the pit will not cause the contamination of surface or underground water, and endanger human health or wildlife. Approval by the Commission of applications for permits for reserve or produced water pits does not relieve the owner or operator of the obligation to comply with the applicable federal, local, or other state permits or regulatory requirements. (Wyoming Rules Chapter 4 §1.a)

3. The Commission exercises its regulatory authority over the construction, location, operation, and reclamation of oilfield pits within a lease, unit or communitized area which are used solely for the storage, treatment, and disposal of drilling, production and treated unit wastes. The following pits are subject to this regulation: (i) reserve pits on the drilling location; (ii) reserve pits off the location within a lease, unit or communitized area permitted by owner or unit operator drilling the well; (iii) produced water retention pits, skim pits, and emergency production pits including the following: (A) pits associated with approved disposal wells which act as fluid storage, filtering or settling ponds prior to underground disposal in a Class II well; (B) pits constructed for disposal of produced fluids in connection with oil and gas exploration and production used as part of the filtering and/or settling process upstream of an NPDES discharge point; (C) pits constructed in association with heater treaters or other dehydration equipment used in production, such as free water knockouts, or first, second and third stage separators; (D) pits constructed for blowdown or gas flaring purposes., (iv) pits constructed for the storage and treatment of heavy sludges, oils, or basic sediment and water (BS&W) in connection with production operations; (v) temporary pits constructed during well workovers, including spent acid and frac fluid pits; (vi) permanent or temporary emergency use pits; (vii) miscellaneous pits associated with oil and gas production not listed above.
(Wyoming Rules Chapter 4 §1.b)

4. Oil and Gas Commission Pit Permits. No retaining pit or below-grade structure used for the containment of fluids, as defined in this section, shall be constructed unless Form 14A (Application for Permit to Construct and

Table 2.10 (continued)

Use Earthen Pit for Retention of Produced Water) or 14B (Application for Permit to Construct and Use Earthen Pit for Temporary Use, or Reserve Pit), has been submitted to and approved by the Supervisor and compliance with the Split Estates Act is demonstrated if applicable. (Wyoming Rules Chapter 4 §1.d)

5. Owners or operators of produced water retaining pits in operation prior to June 1, 1984, may continue to use such pits as long as the operation conforms to the current requirements of new pits, and shall be responsible for providing the information included on Form 14A upon request of the Supervisor. (Wyoming Rules Chapter 4 §1.e)

6. The Supervisor may administratively approve field-wide or area-wide applications covering the standardized construction and operation of earthen retaining pits. (Wyoming Rules Chapter 4 §1.f)

7. Centralized Pits. Owners or operators must obtain approval of the Supervisor for the location, construction and closure of noncommercial centralized pits located within a lease, unit, or communitized area used for field operations. Requirements may be more stringent than individual reserve or produced water pits depending on pit size, waste type, and location. Applicants shall provide additional notice, plats and plan views, and information relative to the location of water supplies, residences, schools, hospitals, or other structures where people are known to congregate, site security, groundwater monitoring and leak detection. These permits will be issued for a term of five (5) years and may be renewed at the discretion of the Supervisor. (Wyoming Rules Chapter 4 §1.h) Information on Emergency and Reserve Pits can be found in Wyoming Rules Chapter 4 §1.i-j.

8. Permits are valid for one (1) year from the date of issuance unless an extension has been approved for the Application for Permit to Drill (Form 1) and for as long as the permit conditions are met. Falsification of information on the application or filing of an incomplete application will result in automatic denial of the request. (Wyoming Rules Chapter 4 §1.k)

9. Workover and Completion Pits in Critical Areas. Approval of workover and completion pits proposed to be constructed in locations meeting the definition of pits in critical areas must be applied for and obtained on Form 14B prior to their construction and use by:
   a. (i) submitting Form 14B application for individual new (concurrent with (Form 1)) or existing wells;
   b. (ii) submitting Form 14B application for a field or unit wide permit, listing all wells meeting any of the above criteria.

   (Wyoming Rules Chapter 4 §1.l-m)

10. If the owner or operator complies with the approved Form 14B terms and conditions, no further approval to construct and use workover or completion pits will be required for those well sites. However, subsequent reporting, within thirty (30) days of completion of operations on Form 4 (Sundry Notice), is required each time a pit is constructed and used. Alternative reporting requirements such as annual reporting may be approved by the Supervisor. (Wyoming Rules Chapter 4 §1.n)

11. Workover and Completion Pits in Non-critical Areas. Workover and completion pits proposed to be constructed in locations not meeting any of the criteria listed in the definition of pits in critical areas, Chapter 1, Section 2(jj), will require either:
    a. (i) submittal of a Form 14B application for a field or individual well basis to receive a one-time approval to construct and use workover and completion pits. Compliance with the approved Form 14B terms and conditions will require no further application/notice for future construction and use of workover and completion pits.
    b. (ii) notification to the Supervisor via Sundry Notice (Form 4), subsequent to the construction and use of a workover or completion pit. This must be submitted within thirty (30) days of completion of operations and include the following information: (A) schematic diagram showing the location of the workover or completion pit in relation to existing production equipment; (B) length of time the pit was in use; and (C) statement addressing the types of fluids placed in the pit and that those fluids were removed prior to closure. (Wyoming Rules Chapter 4 §1.o)

Table 2.10 (continued)

12. General Information for Workover and Completion Pits. Upon review of Form 14B applications, the Commission staff will evaluate well locations to determine if their proposed siting is in a critical area (for distances from surface waters, depth to useable groundwater, soils, distances from human habitation, etc.). In the event construction is approved, special precautions or operational restrictions may be required by the Supervisor at these well facilities to avoid contamination of groundwater & surface water at the well location. Owners or operators should design workover or completion procedures so that additives will be expended while correcting the down-hole problems. (Wyoming Rules Chapter 4 §1.p-q)

13. Below Grade Structures (Tinhorns). For the purpose of its regulation, the Commission requires below grade structures (including tinhorns) used to receive oil, condensate, or produced water, to be applied for on Form 14A. Construction must be done in accordance with good engineering practice and the staff must be provided the opportunity to inspect prior to any use. A written monitoring program for all permitted below grade structures must be submitted and approved by the staff. (Wyoming Rules Chapter 4 §1.s)

14. Marking. The owner shall mark each pit in a conspicuous place with his name and the legal description of the location of the pit and shall preserve these markings. Exempted from this requirement are pits in close proximity to injection or producing wells marked in accordance with Chapter 3, Section 19. (Wyoming Rules Chapter 4 §1.t)

15. Location. When any retaining pit is located in an area with a high potential for communication between the pit contents and surface water or shallow ground water, or to provide additional protection to human beings when operations are conducted in close proximity to water supplies, residences, schools, hospitals, or other places where people are known to congregate, or to provide protection to livestock and wildlife, the Commission may require modifications or changes in the owner's plans as it deems necessary including, but not limited to, running a closed system, lining the pit, installing monitoring systems and providing additional reporting, or any other reasonable requirement that will insure the protection of fresh water. In areas where ground water is less than twenty feet (20') below the surface, a closed system must be utilized for well drilling operations. (Wyoming Rules Chapter 4 §1.u)

16. Operation. Owners or operators will take such reasonable measures to manage pits so that they are used solely for retention or disposal of fluids associated with the operation for which the pit was originally constructed and for which the permit was granted. Reserve pits cannot be used as production pits. Permits are granted taking into consideration the salinity, hydrocarbon content, pH, and other characteristics of the fluids which may be detrimental to the environment if they were to be directly applied to soils. Use of a pit by persons other than the owner or operator is prohibited unless approved by the Supervisor and by the owner or operator of the pit. Pits shall not receive, collect, store, or dispose of any wastes that are listed or defined as hazardous wastes and regulated under Subtitle C of RCRA, except in accordance with state and federal hazardous waste laws and regulations. The pit permit or approval is automatically canceled if these provisions are not met. (Wyoming Rules Chapter 4 §1.x)

17. For the purpose of its regulation of oilfield pits and wastes, the Commission recognizes, and requires when it deems appropriate, the following tests:
    a. (i) Standard Water Analysis - Form 17
    b. (ii) Toxicity Characteristic Leaching Procedures (TCLP), EPA Method 1311; July 1992.
    c. (iii) Oil and Grease or Total Petroleum Hydrocarbon (TPH), EPA Method 418.1; 1978.
    d. (iv) Total Petroleum Hydrocarbon, Condensate and High Gravity Crude, EPA, Method 8015, Gasoline and Diesel Range; July 1992.
    e. (v) United States Department of Agriculture, Sodium Absorption Ratio (SAR), Exchangeable Sodium Percentage (ESP); 1984.
    f. (vi) Wyoming Oil and Gas Commission Leachate Test Procedure; April 27, 1999.

    (Wyoming Rules Chapter 4 §1.ff)

18. Soil borings and testing must be performed by an independent engineering or geotechnical soil testing company or laboratory according to sound engineering practice in accordance with established industry standards. The logs of all borings, together with associated laboratory testing to classify soils and to measure soil strength, permeability, and other related parameters shall be submitted to the Supervisor. Sampling procedures are

subject to review by the Supervisor because variations in sampling protocol allow differentiation of waste fluid compositions due to normal distribution. (Wyoming Rules Chapter 4 §1.gg-hh)

B. Pit Removal & Reclamation

1. If the pit is proposed to be closed through the usual method of onsite natural evaporation and subsequent burial of solids, if pit treatment procedures are going to be applied, or if closure plans have changed from the original proposal approved on Form 14A or 14B, or any time wastes are disposed off-site, a Sundry Notice (Form 4) must be submitted and approved prior to closure. The Commission staff must be provided the opportunity to witness closure operations. Verbal notice at least twenty-four (24) hours prior to closure is required. Closure must be conducted in accordance with lease and landowner obligations and with local, state, and federal regulations:
   a. (i) Oil, water, and other fluids must be immediately removed from emergency pits and disposed in accordance with the Commission's rules. In the case of temporary emergency pits, evaporation or percolation of fluids prior to closure is not an acceptable disposal method. Permitted permanent emergency pits will not require immediate closure after use and fluid removal;
   b. (ii) Trenching or squeezing pits is expressly prohibited. Burial methods cannot compromise the integrity of manufactured, soil mixture, or recompacted clay liners without written approval by the Supervisor. One-time landspreading of reserve pit fluids on the drilling pad may be approved upon submittal of analyses, mud recaps and treating summaries, groundwater identification, and other information that is deemed appropriate. Prior approval must be obtained from the Supervisor if drilling fluid is disposed on the drill pad. A Sundry Notice (Form 4) with appropriate supporting detail must be submitted following the operation. Any offsite waste disposal is subject to DEQ regulations;
   c. (iii) Closure standards and testing requirements for all pits will be determined by the Supervisor based upon site-specific conditions;

   (Wyoming Rules Chapter 4 §1.ii)

2. All trash, paper, and unused structures or equipment must be removed from the location upon completion of operations. With landowner consent, operators may temporarily store equipment (such as drilling rigs) on a location while it awaits transfer. Reserve and produced water pits cannot be used for disposal of refuse, failed equipment parts, or unused chemicals. The inappropriate use of the pit for trash disposal may result in revocation of the permit. Further, operators are encouraged to choose chemical additives which are lower in toxicity or do not exhibit RCRA hazardous characteristics. (Wyoming Rules Chapter 4 §1.kk)

3. Landfarming and landspreading must be approved by the DEQ. Jurisdiction over roadspreading or road application is shared by DEQ and the Commission. The Commission is the agency responsible for permitting road applications of RCRA-exempt exploration and production wastes which include drilling fluids, produced water and produced water-contaminated soils, waste crude oil, sludges, and oil-contaminated soils inside the boundaries of a lease, unit, or communitized area. The roadspreading application shall include acceptable evidence of landowner consent and the information included on the Commission's Form 20. Landfarming, landspreading, and roadspreading shall be protective of human health and the environment and shall be performed in compliance with all other applicable State and Federal regulations and requirements. (Wyoming Rules Chapter 4 §1.mm)

4. The Commission may require testing of wastes and additional disposal requirements prior to closure of a pit if they have reason to believe exempt exploration and production wastes have been commingled with hazardous wastes, upon analysis of an operator's mud program, or in previously identified sensitive environments. (Wyoming Rules Chapter 4 §1.nn)

5. Any person, corporation, or company desiring to chemically and/or mechanically treat pits in Wyoming must apply for and receive permission to do so from the Commission after a public hearing. Types of approved treatments include enhanced evaporation, solidification, centrifuging, etc. The Commission will approve those methods that can successfully demonstrate a capability to accomplish some or all of the following criteria: (i) compressive strengths that are appropriate for post drilling or production activities; (ii) reductions in weight or volume of waste; (iii) removal or reduction of harmful properties of waste; and (iv) reduction or elimination of mobility or leachability of constituents. (Wyoming Rules Chapter 4 §1.oo)

Table 2.10 (continued)

6. An operator or owner wishing to treat pits for closure must submit, to the Commission on a Sundry Notice (Form 4), a plan outlining the objectives (e.g. waste volume reduction, toxicity reduction/removal, chemical fixation, etc.) that the treatment is designed to achieve. The Commission's approval will be based upon the selected method's demonstrated capability to achieve the objectives described in the sundry notice. Consideration must be given to applicable federal, local, or state permits or regulatory requirements when performing mechanical or chemical treatment of pit wastes. A list of approved methods and vendors is available from the Commission. (Wyoming Rules Chapter 4 §1.pp)

7. Reclamation. Reclamation of unused production pits or any other temporary retaining pits, including reserve pits, shall be completed in as timely a manner as climatic conditions allow. Production pit areas and reserve pits will be reclaimed no later than one (1) year after the date of last use unless the Supervisor grants an administrative variance for just cause. Because their construction may be a benefit to landowners, pits used solely for the retention of water produced in association with the recovery of coalbed methane gas in the Powder River Basin may be left open with the approval of the Supervisor and subject to Chapter 3, Section 4(h)(ii). A statement of acceptance which clearly indicates the surveyed location, precise size of the pit, and willingness on the part of the landowner to accept all future responsibility for the structure and its contents, accompanied by a current written cost estimate for pit closure prepared by a Wyoming registered professional engineer with expertise in surface pit remediation, must be provided to and accepted by the Supervisor. The landowner's signature on the statement of acceptance must be notarized. (Wyoming Rules Chapter 4 §1.qq)

8. (rr) Site rehabilitation should be in accordance with reasonable landowner's wishes, and/or resemble the original vegetation and contour of the adjoining lands. Where practical, topsoil must be stockpiled during construction for use in rehabilitation. All disturbed areas on state lands will be reseeded. The owner or operator shall advise the Supervisor of the completion of reclamation of a production or reserve pit by submitting a Sundry Notice (Form 4). (Wyoming Rules Chapter 4 §1.rr)

9. Workover and completion pits shall be open only for the duration of operations and must be closed within thirty (30) days after the operation is complete. (Wyoming Rules Chapter 4 §1.q)

C. Freeboard Requirement

1. Liquids must be kept at a level that takes into account extreme precipitation events and prevents overtopping and unpermitted discharges. (Wyoming Rules Chapter 4 §1.w.viii)

D. Liner Requirement

1. Construction. Lining of pits with reinforced oilfield grade material, compatible with the waste to be received, will be required by the Supervisor or Commission under certain circumstances. Pits constructed in fill or those used to retain oil base drilling muds, high-density brines, and/or completion or treating fluids must be lined. Pits constructed to retain produced water with a total dissolved solids concentration in excess of 10,000 milligrams per liter must be lined. The Supervisor, on a case by case basis, will determine if pits retaining water with a total dissolved solids concentration less than 10,000 milligrams per liter will be required to be lined. The Commission staff must be provided at least twenty-four (24) hours notice of commencement of construction and/or of closure of pits so that an inspection can be made. Additionally, the following construction standards for pits are required to be met or exceeded:
    a. (i) Soil mixture liners, recompacted clay liners, and manufactured liners must be compatible with the waste contained. On request of the Supervisor, the operator must provide evidence of the chemical resistance of the liner selected for use.
    b. (ii) Liners constructed of synthetic materials must meet the following specifications: a 9 to 12 mil thickness, greater than 20% elongation at failure, puncture strength of 60 pounds, tear strength of 50 pounds, and permeability less than 10-7 cm/sec. Joints must be overlapped a minimum of 2 inches and seams sealed as recommended by the manufacturer. Blemishes, holes, or scars must be repaired per manufacturer's recommendation. Breaches in the liner for siphons or other equipment must be reinforced.
    c. (iii) Slopes for soil mixture liners or recompacted liners shall not exceed 3:1. Slopes for manufactured liners shall not exceed 1:1.

   d. (iv) Reasonable provisions for protection of liners during filling and emptying activities must be included in the construction plans.
   e. (v) Manufactured liners must be installed over smooth fill subgrade which is free of pockets, loose rocks, or other materials which could damage the liner. Sand, sifted dirt or bentonite are suggested. At no time will straw or any other organic material except synthetic cushion fabric designed for that purpose be used for a liner cushion. Installation of synthetic or soil mixture liners must be in accordance with accepted engineering practice.
   f. (vi) Liner edges must be secured. The Commission prefers that liner edges be placed in a trench which is deep enough to receive approximately one foot (1') of compacted soil which will anchor the material.
   g. (vii) Monitoring systems may be required for pits constructed in sensitive areas. Such pits must be operated in a manner that avoids damage to liner integrity. Periodic inspections, weekly at a minimum, of pits must be made by the owner or operator and documentation of such inspections may be required to be submitted to the Supervisor at his request.

   (Wyoming Rules Chapter 4 §1.w)

2. The Commission specifically prohibits the use of dispersants, wetting agents, surface reduction agents, surfactants, or other chemicals that destroy, remove, or reduce the fluid seal of a reserve pit and allow the fluids contained therein to seep, drain, or percolate into the soil underlying the pit. (Wyoming Rules Chapter 4 §1.ll)

3. Unlined pits shall not be constructed in fill. Pits of any kind shall not be constructed in drainages, or in the floodplain of a flowing or intermittent stream, or in an area where there is standing water during any portion of the year. (Wyoming Rules Chapter 4 §1.v)

E. Spill Requirements

1. Uncontained spills or unauthorized releases of produced fluids, drilling muds, produced water, hydrocarbons, or chemicals which enter, or threaten to enter, waters of the state must be verbally reported to the Commission no later than the next business day following discovery of the incident. Spills of less than ten (10) barrels (420 gallons) of crude oil, petroleum condensate, produced water, or a combination thereof which occur on a lease, unit, or communitized area and do not physically enter waters of the state and are immediately contained, removed, and disposed of properly are not required to be reported. The owner or operator shall file a written report within fifteen (15) working days.

2. A hazardous substance release in any amount which enters, or threatens to enter, waters of the state shall be reported, contained, removed, and disposed of in accordance with these regulations.
   a. Any person owning or having control over oil or a hazardous substance which, after release, enters, or threatens to enter, waters of the state shall:
      i. immediately take appropriate action to stop and contain the release.
      ii. Immediately notify the division of the type, quantity, and location of the release, and of the response, containment, and cleanup actions which have been taken or are proposed to be taken.
         (i) (A) The following releases are not required to be reported to the division provided the release does not physically enter waters of the state, and it is immediately contained, removed, and disposed of in accordance with departmental regulations:
            1. (I) Ten barrels (420 gallons) or less of crude oil, petroleum condensate, produced water, or a combination thereof;
            2. (II) Twenty-five (25) gallons or less of refined crude oil products, including but not limited to, gasoline, diesel motor fuel, aviation fuel, asphalt, road oil, kerosene, fuel oil, and derivatives of mineral, animal, or vegetable oils.
      iii. Immediately proceed to correct the cause of the release.
      iv. Within seven (7) days following a release, submit a complete written report to the division describing the reportable release and steps taken to prevent a recurrence.
   b. (b) Cleanup of oil or hazardous substance releases shall proceed in a timely and diligent manner. Satisfactory

   (Wyoming Water Quality Rules and Regulations - Ch. 4, §4)

F. Disposal & Recycling of Liquid & Solid Fractions

Table 2.10 (continued)

1. The owner or operator shall not pollute streams, underground water, or unreasonably damage or occupy the surface of the leased premises or other lands. No fluid contents of any pit will be discharged or allowed to escape to the surface without prior approval through issuance of an NPDES permit by DEQ and other required authorization. No drilling fluids will be discharged into live waters or into any drainage that lead to live waters of the state. If liquid products of wells cannot be treated or destroyed, or if the volume of such products is too great for disposal by the usual method of onsite natural evaporation and burial of solids, the Supervisor must be consulted and the liquids disposed of by an approved method. (Wyoming Rules Chapter 4 §1.ee)

2. Trash and sanitary waste should not be retained in or disposed of in pits on location or downhole. (Wyoming Rules Chapter 4 §1.aa)

3. Blowdown, flare, and emergency pits cannot be used for long-term storage or disposal. (Wyoming Rules Chapter 4 §1.cc)

4. All retaining pits shall be kept reasonably free of surface accumulations of oil and other liquid hydrocarbon substances and shall be cleaned within ten (10) days after discovery of the accumulation by the owner or notice from the Supervisor. (Wyoming Rules Chapter 4 §1.dd)

5. Unused commercial products shall not be disposed with exempt oilfield wastes. The commingling of any listed hazardous waste with the otherwise exempt pit contents may render the entire mixture a hazardous waste and results in closing the pit under the RCRA hazardous waste regulations. All reasonable efforts should be made to completely use commercial products. Products should be returned to the vendor if appropriate, or segregated from other wastes for management or disposal. Oil base muds must be segregated from water base drilling fluids because pit closure is complicated by their presence. Mixing and treating of oil based and water-based muds can be allowed with approval of the Supervisor. Rigwash may be routed to the reserve pit provided care is taken to avoid contamination of the pit contents by rig oil and other nonexempt wastes. (Wyoming Rules Chapter 4 §1.y)

6. Where feasible, operators are encouraged to increase the use of solids removal equipment to minimize drilling fluid waste. The Commission encourages the recycling of drilling fluids and by administrative action approves the transfer of fluids. When removed as a product for use in a drilling operation on another lease, drilling fluid is not classified as a waste. If federal leases are involved, the owner or operator must obtain the approval of the BLM. The Supervisor requires the following information be included on the Form 14B or on a Sundry Notice (Form 4) estimated volume, estimated date of transfer, mud recap, analyses which include at a minimum, pH, chlorides, and oil and grease. To protect shallow groundwater, drilling muds with chlorides testing in excess of 3,000 parts per million or those containing hydrocarbons cannot be used in drilling operations until after the surface casing has been set. (Wyoming Rules Chapter 4 §1.z)

7. Pit solids showing high concentrations of salt (ESP > 15) must be removed from the location and disposed in a permitted facility, encapsulated, or chemically or mechanically treated; (Wyoming Rules Chapter 4 §1.ii.iv)

8. Oil based mud solids must be removed and disposed in a permitted facility, or mixed with soil to less than one percent (1%) oil and grease content by weight at burial, solidified using a Commission approved commercial pit treatment or roadspread or landspread or landfarmed in accordance with Commission or DEQ rules. Burial after encapsulation or solidification will be approved if the stabilized mixture contains less than 10 milligrams per liter (10 mg/l) leachable oil. (Wyoming Rules Chapter 4 §1.ii.v)

9. An application for approval of reserve pit fluid injection shall demonstrate that water in the proposed disposal interval is in excess of 10,000 milligrams per liter total dissolved solids or has received an aquifer exemption under Chapter 4, Section 12 and that fresh water or Underground Sources of Drinking Waters (USDW) will not be influenced by the disposal operation. Data to support this finding shall include, but not be limited to, the following:
   a. (i) full detail of the casing, cementing, and completion of the well including cement logs; (ii) formation tops and depths to the deepest USDW; (iii) copies of the mud recaps, appropriate analyses of the fluid, and an estimate of the volume of the fluids to be disposed; (iv) abandonment procedure and demonstration that

the disposal zone can be isolated; (v) maximum disposal pressure anticipated and information relative to fracture pressures of the confining zone. Pump pressure must be limited so that fractures will not extend to the base of a USDW and/or a groundwater aquifer; (vi) the statement that the owner or operator will make arrangements to provide at least twenty-four (24) hours notice of disposal operation so that a Commission technician might be present as a witness; and (vii) statement that on completion of the work a temperature survey or suitable alternative will be run to show fluid was placed in the proposed interval.

The Commission or its staff may designate conditions other than those listed in this rule, as it deems necessary to ensure safe disposal of these fluids.
(Wyoming Rules Chapter 4 §1.tt, & .vv)

10. On completion of the work, the applicant must file a Sundry Notice (Form 4), summarizing the disposal operation. (Wyoming Rules Chapter 4 §1.uu)

G. Tank Use

1. Maintain tanks in a workmanlike manner which will preclude seepage from their confines and provide for all applicable safety measures. Owners or operators should be aware of their responsibility to comply with spill prevention control and countermeasures plan (SPCC 40 CFR 112) requirements that regulate the prevention and containment of crude oil spills. SPCC regulations and guidelines specify that applicable facilities construct appropriate containment or diversionary structures or equipment to prevent discharged oil from reaching waters of the United States. The use of crude oil tanks without tops is strictly prohibited;

2. Workover pits should retain only RCRA exempt wastes. Other wastes should be managed in tanks for later recycling, reuse, or proper disposal. (Wyoming Rules Chapter 4 §1.q)

H. Pit Protection

1. Reserve and Produced water pits shall be completely fenced and, if oil or other harmful substances are present, netted or otherwise secured at the time the rig substructure has been moved from the location in a manner that avoids the loss of wildlife, domestic animals, or migratory birds. The Commission recommends netting for the securing of pits. Owners or operators shall provide for devices on hydrogen sulfide flare stacks to discourage birds from perching. The Supervisor may request security when in close proximity to residences, schools, hospitals, or other structures or locations where people are known to congregate. (Wyoming Rules Chapter 4 §1.bb)

2. Water Well Testing Requirements-None found, yet.

3. Fracturing Fluid Requirements and Fluid Use and Recycling

A. Fluid Use

1. The right to divert or store water for oil or gas drilling can be acquired by complying with the provisions of §41-10.1 and 10.2, Wyoming Statutes 1957. (Wyoming State Engineer-Document #1795, Chapter 4 §1)

2. Water User must fill out a Water Agreement for Temporary Use of Water Form. The application must include a map with the point of diversion from a stream clearly outlined within a proper legal subdivision; the amount to be removed along with the maximum rate of diversion. If tanker trucks are used to haul water, the capacity of the pump loading the truck may be used; the date of initial diversion and the period of time that water will be diverted. (Wyoming State Engineer-Document #1795, Chapter 4 §2)

3. The maximum time allowed for temporary use may not exceed a 2-year period. (Wyoming State Engineer-Document #1795, Chapter 4 §3)

Table 2.10 (continued)

B. Numeric water quality standards shall be enforced at all times except during periods below low flow. Low flow can be determined by the following methods. Whatever method is selected for a specific situation, application of the standards will conform to the magnitude, frequency, and duration provisions as described in these regulations.
   1. (i) Using the 7Q10 (the minimum seven (7) consecutive day flow which has the probability of occurring once in ten (10) years);
   2. (ii) The EPA's biologically based flow method which determines a four (4) day, three (3) year low flow for chronic exposures and a one (1) day, three (3) year low flow for acute exposures (ref: Technical Guidance Manual For Performing Waste Load Allocation; Book VI, Design Conditions: Chapter 1, Stream Design Flow for Steady-State Modeling, August 1986, US EPA); (iii) Other defensible scientific methods.

   (Wyoming Water Quality Rules and Regulations, Chapter 1 §11)

C. During periods when stream flows are less than the minimums described above, the department may, in consultation with the Wyoming Game and Fish Department and the affected discharger(s), require permittees to institute operational modifications as necessary to insure the protection of aquatic life. This section should not be interpreted as requiring the maintenance of any particular stream flow. (Wyoming Water Quality Rules and Regulations, Chapter 1 §11)

D. In all Wyoming surface waters, substances attributable to or influenced by the activities of man shall not be present in amounts which would cause: (a) The oil and grease content to exceed 10 mg/L; or (b) The formation of a visible sheen or visible deposits on the bottom or shoreline, or damage or impairment of the normal growth, function or reproduction of human, animal, plant or aquatic life. (Wyoming Water Quality Rules and Regulations, Chapter 1 §29)

E. In all Wyoming surface waters, substances attributable to or influenced by the activities of man that will settle to form sludge, bank or bottom deposits shall not be present in quantities which could result in significant aesthetic degradation, significant degradation of habitat for aquatic life or adversely affect public water supplies, agricultural or industrial water use, plant life or wildlife. Floating and suspended solids attributable to or influenced by the activities of man shall not be present in quantities which could result in significant aesthetic degradation, significant degradation of habitat for aquatic life, or adversely affect public water supplies, agricultural or industrial water use, plant life or wildlife. (Wyoming Water Quality Rules and Regulations, Chapter 1 §15-16)

F. A discharge or activity that impacts an underground source of water for existing uses identified in W.S. 35-11-102 and 103(c) (i) shall not make the affected water unsuitable for its intended use or uses, at any place or places of withdrawal or natural flow to the surface. (Wyoming Water Quality Rules and Regulations, Chapter 8 §4.c)

G. All Wyoming surface waters which have the natural water quality potential for use as an industrial water supply shall be maintained at a quality which allows continued use of such waters for industrial purposes. Degradation of such waters shall not be of such an extent to cause a measurable increase in raw water treatment costs to the industrial user(s). Unless otherwise demonstrated, all Wyoming surface waters have the natural water quality potential for use as an industrial water supply (Class 4 Waters). (Wyoming Water Quality Rules and Regulations, Chapter 1 §19)

H. Specific numeric standards for a number of toxicants are listed in the aquatic life "acute value" and "chronic value" columns in Appendix B of these regulations. These standards apply to all Class 1, 2A, 2B, 2AB, 2C, 3A, 3B and 3C waters. For these pollutants, the chronic value (four (4) day average concentration) and the acute value (one (1) hour average concentration) shall not be exceeded more than once every three (3) years. For those pollutants not listed in Appendix B or C of these regulations, maximum allowable concentrations on Class 1, 2 and 3 waters shall be determined through the bioassay procedures outlined in the references listed in Appendix E of these regulations. (Wyoming Water Quality Rules and Regulations, Chapter 1 §21 b-c)

I. In all Class 2A, 2D and 3 waters, wastes attributable to or influenced by the activities of man shall not deplete dissolved oxygen amounts to a level which will result in harmful acute or chronic effects to aquatic life, or which would not fully support existing and designated uses. In all Class 1, 2AB, 2B and 2C waters, wastes attributable to or influenced by the activities of man shall not be present in amounts which will result in a dissolved oxygen content of less than that presented on the chart in Appendix D of these regulations. (Wyoming Water Quality Rules and Regulations, Chapter 1 §24)

J. For all Wyoming surface waters, wastes attributable to or influenced by the activities of man shall not be present in amounts which will cause the pH to be less than 6.5 or greater than 9.0 standard units. For all Class 1, 2 and 3 waters, effluent attributable or influenced by human activities shall not be discharged in amounts which change the pH to levels which result in harmful acute or chronic effects to aquatic life, directly or in conjunction with other chemical constituents, or which would not fully support existing and designated uses. (Wyoming Water Quality Rules and Regulations, Chapter 1 §26)

K. Point source discharges to the surface waters in the Colorado River Basin of Wyoming shall be controlled as described in Policy For Implementation of the Colorado River Basin Salinity Standards through the NPDES Permit Program. In general, the policy shall be no discharge of salt except where it is not economically or technologically practicable to prevent the discharge. (Wyoming Water Quality Rules and Regulations, Chapter 6 §4)

4. Hydraulic Fracturing Operation Requirements

A. Permitting

1. Before any persons shall spud in and begin the drilling of any well on fee, patented, state, or federal lands, or deepen any such wells by drilling to a lower formation, such persons shall file an Application for Permit to Drill or Deepen (Form 1) with the Commission and pay a fee of fifty dollars ($50.00) for a permit effective May 1, 1996. No drilling activity shall commence until such application is approved and a permit to drill is issued by the Commission. (Wyoming Rules Chapter 3 §8.a).

2. (b) For wells drilled on fee, patented and state land, prior to construction of the drilling location, approval of Form 14B (Application to Construct a Reserve Pit) must be obtained. The Application for Permit to Drill will not be processed until this requirement is met. (Wyoming Rules Chapter 3 §8.b)

3. (c) The Application for Permit to Drill or Deepen (Form 1) shall be accompanied by an accurate plat showing the location of the proposed well with reference to the nearest lines of an established public survey. Information to be included in such notice shall be the type of tools to be used, proposed depth to which the well will be drilled, estimated depth to the top of the important markers, estimated depth to the top of objective horizons, the proposed casing program, including size and weight thereof, the depth at which each casing string is to be set, and the amount of cement to be used. Information shall also be given relative to the drilling plan, together with any other information which may be required by the Supervisor. Where multiple Applications for Permit to Drill will be sought for several wells proposed to be drilled to the same zone within an area of geologic similarity, approval may be sought from the Supervisor to file a comprehensive drilling plan containing the information required above which will then be referenced on each Application for Permit to Drill. (Wyoming Rules Chapter 3 §8.c)

4. (d) The Application for Permit to Drill or Deepen (Form 1) shall also be accompanied by a statement of compliance with WYO. STAT. ANN. § 30-5-403 (Form 1A), if the application is not exempted from the Split Estates Act. Included in this statement shall be the surface owner's name, contact address, telephone number and any other relevant and necessary contact information. The statement shall certify that the oil and gas operator has done the following:
   a. (i) provided notice of proposed oil and gas operations to the surface owner;
   b. (ii) engaged in good faith negotiations to reach a surface use agreement with the surface owner, and
   c. (iii) satisfied the conditions of WYO. STAT. ANN. § 30-5-402(c) and how they were satisfied. The oil and gas operator shall not file a copy of any surface use agreement, nor will the terms of any such agreement be disclosed.

   (Wyoming Rules Chapter 3 §8.d)

5. (e) Each Application for Permit to Drill or Deepen (Form 1) shall be accompanied by a sworn statement from the operator, on a form approved by the Commission, that all underground electrical conductors outside of its

Table 2.10 (continued)

facilities, fenced enclosures, or posted areas will comply with the 2005 Electrical Code as adopted by the Department of Fire Prevention and Electrical Safety. Operator shall provide WOGCC at least twenty-four (24) hours notice prior to installation of underground electrical conductors outside of its facilities, fenced enclosures, or posted areas. With routine maintenance, emergency or repair work, the Operator shall provide the WOGCC notice within twenty-four (24) hours of completing the electrical work. (Wyoming Rules Chapter 3 §8.e)

6. (f) In addition to any other required form or attachment to the Application for Permit to Drill, the following shall be submitted:
   a. (i) For directional wells a diagram clearly showing the proposed direction of the deviation and the proposed horizontal distance between the bottom of the hole and the surface location;
   b. (ii) For horizontal wells a diagram shall be submitted clearly showing the wellbore path from the surface through the terminus of the lateral. A horizontal well's number shall be appended with an "H" suffix, denoting horizontal, in Block 8 of Form 1. If more than one lateral borehole extends from the same vertical wellbore, each such lateral must be permitted as an individual horizontal well with an "H" suffix. The surface location and the proposed footage locations of both the initial penetration into the productive formation and the terminus of the lateral shall be entered under "Location". If the application is for a permit to drill a horizontal well, notice of the application shall be given by certified mail to all owners within one-half (½) mile of any point on the entire length of the horizontal wellbore, from the surface location through the terminus of the lateral. In the absence of any special Commission order, notice is not required for horizontal wells in federally supervised units or in API units provided that no portion of the horizontal interval is closer than six hundred-sixty feet (660') from a drilling or spacing unit boundary or any uncommitted tract.

   (Wyoming Rules Chapter 3 §8.f)

7. (g) After receipt by the Commission at the office of the Supervisor of a proper application from an interested party requesting the establishment of drilling units or the revision of existing drilling units for the spacing of wells within a certain designated area, or upon a decision by the Supervisor or the Commission to call a hearing for the establishment of drilling units or the revision of existing drilling units within a certain designated area, any Application for Permit to Drill within any such designated area will be held in abeyance by the Commission until such time as the matter has been fully heard and determined; except, however, a permit shall be issued by the Supervisor if an owner files a sworn application and demonstrates therein to the Supervisor's satisfaction that on the date the application requesting such drilling units was filed:
   a. (i) he has the right or obligation under the terms of an existing contract to drill said well; and
   b. (ii) he has a leasehold estate or right to acquire a leasehold estate under said contract which will be terminated unless he is permitted to commence the drilling of said well before the matter of spacing can be fully heard and determined by the Commission.

   (Wyoming Rules Chapter 3 §8.g)

8. (h) If drilling is not commenced, the permit to drill shall not be valid after the expiration of a period of one (1) year from the date of the issuance thereof by the Commission or its authorized agents. A new application shall be submitted prior to the expiration date of the Permit to Drill, along with a $50.00 extension fee, in order to request a one (1) year extension from such expiration date. (Wyoming Rules Chapter 3 §8.h)

9. (i) All plats shall contain the following information:
   a. (i) section, township, range and county that the well is to be located within; (ii) north arrow; (iii) scale of drawing. This should include a bar graph and a ratio showing the scale of the map; (iv) a description of all monuments found, set, reset or replaced and notation of all distances measured between the corners used in establishing the section boundary in which the well is located; (v) distances from the nearest established section boundary lines to the proposed well; (vi) ungraded ground elevation of the well; (vii) basis of elevations; (viii) basis of bearings; (ix) signed Wyoming Registered Land Surveyor Certificate or statement indicating that the well was actually staked by the surveyor or others under his direct supervision as exhibited on the plat.

   (Wyoming Rules Chapter 3 §8.i)

Table 2.10 (continued)

10. (j) Latitude and longitude in degrees, with five (5) decimal places and the datum used, if not contained on the plat, is to be furnished within thirty (30) days of the completion of the well. Latitude and longitude values shall be accurate to within one hundred fifty feet (150'). (Wyoming Rules Chapter 3 §8.j)

11. (k) Within the Special Sodium Drilling Area –A or –B (SSDA –A or –B) as defined in Chapter 1, Section 2 (qq) or (rr), a notice of the Application for Permit to Drill shall be given by certified mail to all trona producers holding current valid DEQ permits to mine trona. (Wyoming Rules Chapter 3 §8.k)

B. Notifications

1. Upon completion or recompletion of a well, stratigraphic test or core hole, or the completion of any remedial work such as plugging back or drilling deeper, acidizing, shooting, formation fracturing, squeezing operations, setting a liner, gun perforating, or other similar operations not specifically covered herein, a report on the operation shall be filed with the Supervisor. Such report shall present a detailed account of the work done and the manner in which such work was performed; the daily production of oil, gas, and water both prior to and after the operation; the size and depth of perforations; the quantity of sand, crude, chemical, or other materials employed in the operation and any other pertinent information of operations which affect the original status of the well and are not specifically covered herein. (Wyoming Rules Chapter 3 §12)

C. Drilling

1. A written notice of intention to do work or to change plans previously approved on the original APD and/or drilling and completion plan (Chapter 3, Section 8(c)) must be filed with the Supervisor on the Sundry Notice (Form 4), unless otherwise directed, and must reach the Supervisor and receive his approval before the work is begun. Approval must be sought to acidize, cleanout, flush, fracture, or stimulate a well. The sundry notice must include depth to perforations or the openhole interval, the source of water and/or trade name of fluids, type of proppants, as well as estimated pump pressures. Routine activities that do not affect the integrity of the wellbore or the reservoir, such as pump replacements, do not require a sundry notice. The Supervisor may require additional information. (Wyoming Rules Chapter 3 §1.a)

2. Within thirty (30) days after logs are run on any well or within thirty (30) days after the completion of any further operation on it, if such operations involve drilling deeper or redrilling any formation, the owner shall submit to the Supervisor two (2) copies of the well log on the form prescribed by the Commission as well as two (2) copies of the electrical, radioactive, or other similar conventional logs run. If requested by the owner, the Supervisor may grant an extension to the thirty (30) day reporting period for any well. The Commission would appreciate receiving logs, if available, in digital form or disc in addition to those mentioned above. The format shall be LAS, Log ASCII standard or any other format approved by the Supervisor. (Wyoming Rules Chapter 3 §21.a)

3. Unless otherwise ordered by the Commission upon hearing, all wells shall be so drilled that the horizontal distance between the bottom of the hole and the location at the top of the hole shall be at all times a practical minimum. Horizontal wells are exempt from this rule. (Wyoming Rules Chapter 3 §24)

4. Surface casing shall be run to reach a depth below all known or reasonably estimated utilizable domestic fresh water levels and to prevent blowouts or uncontrolled flows. Fresh water flows detected during drilling including seismic, core, or other exploratory holes shall be recorded on Form 19 (Report of Fresh Water Flows) and reported to the Commission on the next business day. Information contained on the form shall describe the depth at which the sand was encountered, the thickness, and the rate of water flow, if known. In areas where pressures and formations are unknown, surface casing shall be of sufficient size to permit the use of an intermediate string or strings of casing. Surface casing shall be set in or through an impervious formation and shall be cemented by the pump and plug or displacement or other approved method with sufficient cement to fill the annulus to the top of the hole, all in accordance with reasonable requirements of the Supervisor. If cement is not circulated to the surface during the primary operation, the operator shall perform supplemental cementing operations to assure that the annular space from the casing shoe to the surface is filled with cement; (Wyoming Rules Chapter 3 §22.a.i)

5. Horizontal & Directional Wells (Wyoming Rules Chapter 3 §25)
   a. Before beginning controlled directional drilling, other than whipstocking because of hole conditions, when the intent is to direct the bottom of the hole away from the vertical, notice of intention to do so shall be filed with the Supervisor and his approval obtained. The approval will be valid for one year from the date it was granted. Such notice shall state clearly: (i) the depth; (ii) exact surface location of the wellbore; (iii) proposed direction of deviation; and (iv) proposed horizontal distance between the bottom of the hole and surface location.
   b. (b) If approval is obtained, the owner shall file with the Supervisor within thirty (30) days after the completion of the work an accurate and complete copy of the survey made.
   c. (c) Additional notice to directional drill shall not be required if the proposed bottomhole location will be drilled to an authorized location pursuant to Section 2 of this chapter, a drilling and spacing order, or any other special order of the Commission.
   d. (d) This rule also applies to horizontal wells, and the horizontal well diagram submitted with the Application for Permit to Drill shall serve as the above-required notice to the Supervisor.

D. Stimulation

1. Within the Special Sodium Drilling Area – A or – B as defined in Chapter 1, Section 2(qq) or (rr) or all wells defined in Chapter 1, Section 2 unless altered, modified, or changed upon hearing before the Commission, or shown to contain no Trona Mineral Resources, shall only use stimulation methods that do not significantly damage the Trona Mineral Resources. A plan of work for any stimulation operation shall be submitted to the Supervisor and approved before the work is undertaken.
   a. (i) Well stimulation operations within the Trona Interval shall include a post stimulation survey that identifies the extent of induced fractures. Results of the survey shall be submitted to the Supervisor for evaluation to determine if induced fractures have significantly intersected the Trona Mineral Resources and if corrective action is required.
   b. (ii) Stimulation fluids shall be designed to prevent significant dissolution to the Trona Mineral Resources. The Supervisor shall require corrective action if it is determined that significant damage to the Trona Mineral Resources has, or is likely to occur.

   (Wyoming Rules Chapter 3 §22.f)

E. Surface Rehabilitation

1. Site reclamation must be initiated within one (1) year of permanent abandonment of a well or last use of a pit and shall be completed in as timely a manner as climatic conditions allow. For just cause, the Supervisor may grant an administrative variance providing for additional time. Reclamation must be completed in accordance with the landowner's reasonable requests, and/or resemble the original vegetation and contour of adjoining lands. Where practical, topsoil must be stockpiled during construction for use in reclamation. All disturbed areas on state lands will be recontoured and reseeded unless the Office of State Lands and Investments approves otherwise. (Wyoming Rules Chapter 3 §17.b)

2. When rehabilitation of the surface is complete and the well is ready for inspection and bond release, the operator or owner shall so advise the Supervisor by submitting a Sundry Notice (Form 4) marking the area on the form advising such. Inspections for the purpose of bond release will not be made by the Commission staff until that request is provided by the operator or owner. The SRA will be approved only after the site has been inspected and recommended for bond release by a Commission staff member. (Wyoming Rules Chapter 3 §17.c)

5. Noise and Light Impact Minimization and Mitigation-None found, yet.

6. Setbacks

A. Human Health & Safety

1. Pits, wellheads, pumping units, tanks, and treaters shall be located no closer than three hundred fifty feet (350') from to water supplies, residences, schools, hospitals, or other structures where people are known to congregate. The Supervisor may impose greater distances for good cause and likewise grant exceptions to the 350-foot rule. (Wyoming Rules Chapter 3 §22.b)

7. Multiple Well Pad Reclamation Practices-None Found, yet.

8. NORM

9. Storm Water Runoff

A. The department may issue a general permit to cover a category of discharges, except those covered by individual permits, within a geographic area which shall correspond to existing geographic or political boundaries. The general permit may be written to regulate:
   1. (i) Storm water point sources except;
      a. (A) Storm water discharges associated with industrial activities (as defined in Section 6 (g) (ii) (A) through (K)) that have a potential to reach surface waters of the state that are listed as being Class 1 in Appendix A of Chapter 1, Wyoming Water Quality Rules and Regulations. These facilities must apply for an individual storm water permit in accordance with the requirements of Section 6 (b).
      b. (B) Storm water discharges from large or small construction activity as defined in Section 6 (f) are not included in the exception of Section 4 (a) (i) (A).

(Wyoming Water Quality Rules and Regulations, Chapter 2 §4.a)

B. Authorization to discharge.
   1. (i) Except as otherwise provided in these regulations, any person seeking coverage under a general permit shall submit to the department a complete notice of intent, supplied by the administrator, to be covered by the general permit. Any person who fails to submit a notice of intent in accordance with the terms of the general permit is not authorized to discharge under the terms of the permit unless the general permit, in accordance with Section 4 (b) (v), contains a provision that a notice of intent is not required.

   2. (ii) The minimum requirements of the notice of intent shall be specified in the general permit and shall require the submission of information necessary for adequate program implementation. All notices of intent shall be signed as described in Section 14 of these regulations.

   3. (iii) General permits shall specify the deadlines for submitting notices of intent and the date(s) when a discharge is authorized under the permit unless otherwise specified in the authorization. (A) In any event, no person shall commence a discharge without having obtained written authorization from the department, and no authorization shall be issued without full compliance by the permittee with all requirements of these regulations. (B) In any event, no person shall change or alter the conditions of an authorized discharge without having obtained an authorization from the department and no authorization for the modification shall be issued without full compliance by the permittee with all requirements of these regulations. (C) In any event, no person shall continue to discharge beyond the expiration date of an authorization without having obtained an extension or renewal of the authorization from the department, and no extension or renewal shall be granted without full compliance by the permittee with all requirements of these regulations.

   4. (iv) General permits shall specify eligibility requirements for coverage under the permit and procedures for submitting notices of intent and granting authorization.

   5. (vi) The administrator may notify a discharger that it is subject to the conditions and requirements of a general permit, even if the discharger has not submitted a notice of intent to be covered.

   (Wyoming Water Quality Rules and Regulations, Chapter 2 §4.b)

C. Water quality-based limits. Where sources within a specific category or subcategory of dischargers are subject to water quality-based limits imposed pursuant to Section 5 of these regulations, the source in that specific category or

Table 2.10 (continued)

subcategory shall be subject to the same water quality-based effluent limitations, when applicable. (Wyoming Water Quality Rules and Regulations, Chapter 2 §4.c)

D. Discharge Allowances

1. For any storm water discharge associated with large or small construction activities or industrial activities from a facility that is owned or operated by a municipality with a population of less than 100,000 that is not authorized by a general or individual permit, other than an airport, power plant, or sanitary landfill, a permit application must be submitted to the administrator by March 10, 2003. (Wyoming Water Quality Rules and Regulations, Chapter 2 §6.a.ii)

2. Storm water discharges associated with small construction activity at oil and gas exploration, production, processing, and treatment operations or transmission facilities, require permit authorization as of March 10, 2005. (Wyoming Water Quality Rules and Regulations, Chapter 2 §6.a.iv)

3. A permit application shall be submitted to the administrator within 60 days of notice of a storm water discharge which the administrator determines contributes to a violation of a water quality standard or is a significant contributor of pollutants to surface waters of the state or where the administrator determines that storm water controls are needed for the discharge based on wasteload allocations that are part of TMDLs that address the pollutant(s) of concern; unless permission for a later date is granted by the administrator. (Wyoming Water Quality Rules and Regulations, Chapter 2 §6.a.vi)

4. The operator of an existing or new discharge composed entirely of storm water from an oil or gas exploration, production, processing, or treatment operation, or transmission facility is not required to submit a notice of intent in accordance with Section 4 or a permit application in accordance with Section 6 (b), unless the facility:
   a. (I) Has had a discharge of storm water resulting in the discharge of a reportable quantity for which notification is or was required pursuant to 40 CFR 117.21 or 40 CFR 302.6 at anytime since November 16, 1987; or
   b. (II) Has had a discharge of storm water resulting in the discharge of a reportable quantity for which notification is or was required pursuant to 40 CFR 110.6 at any time since November 16, 1987; or
   c. (III) Contributes to a violation of a water quality standard; or
   d. (IV) Has been determined by the administrator that storm water controls are needed for the discharge based on wasteload allocations that are part of TMDLs that address the pollutants of concern.
   e. (V) The construction of such facilities may still qualify for permit coverage under Section 6 (f).

   (Wyoming Water Quality Rules and Regulations, Chapter 2 §6.g.ii.M)

5. The administrator, at his discretion, may waive the otherwise applicable requirements in a general permit, as described in Section 4, for a storm water discharge from a small construction activity that disturbs less than five (5) acres where the value of the rainfall erosivity factor ('R' in the Revised Universal Soil Loss Equation) is less than five (5) during the period of construction activity. The rainfall erosivity factor must be determined in accordance with Chapter 2 of the *Agriculture Handbook Number 703, Predicting Soil Erosion by Water: A Guide to Conservation Planning With the Revised Universal Soil Loss Equation (RUSLE)*, pages 21-64, dated January 1997 or a similar state-approved method. The operator or owner must certify to the administrator that the construction activity will only take place during a period when the value of the rainfall erosivity factor is less than five (5). If unforeseeable conditions occur that are outside of the control of the applicant for a waiver, and that will extend the construction activity beyond the dates initially applied for, the owner or operator must reapply for the waiver or obtain coverage under a general permit for storm water discharges. The waiver re-application or permit application must be submitted within two (2) business days after the unforeseeable condition becomes known. This waiver does not relieve the operator or owner from complying with requirements of local agencies. (Wyoming Water Quality Rules and Regulations, Chapter 2 §6.f.ii.B)

6. For storm water discharges associated with large and/or small construction activities from point sources which discharge through a non-municipal or non-publicly owned separate storm sewer system, the director, at his discretion, may issue: a single WYPDES permit, with each discharger a co-permittee to a permit issued to the operator of the portion of the system that discharges into surface waters of the state; or, individual permits to

Table 2.10 (continued)

each discharger of storm water associated with large and/or small construction activity through the non-municipal conveyance system.

a. (A) Each facility with a storm water discharge to a storm water discharge system that is not an MS4 shall be covered by a WYPDES permit, or a permit issued to the operator of the portion of the system that discharges to surface waters of the state, with each discharger to the non-municipal conveyance a co-permittee to that permit.
b. (B) Where there is more than one (1) operator of a single system of such conveyances, all operators of storm water discharges associated with industrial activity must submit applications.
c. (C) Any permit covering more than one (1) operator shall identify the effluent limitations, or other permit conditions, if any, that apply to each operator.

(Wyoming Water Quality Rules and Regulations, Chapter 2 §6.f.v)

7. For storm water discharges associated with small construction activity identified in Section 6 (f) (ii) (A), the administrator may include permit conditions that incorporate qualifying state or local erosion and sediment control program requirements by reference. A qualifying state or local erosion and sediment control program is one that includes:
   a. (A) Requirements for construction site operators to implement appropriate erosion and sediment control best management practices;
   b. (B) Requirements for construction site operators to control waste such as discarded building materials, concrete truck washout, chemicals, litter, and sanitary waste at the construction site that may cause adverse impacts to water quality;
   c. (C) Requirements for construction site operators to develop and implement a storm water pollution prevention plan. (A storm water pollution prevention plan includes site descriptions, descriptions of appropriate control measures, copies of approved local requirements, maintenance procedures, inspection procedures, and identification of non-storm water discharges); and
   d. (D) Requirements to submit a site plan for review that incorporates consideration of potential water quality impacts.

   (Wyoming Water Quality Rules and Regulations, Chapter 2 §6.k.i)

   For storm water discharges from large construction activity identified in Section 6 (f) (i), the administrator may include permit conditions that incorporate qualifying state or local erosion and sediment control program requirements by reference. A qualifying state or local erosion and sediment control program is one that includes the elements listed in Section 6 (k) (i), and any additional requirements necessary to achieve the applicable technology-based standards of “best available technology” and “best conventional technology” based on the best professional judgment of the permit writer. (Wyoming Water Quality Rules and Regulations, Chapter 2 §6.k.ii)

TABLE 2.11

Shale Gas Site Equipment

Shale Gas Site Equipment								
Type	**Use**	**Height**	**Footprint**	**Powered By**	**Noise Output**	**Light Output**	**References**
Excavation Equipment	clear land for access, drilling, production, and operations			diesel			
Tractor Trailers, Flatbeds	transport drilling rig and equipment to site			diesel			
Generators	produce electricity for drill rig and lighting			diesel			Chesapeake Energy, March 2009; Air Emissions and Regulations.
Drilling Rig	drill well	100 feet		electricity			Chesapeake Energy, March 2009; Air Emissions and Regulations.
Mud Pumps	pumps drilling mud down hole						
Shale Shakers	separate cuttings and gas from drilling mud						
Production and Completion Truck-mounted Rig or Crane	run light tubing and support well-completion operations			diesel			
Wellhead / Christmas Tree	control gas flow from producing well	6 feet					
Lighting				electricity			
Water Injection Pumps	hydraulic fracturing			diesel			Chesapeake Energy, March 2009; Air Emissions and Regulations.
Tanker Trucks	water supply, gas, condensate, produced fluids, and frac fluid component transportation and storage			diesel			Chesapeake Energy, March 2009; Air Emissions and Regulations.
Separator	removes produced water			gravity			Chesapeake Energy, March 2009; Air Emissions and Regulations.
Pumps	move / pressurize fluid and gas						
Tri-ethylene glycol dehydrator	removes water from gas to meet gas pipeline specifications			natural gas			Chesapeake Energy, March 2009; Air Emissions and Regulations.
Wellhead Gas Compressor	raise gas pressure to the gas gathering line's required pressure			natural gas			Chesapeake Energy, March 2009; Air Emissions and Regulations.
Gas Lift Compressor	used, when necessary, to increase gas pressure so it can flow from the well			natural gas			City of Fort Worth, Texas, Code of Ordinances
Gas Compressor Station	compressors boost the pressure of the gas so it can flow to a user or local distribution company			natural gas			Chesapeake Energy, March 2009; Air Emissions and Regulations.
Gas Processor (refrigeration plant or expander plant)	condenses and removes heavier hydrocarbons (natural gas liquids) from rich gas			natural gas			Chesapeake Energy, March 2009; Air Emissions and Regulations.
Meters	measure gas, water, produced fluids, or condensates			often solar panels			
Perforating Tool	perforates the steel casing, cement sheath and rock formation in the production zone			electrical charges			Barnett Shale Energy Education Council (BSEEC); http://www.bseec.org/index.php/content/facts/drilling/
Front End Loader	move bulk materials			diesel			Chesapeake Energy, field visit, May 2009
Fork Lift	load, unload, and move materials			diesel			Chesapeake Energy, field visit, May 2009
Fracture Tanks	transport and store water supply, flow-back, and produced water			NA			Chesapeake Energy, field visit, May 2009
Wireline Truck	raise and lower tools in wellbore			diesel			Fortuna Energy, field visit, May 2009
Sand Trailers	transport and store propant			NA			Fortuna Energy, field visit, May 2009
Crane	move materials and equipment			diesel			Fortuna Energy, field visit, May 2009
Lift truck	elevated work platform			electric			Fortuna Energy, field visit, May 2009

TABLE 2.12

Radionuclide Half-Lives

Radionuclide	Half-life	Mode of Decay
Ra-226	1600 years	alpha
Rn-222	3,824 days	alpha
Pb-210	22.30 years	beta
Po-210	138.40 days	alpha
Ra-228	5.75 years	beta
Th-228	1.92 years	alpha
Ra-224	3.66 days	alpha

TABLE 3.1
Summary of Regulations Pertaining to Transfer of Invasive Species

Agency	Document		Article	Regulation Summary
SRBC	Federal Register, Vol 73, No. 247, Rules and Regulations		18 CFR Part 806.22,f,8	All flowback and produced fluids, including brines, must be treated and disposed of in accordance with applicable state and federal law.
SRBC	Regulation of Projects		18 CFR Part 806.24,b,3,c	For diversions into the SRB, must provide: (1) the source, amount, and location of the diverted water,and (2) the water quality classification, if any, of the SRBC discharge stream and the discharge location(s). (3) All applicable withdrawal or discharge permits or approvals must have been applied for or received, and must prove that the diversior will not result in water quality degradation that may be injurious to any existing or potential ground or surface water use.
SRBC	Regulation of Projects		18 CFR Part 801.3,b	The SRBC will require evidence that proposed interbasin transfers of water will not jeopardize, impair or limit the efficient development and management of the SRBC's water resources, or any aspects of these resources for in-basin use, or have a significant unfavorable impact on the resources of the basin and the receiving waters of the Chesapeake Bay.
SRBC	Regulation of Projects		18 CFR Part 801.3,c,1	Allocations, diversions, or withdrawals of water must be based on (1) the rights of landholders in any watershed to use the stream water in reasonable amounts and to have the stream flow not unreasonably diminished in quality or quantity by upstream use or diversion of water; and (2) on the maintenance of the historic seasonal variations of the flows into Chesapeake Bay.
SRBC	Regulation of Projects		18 CFR Part 806.23,2	The SRBC may deny or limit an approval if a withdrawal may cause significant adverse impacts to SRB water, including: lowering of groundwater or stream flow levels; rendering competing supplies unreliable; affecting other water uses; causing water quality degradation that may be injurious to any existing or potential water use; affecting any living resources or their habitat; causing permanent loss of aquifer storage capacity; or affecting low flow of perennial or intermittent streams.
SRBC	Federal Register, Vol 73, No. 247, Rules and Regulations		18 CFR Part 806.22,f,6	Flowback fluids or produced brines used for hydrofracturing must be separately accounted for, but will not be included in the daily use volume or be subject to the mitigation requirements of § 806.22 [b].
SRBC	Standard Docket Conditions Contained In Gas Well **Consumptive Water Use**	*	Item 10.	Unused water shall not be discharged back to the SRB waters without appropriate controls and treatment to prevent the spread of aquatic nuisance species.
SRBC	Regulation of Projects		18 CFR Part 806.25,b, 4	Industrial water users must evaluate and utilize applicable recirculation and reuse practices.
SRBC	Standard Docket Conditions Contained In Gas Well **Surface Water** Dockets		Item 4. (Not contained in all approvals)	Within ninety (90) days of this approval, the project sponsor shall submit a plan of study and a schedule for completion to conduct a survey and evaluate the potential impacts on the rare and protected freshwater mussels located in the Susquehanna River within the area of the withdrawal.
SRBC	Standard Docket Conditions Contained In Gas Well **Surface Water** Dockets		Item 5. (Not contained in all approvals)	This approval does not become effective until the SRBC is satisfied that the withdrawal has no adverse impacts to the rare and protected freshwater mussel species of concern.
SRBC	Standard Docket Conditions Contained In Gas Well **Surface Water** Dockets	*	Item 10.	Must report the method of water transport (tanker truck or pipeline) and show that all water withdrawn from surface water sources is transported, stored, injected into a well, or discharged with appropriate controls and treatment to prevent the spread of aquatic nuisance species.
DRBC	Water Code 18 CFR Part 410		2.20.2	The underground water-bearing formations of the DRB, their waters, storage capacity, recharge areas, and ability to convey water shall be preserved and protected.
DRBC	Water Code 18 CFR Part 410		2.20.3	Projects that withdraw underground waters must reasonably safeguard the present and future public interest in the affected water resources.
DRBC	Water Code 18 CFR Part 410		2.20.4	Withdrawals from DRB ground water are limited to the maximum draft of all withdrawals from a ground water basin, aquifer, or aquifer system that can be sustained without rendering supplies unreliable, causing long-term progressive lowering of ground water levels, water quality degradation, permanent loss of storage capacity, or substantial impact on low flows of perennial streams, unless the DRBC decides a withdrawal is in the public interest. In confined coastal plain aquifers, the DRBC may apply aquifer management levels, if any, established by a signatory state in determining compliance with criteria relating to "longterm progressive lowering of ground water levels."
DRBC	Water Code 18 CFR Part 410		2.20.5	The principal natural recharge areas of the DRB shall be protected from unreasonable interference. No recharge sources (ground or surface water) shall be polluted based on water quality standards promulgated by the DRBC or any of the signatory parties.
DRBC	Water Code 18 CFR Part 410		2.20.6	The DRB ground water resources shall be used, conserved, developed, managed, and controlled for the needs of present and future generations, so interference, impairment, penetration, or artificial recharge shall be subject to review and evaluation under the Compact.
DRBC	Water Code 18 CFR Part 410		2.10.1	The DRBC may acquire, operate and control projects and facilities for the storage and release of waters, for the regulation of flows and DRB surface and ground water supplies, for the protection of public health, stream quality control, economic development, improvement of fisheries, recreation, pollution dilution and abatement, the prevention of undue salinity and other purposes. No signatory party may permit any augmentation of flow to be diminished by the diversion of any DRB water during any period in which waters are being released from storage by the DRBC for the purpose of augmenting such flow, except in cases where such diversion is authorized by this compact, or by the DRBC pursuant to, or by the order of a court of competent jurisdiction.

Agency	Document	Article	Regulation Summary
DRBC	Water Code 18 CFR Part 410	2.30.2	The waters of the DRB are limited in quantity and to drought. The exportation of DRB water is discouraged. The DRB waters have limited assimilative capacity to accept substances without significant impacts. Wastewater import that would significantly reduce the assimilative capacity of the receiving DRB stream is discouraged and should be reserved for users within the DRB.
DRBC	Water Code 18 CFR Part 410	2.30.3	Consideration of the importation or exportation of water will be conducted pursuant to this policy and include assessments of the water resource and economic impacts of the project and of all alternatives to any water exportation or wastewater importation project.
DRBC	Water Code 18 CFR Part 410	2.30.4	The DRBC has jurisdiction over exportations and importations of water (Section 3.8 of the Compact, and inclusion within the Comprehensive Plan) as specified in the Administrative Manual - Rules of Practice and Procedure. The applicant shall address those of the items listed below as directed by the DRBC: A. efforts to develop or use and conserve outside resources; B. water resource, economic, and social impacts of each alternative, including the "no project" alternative; D. amount, timing and duration of the proposed transfer and its relationship to DRB hydrologic conditions, and impact on instream uses and downstream waste assimilation capacity; E. benefits to the DRB as a result of the proposed transfer; F. volume of the transfer and its relationship to other specified actions or Resolutions by the DRBC; G. the relationship of the transfer volume to all other diversions; H. other significant benefits or impairments to the DRB as a result of the proposed transfer.
DRBC	Water Code 18 CFR Part 410	2.30.6	The DRBC gives no credit toward meeting wastewater treatment requirements for wastewater imported into the Delaware Basin. Wasteload allocations assigned to dischargers will not include loadings attributable to wastewater importation.
DRBC	Water Code 18 CFR Part 410	2.200.1	DRB water quality will be maintained in a safe and satisfactory condition for...wildlife, fish and other aquatic life.
DRBC	Water Code 18 CFR Part 410	2.350.2	The DRBC will preserve and protect wetlands by: A. minimizing adverse alterations in the quantity and quality of the underlying soils and natural flow of waters that nourish wetlands; B. safeguarding against adverse draining, dredging or filling practices, liquid or solid waste management practices, and siltation; C. preventing the excessive addition of pesticides, salts or toxic materials arising from non-point source wastes; and D. preventing destructive construction activities.
DRBC	Water Code 18 CFR Part 410	2.400.2	The drought of record, which occurred in the period 1961-1967, shall be the basis for planning and development of facilities and programs for control of salinity in the Delaware Estuary.
DRBC	Water Code 18 CFR Part 410	3.10.3,A,1	The DRBC maintains the quality of interstate waters, where existing quality is better than the established stream quality objectives, unless such change is justifiable as a resul of necessary economic or social development or to improve significantly another body of water. The DRBC will require the highest degree of waste treatment practicable. No change will be considered which would be injurious to any designated present or future use.
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,b	There will be no measurable change in water quality except towards natural conditions in water that has high scenic, recreational, ecological, and/or water supply values. Waters with exceptional values may be classified as either **Outstanding Basin Waters (OBW) or Significant Resource Waters (SRW)**. OBW shall be maintained at their existing water quality. 2) SRW must not be degraded below existing water quality, although localized degradation of water quality may be allowed for initial dilution if the DRBC, after consultation with the state NPDES permitting agency, finds that the public interest warrants these changes, unless a mixing zone is allowed and then to the exten of the mixing zone designated as set forth in this section. If degradation of water quality is allowed for initial dilution purposes, the DRBC, will designate mixing zones for each point source and require the highest possible point source treatment levels necessary to limit the size and extent of the mixing zones. The dimensions of the mixing zone will be based upon an evaluation of (a) site specific conditions, including channel characteristics; (b) the cost and feasibility of treatment technologies; and (c) the design of the dis
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,c	1) Direct discharges of wastewater to **Special Protection Waters (SPW)** are discouraged. New wastewater treatment facilities and substantial alterations to existing facilities that discharge directly to SPW may be approved after the applicant has evaluated all nondischarge/ load reduction alternatives and is unable to implement these alternatives because of technical and/or financial infeasibility. 2) New wastewater treatment facilities and substantial alterations to existing facilities within the drainage area of SPW may be approved after the applicant fully evaluated all natural treatment alternatives and is unable to implement them because of technical and/or financial infeasibility. **For both 1) and 2)** above, the applicant will consider alternatives to all loadings – both existing and proposed – in excess of actual loadings at the time of SPW designation. 3) New wastewater treatment facilities and substantial alterations to existing facilities discharging directly to SRW may be approved only following a determination that the project is in the public interest as that term is defined in Section 3.10.3.A.2.a.5 4) The general number, location and size of future wastewater treatment facilities discharging to OBW (if ar
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,d	Addresses emergency systems (standby power facilities, alarms, emergency management plans) for wastewater treatment facilities discharging to SPW. Emergency management plans shall include an emergency notification procedure covering all affected downstream users. The minimum level of wastewater treatment for new wastewate treatment facilities and substantial alterations to existing wastewater treatment facilities that discharge directly to OBW or SRW will be **Best Demonstrable Technology (BDT)** (See rule for chemical analyses results that define BDT.) BDT may be superseded by applicable federal, state or DRBC criteria that are more stringent. BDT for disinfection - ultraviolet light disinfection or an equivalent disinfection process that results in no harm to aquatic life, does not produce toxic chemical residuals, and results in effective bacterial and viral destruction. DRBC may approve effluent trading on a voluntary basis between point sources within the same watershed or between the same Interstate or Boundary Control Points to achieve no measurable change to existing water quality. Regulation discusses facilities within drainage areas of SPW and discharges to OBW and SRW and lists water quality control points and the analyses parameters.
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,e	1) Projects subject to review under Section 3.8 of the Compact that are located in the drainage area of SPW must submit for approval a Non-Point Source Pollution Control Plan that controls the new or increased non-point source loads generated within the portion of the project's service area which is also located within the drainage area of SPW The plan will state which BMPs must be used to control the non-point source loads. RULE DISCUSSES trade-off plans in detail. It discusses: projects located above major

Agency	Document	Article	Regulation Summary
			surface water impoundments; projects located in municipalities that have adopted and are actively implementing non-point source/stormwater control ordinances, projects located in watersheds where the applicable state environmental agency, county government, and local municipalities are participating in the development of a watershed plan. 2) Approval of a new or expanded water withdrawal and/or wastewater discharge project will be subject to the condition that any new connection to the project system only serve an area(s) regulated by a non-point source pollution control plan which has been approved by the DRBC. 3) Future plans for SPWs non-point source control regulations
DRBC	Water Code 18 CFR Part 410	3.10.3B	DRB waters will not contain substances attributable to municipal, industrial, or other discharges in concentrations or amounts sufficient to preclude the protection of specified water uses. a. The waters shall be substantially free from unsightly or malodorous nuisances due to floating solids, sludge deposits, debris, oil, scum, substances in concentrations or combinations which are toxic or harmful to human, animal, plant, or aquatic life, or that produce color, taste, odor of the water, or taint fish or shellfish flesh. b. The concentration of total dissolved solids, except intermittent streams, shall not exceed 133 percent of background. In no case shall concentrations of substances exceed those values given for rejection of water supplies in the United States Public Health Service Drinking Water Standards.
DRBC	Water Code 18 CFR Part 410	3.10.3C	The DRBC designates numerical stream quality objectives for the protection of aquatic life for the Delaware River Estuary (Zones 2 through 5) which correspond to the designated uses of each zone. Aquatic life objectives for the protection from both acute and chronic effects are herein established on a pollutant-specific basis. (See RULE)
DRBC	Water Code 18 CFR Part 410	3.10.3D	The DRBC designates numerical stream quality objectives for the protection of human health for the Delaware River Estuary (Zones 2 through 5) which correspond to the designated uses of each zone. Stream quality objectives for protection from both carcinogenic and systemic effects are herein established on a pollutant-specific basis. (See RULE)
DRBC	Water Code 18 CFR Part 410	3.10.4,A	All wastes shall receive a minimum of secondary treatment, regardless of the stated stream quality objective.
DRBC	Water Code 18 CFR Part 410	3.10.4,B	Wastes (exclusive of stormwater bypass) containing human excreta or disease producing organisms shall be effectively disinfected before being discharged into surface bodies of water as needed to meet applicable DRBC or State water quality standards.
DRBC	Water Code 18 CFR Part 410	3.10.4,C	Effluents shall not create a menace to public health or safety at the point of discharge.
DRBC	Water Code 18 CFR Part 410	3.10.4,D	Lists discharge contaminant limits.
DRBC	Water Code 18 CFR Part 410	3.10.4,E	Where necessary to meet the stream quality objectives, the waste assimilative capacity of the receiving waters shall be allocated in accordance with the doctrine of equitable apportionment.
DRBC	Water Code 18 CFR Part 410	3.10.4,F	1. Discharges to intermittent streams may be permitted by the DRBC only if the applicant can demonstrate that there is no reasonable economical alternative, the project is environmentally acceptable, and would not violate the stream quality objectives set forth in Section 3.10.3B.1.a. 2. Discharges to intermittent streams shall be adequately treated to protect stream uses, public health and ground water quality, and prevent nuisance conditions.
DRBC	Water Code 18 CFR Part 410	3.10.5,E	The DRBC will consider requests to modify the stream quality objectives for toxic pollutants based upon site-specific factors. Such requests shall provide a demonstration of the site-specific differences in the physical, chemical or biological characteristics of the area in question, through the submission of substantial scientific data and analysis. The demonstration shall also include the proposed alternate stream quality objectives. The methodology and form of the demonstration shall be approved by the DRBC.
NYSDEC	6 NYCRR Part 608	608.9	(a) Water quality certifications required by Section 401 of the Federal Water Pollution Control Act, Title 33 United States Code 1341(see subdivision (c)of this Section). Any applicant for a federal license or permit to conduct any activity, including but not limited to the construction or operation of facilities that may result in any discharge into navigable waters as defined in Section 502 of the Federal Water Pollution Control Act (33 USC 1362), must apply for and obtain a water quality certification from the department.The applicant must demonstrate compliance with Sections 301-303, 306 and 307 of the Federal Water Pollution Control Act (See RULE.)

* Connotes the indicated regulation pertains directly to invasive or nuisance species. All other regulations reference practices, methods, and actions that are not specifically targeted at reducing or eliminating the transport of invasive species, but nonetheless may indirectly address the issue.

Table 3.2
Regulations Pertaining to Watershed Withdrawal

Agency	Potential Impacts of Reduced Stream Flow	Denigration of Stream's Designated Best Use	Potential Impacts to Downstream Wetlands	Potential Impacts to Fish and Wildlife	Potential Aquifer Depletion
DRBC	Water Code §2.50.2.A Water Code §2.1.1 Water Code §2.5	Water Code, 18 CFR §410 DRBC Compact	Water Code §2.350	Water Code §2.1.1 Water Code §2.200.1 Water Code §3.10.2.B Water Code §3.10.3.A.2 Water Code §3.10.3.A.2.e Water Code §3.30.4.A.1 Water Code §2.1.2 Water Code §3.10.3.A.2.b Water Code 3.20 Water Code 3.30 Water Code 3.40 Water Code 3.30.4.A.1	Water Code §2.50.2.A Water Code §2.20
NYSDEC	6 NYCRR §675 6 NYCRR §605 6 NYCRR §666	6 NYCRR §608 6NYCRR §666	6 NYCRR §663 6 NYCRR §664 6 NYCRR §665	6 NYCRR §595 6 NYCRR §608 6NYCRR §666	Env. Conservation Law §15-15 Env. Conservation Law §15-1528 6 NYCRR §666
SRBC	Reg. of Projects §806.30 Reg. of Projects §801.3 Reg. of Projects §806.23	Reg. of Projects, 18 CFR §801, §806, §807, §808	Reg. of Projects §801.8 Reg. of Projects §806.14	Reg. of Projects §806.23.b.2 Policy 2003_1 Reg. of Projects §801.9 Reg. of Projects §806.14.b.1.v.C	Reg. of Projects §806.23.b.2 Reg. of Projects §806.12 Reg. of Projects §806.22

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Albany	Albany, City of	4/15/1980
Albany	Altamont, Village of	8/15/1983
Albany	Berne,Town of	8/1/1987 (L)
Albany	Bethlehem, Town of	4/17/1984
Albany	Coeymans, Town of	8/3/1989
Albany	Cohoes, City of	12/4/1979
Albany	Colonie, Town of	9/5/1979
Albany	Green Island, Village of	6/4/1980
Albany	Guilderland, Town of	1/6/1983
Albany	Knox, Township of	8/13/1982 (M)
Albany	Menands, Village of	3/18/1980
Albany	New Scotland, Town of	12/1/1982
Albany	Ravena, Village of	4/2/1982 (M)
Albany	Rensselaerville, Town of	8/27/1982 (M)
Albany	Voorheesville, Village of	12/1/1982
Albany	Watervliet, City of	1/2/1980
Albany	Westerlo, Town of	8/3/1989
Allegany	Alfred, Town of	10/7/1983 (M)
Allegany	Alfred, Village of	2/15/1980
Allegany	Allen, Town of	7/16/1982 (M)
Allegany	Alma, Town of	10/7/1983 (M)
Allegany	Almond, Village of	2/15/1980
Allegany	Amity, Town of	12/18/1984
Allegany	Andover, Town of	3/2/1998
Allegany	Andover, Village of	4/2/1979
Allegany	Angelica, Town of	12/31/1982 (M)
Allegany	Angelica, Village of	2/1/1984
Allegany	Belfast, Town of	8/6/1982 (M)
Allegany	Belmont, Village of	12/18/1984
Allegany	Birdsall, Town of	7/16/1982 (M)
Allegany	Bolivar, Town of	7/30/1982 (M)
Allegany	Bolivar, Village of	1/19/1996
Allegany	Burns, Town of	7/16/1982 (M)
Allegany	Canaseraga, Village of	12/2/1983 (M)
Allegany	Caneadea, Town of	8/20/1982 (M)
Allegany	Clarksville, Town of	11/12/1982 (M)
Allegany	Cuba, Town of	7/30/1982 (M)
Allegany	Cuba, Village of	4/17/1978
Allegany	Friendship, Town of	12/18/1984
Allegany	Genesee, Town of	7/30/1982 (M)
Allegany	Granger, Town of	10/7/1983 (M)
Allegany	Grove, Town of	11/6/1991
Allegany	Hume, Town of	10/2/1997
Allegany	Independence, Town of	7/9/1982 (M)
Allegany	New Hudson, Town of	8/20/1982 (M)
Allegany	Richburg, Village of	1/5/1978
Allegany	Rushford, Town of	12/23/1983 (M)
Allegany	Scio, Town of	3/18/1985
Allegany	Ward,Town of	(NSFHA)
Allegany	Wellsville, Town of	3/18/1985
Allegany	Wellsville, Village of	7/17/1978

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Allegany	West Almond, Town of	(NSFHA)
Allegany	Willing, Town of	12/24/1982 (M)
Allegany	Wirt, Town of	6/25/1982 (M)
Broome	Barker, Town of	2/5/1992
Broome	Binghamton, City of	6/1/1977
Broome	Binghamton, Town of	1/6/1984 (M)
Broome	Chenango, Town of	8/17/1981
Broome	Colesville, Town of	1/20/1993
Broome	Conklin, Town of	7/17/1981
Broome	Dickinson, Town of	4/15/1977
Broome	Endicott, Village of	9/7/1998
Broome	Fenton, Town of	8/3/1981
Broome	Johnson City, Village of	9/30/1977
Broome	Kirkwood, Town of	6/1/1977
Broome	Lisle, Town of	8/20/2002
Broome	Lisle, Village of	1/6/1984 (M)
Broome	Maine, Town of	2/5/1992
Broome	Nanticoke, Town of	12/18/1985
Broome	Port Dickinson, Village of	5/2/1977
Broome	Sanford, Town of	6/4/1980
Broome	Triangle, Town of	7/20/1984 (M)
Broome	Union, Town of	9/30/1988
Broome	Vestal, Town of	3/2/1998
Broome	Whitney Point, Village of	1/6/1984 (M)
Broome	Windsor, Town of	9/30/1992
Broome	Windsor, Village of	5/18/1992
Cattaraugus	Allegany, Town of	11/15/1978
Cattaraugus	Allegany, Village of	12/17/1991
Cattaragus	Ashford, Township of	5/25/1984
Cattaraugus	Carrollton, Town of	3/18/1983 (M)
Cattaraugus	Cattaraugus, Village of	4/20/1984 (M)
Cattaraugus	Cold Spring, Town of	3/1/1978
Cattaraugus	Conewango, Town of	7/30/1982 (M)
Cattaraugus	Dayton, Town of	5/25/1984 (M)
Cattaraugus	Delevan, Village of	1/20/1984 (M)
Cattaraugus	East Otto, Town of	4/20/1984 (M)
Cattaraugus	East Randolph, Village of	2/1/1978
Cattaraugus	Ellicottville, Town of	1/19/2000
Cattaraugus	Ellicottville, Village of	5/2/1994
Cattaraugus	Farmersville, Town of	7/23/1982 (M)
Cattaraugus	Franklinville, Town of	7/17/1978
Cattaraugus	Franklinville, Village of	7/3/1978
Cattaraugus	Freedom, Town of	8/19/1991
Cattaraugus	Great Valley, Town of	7/17/1978
Cattaraugus	Hinsdale, Town of	1/17/1979
Cattaraugus	Humphrey, Town of	8/13/1982 (M)
Cattaraugus	Ischua, Town of	8/15/1978
Cattaraugus	Leon, Town of	8/13/1982 (M)
Cattaraugus	Limestone, Village of	4/17/1978
Cattaraugus	Little Valley, Town of	6/22/1984 (M)
Cattaraugus	Little Valley, Village of	2/1/1978

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Cattaraugus	Lyndon, Town of	7/16/1982 (M)
Cattaraugus	Machias, Town of	8/20/1982 (M)
Cattaraugus	Mansfield, Town of	5/25/1984 (M)
Cattaraugus	Napoli, Town of	7/2/1982 (M)
Cattaraugus	New Albion, Town of	12/3/1982 (M)
Cattaraugus	Olean, City of	5/9/1980
Cattaraugus	Olean, Town of	2/1/1979
Cattaraugus	Otto, Town of	4/20/1984 (M)
Cattaraugus	Perrysburg, Town of	4/20/1984 (M)
Cattaraugus	Persia, Town of	4/20/1984 (M)
Cattaraugus	Portville, Town of	7/18/1983
Cattaraugus	Portville, Village of	4/17/1978
Cattaraugus	Randolph, Town of	11/5/1982 (M)
Cattaraugus	Randolph, Village of	8/1/1978
Cattaraugus	Salamanca, City of	4/17/1978
Cattaraugus	Salamanca, Town of	11/1/1979
Cattaraugus	South Dayton, Village of	1/5/1978
Cattaraugus	South Valley, Town of	12/2/1983 (M)
Cattaraugus	Yorkshire, Town of	5/25/1984 (M)
Cattaraugus/Erie/ Chautauqua/Allegany	Seneca Nation of Indians	9/30/1988
Cayuga	Auburn, City of	8/2/2007
Cayuga	Aurelius, Town of	8/2/2007
Cayuga	Aurora, Village of	8/2/2007
Cayuga	Brutus, Town of	8/2/2007
Cayuga	Cato, Town of	8/2/2007
Cayuga	Cato, Village of	8/2/2007
Cayuga	Cayuga, Village of	8/2/2007
Cayuga	Conquest, Town of	8/2/2007
Cayuga	Fair Haven, Village of	8/2/2007
Cayuga	Fleming, Town of	8/2/2007
Cayuga	Genoa,Town of	8/2/2007
Cayuga	Ira, Town of	8/2/2007
Cayuga	Ledyard, Town of	8/2/2007
Cayuga	Locke, Town of	8/2/2007
Cayuga	Mentz, Town of	8/2/2007
Cayuga	Meridian, Village of	8/2/2007
Cayuga	Montezuma, Town of	8/2/2007
Cayuga	Moravia, Town of	8/2/2007
Cayuga	Moravia, Village of	8/2/2007
Cayuga	Niles, Town of	8/2/2007
Cayuga	Owasco, Town of	8/2/2007
Cayuga	Port Byron, Village of	8/2/2007
Cayuga	Scipio, Town of	8/2/2007
Cayuga	Sempronius, Town of	8/2/2007
Cayuga	Sennett, Town of	8/2/2007
Cayuga	Springport, Town of	8/2/2007
Cayuga	Sterling, Town of	8/2/2007
Cayuga	Summer Hill, Town of	8/2/2007
Cayuga	Throop, Town of	8/2/2007
Cayuga	Union Springs, Village of	8/2/2007

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Cayuga	Venice, Town of	8/2/2007
Cayuga	Victory, Town of	8/2/2007
Cayuga	Weedsport, Village of	8/2/2007
Chautauqua	Arkwright, Town of	4/8/1983 (M)
Chautauqua	Bemus Point, Village of	11/2/1977
Chautauqua	Brocton, Village of	(NSFHA)
Chautauqua	Busti, Town of	1/20/1993
Chautauqua	Carroll, Town of	10/29/1982 (M)
Chautauqua	Cassadaga, Village of	12/1/1977
Chautauqua	Celoron, Village of	3/18/1980
Chautauqua	Charlotte, Town of	3/23/1984 (M)
Chautauqua	Chautauqua, Town of	6/15/1984
Chautauqua	Cherry Creek, Town of	7/2/1982 (M)
Chautauqua	Cherry Creek, Village of	2/15/1978
Chautauqua	Clymer, Town of	10/7/1983 (M)
Chautauqua	Dunkirk, City of	2/4/1981
Chautauqua	Dunkirk, Town of	8/6/1982 (M)
Chautauqua	Ellery, Town of	3/18/1980
Chautauqua	Ellicott, Town of	8/1/1984
Chautauqua	Ellington, Town of	10/7/1983 (M)
Chautauqua	Falconer, Village of	1/5/1978
Chautauqua	Forestville, Village of	3/18/1983 (M)
Chautauqua	Fredonia, Village of	11/15/1989
Chautauqua	French Creek, Town of	6/8/1984 (M)
Chautauqua	Gerry, Town of	1/6/1984 (M)
Chautauqua	Hanover, Town of	12/18/1984
Chautauqua	Harmony, Township of	12/1/1986 (L)
Chautauqua	Jamestown, City of	6/1/1978
Chautauqua	Kiantone, Town of	2/2/1996
Chautauqua	Lakewood, Village of	11/2/1977
Chautauqua	Mayville, Village of	1/5/1978
Chautauqua	Mina, Town of	1/2/2003
Chautauqua	North Harmony, Town of	2/15/1980
Chautauqua	Panama, Village of	3/1/1978
Chautauqua	Poland, Town of	3/11/1983 (M)
Chautauqua	Pomfret, Town of	12/18/1984
Chautauqua	Portland, Town of	10/7/1983 (M)
Chautauqua	Ripley,Town of	(NSFHA)
Chautauqua	Sheridan, Town of	10/7/1983 (M)
Chautauqua	Sherman, Village of	3/1/1978
Chautauqua	Sherman,Town of	1/6/1984 (M)
Chautauqua	Silver Creek, Village of	8/1/1983
Chautauqua	Sinclairville, Village of	12/1/1977
Chautauqua	Stockton, Town of	10/21/1983 (M)
Chautauqua	Villenova, Town of	5/21/1982 (M)
Chautauqua	Westfield, Town of	6/8/1984 (M)
Chautauqua	Westfield, Village of	10/7/1983 (M)
Chemung	Ashland, Town of	1/16/1980
Chemung	Baldwin, Town of	7/23/1982 (M)
Chemung	Big Flats, Town of	8/18/1992
Chemung	Catlin, Town of	6/22/1984 (M)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Chemung	Chemung, Town of	9/3/1980
Chemung	Elmira Heights, Village of	9/29/1996
Chemung	Elmira, City of	4/2/1997
Chemung	Elmira, Town of	9/29/1996
Chemung	Erin, Town of	8/13/1982 (M)
Chemung	Horseheads, Town of	9/29/1996
Chemung	Horseheads, Village of	9/29/1996
Chemung	Millport, Village of	6/15/1988 (M)
Chemung	Southport, Town of	8/5/1991
Chemung	Van Etten, Town of	9/28/1979 (M)
Chemung	Van Etten, Village of	7/1/1988 (L)
Chemung	Veteran, Town of	2/18/1983 (M)
Chemung	Wellsburg, Village of	6/15/1981
Chenango	Afton, Town of	9/30/1992
Chenango	Afton, Village of	9/30/1992
Chenango	Bainbridge, Town of	12/3/1991
Chenango	Bainbridge, Village of	6/2/1993
Chenango	Columbus, Town of	4/8/1983 (M)
Chenango	Coventry, Town of	10/15/1985 (M)
Chenango	Earlville, Village of	6/5/1985 (S)
Chenango	German, Town of	9/24/1984 (M)
Chenango	Greene, Town of	8/3/1981
Chenango	Greene, Village of	8/3/1981
Chenango	Guilford, Town of	7/6/1984 (M)
Chenango	Lincklaen, Town of	3/23/1984 (M)
Chenango	Mc Donough, Town of	6/5/1985 (M)
Chenango	New Berlin, Town of	6/5/1985 (M)
Chenango	New Berlin, Village of	11/4/1983 (M)
Chenango	North Norwich, Town of	12/3/1991
Chenango	Norwich, City of	12/18/1985
Chenango	Norwich, Town of	11/15/1984
Chenango	Otselic, Town of	6/5/1985 (M)
Chenango	Oxford, Town of	8/24/1984 (M)
Chenango	Oxford, Village of	9/10/1984 (M)
Chenango	Pharsalia, Town of	8/24/1984 (S)
Chenango	Pitcher, Town of	3/4/1986 (M)
Chenango	Plymouth, Town of	11/4/1983 (M)
Chenango	Preston, Town of	4/1/1983 (M)
Chenango	Sherburne, Town of	8/24/1984 (M)
Chenango	Sherburne, Village of	9/10/1984 (M)
Chenango	Smithville, Town of	11/4/1983 (M)
Chenango	Smyrna, Town of	9/24/1984 (M)
Chenango	Smyrna, Village of	10/15/1985 (M)
Clinton	Altona, Town of	9/28/2007 (M)
Clinton	Ausable, Town of	9/28/2007 (M)
Clinton	Beekmantown, Town of	9/28/2007
Clinton	Black Brook, Town of	9/28/2007
Clinton	Champlain, Town of	9/28/2007
Clinton	Champlain, Village of	9/28/2007
Clinton	Chazy, Town of	9/28/2007
Clinton	Clinton, Town of	9/28/2007 (M)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Clinton	Ellenburg, Town of	9/28/2007 (M)
Clinton	Mooers, Town of	9/28/2007 (M)
Clinton	Peru,Town of	9/28/2007
Clinton	Plattsburgh, City of	9/28/2007
Clinton	Plattsburgh, Town of	9/28/2007
Clinton	Rouses Point, Village of	9/28/2007
Clinton	Saranac, Town of	9/28/2007
Clinton	Schuyler Falls, Town of	9/28/2007
Columbia	Ancram, Town of	6/5/1985 (M)
Columbia	Austerlitz, Town of	6/5/1985 (M)
Columbia	Canaan, Town of	7/3/1985 (M)
Columbia	Chatham, Town of	9/15/1993
Columbia	Chatham, Village of	12/15/1982
Columbia	Claverack, Town of	9/6/1989
Columbia	Clermont, Township of	9/5/1984
Columbia	Copake, Town of	6/19/1985 (M)
Columbia	Gallatin, Town of	10/16/1984
Columbia	Germantown, Town of	5/11/1979 (M)
Columbia	Ghent, Town of	1/1/1988 (L)
Columbia	Greenport, Town of	11/15/1989
Columbia	Hillsdale, Town of	5/15/1985 (M)
Columbia	Hudson, City of	9/29/1989
Columbia	Kinderhook, Town of	12/1/1982
Columbia	Kinderhook, Village of	12/1/1982
Columbia	Livingston, Town of	5/11/1979 (M)
Columbia	New Lebanon, Town of	6/5/1985 (M)
Columbia	Stockport, Town of	1/19/1983
Columbia	Stuyvesant, Town of	9/14/1979 (M)
Columbia	Taghkanic, Town of	1/3/1986 (M)
Columbia	Valatie, Village of	12/1/1982
Cortland	Cincinnatus, Town of	5/15/1985 (M)
Cortland	Cortland, City of	8/15/1983
Cortland	Cortlandville, Town of	8/15/1983
Cortland	Cuyler, Town of	5/15/1985
Cortland	Freetown, Town of	1/17/1975
Cortland	Harford, Town of	5/15/1985 (M)
Cortland	Homer, Town of	8/15/1983
Cortland	Homer, Village of	8/15/1983
Cortland	Lapeer, Town of	7/20/1984 (M)
Cortland	Marathon, Town of	5/15/1985 (S)
Cortland	Marathon, Village of	10/15/1982
Cortland	Mcgraw, Village of	12/1/1982
Cortland	Preble, Town of	5/15/1985 (M)
Cortland	Scott, Town of	5/15/1985 (M)
Cortland	Solon, Town of	5/15/1985
Cortland	Taylor, Town of	5/15/1985 (M)
Cortland	Truxton, Town of	5/15/1985 (M)
Cortland	Virgil, Town of	5/15/1985 (M)
Cortland	Willet, Town of	7/20/1984 (M)
Delaware	Andes, Town of	5/1/1985 (M)
Delaware	Andes, Village of	4/1/1986 (L)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Delaware	Bovina, Town of	5/1/1985 (M)
Delaware	Colchester,Town of	2/4/1987
Delaware	Davenport, Town of	2/2/2002
Delaware	Delhi, Town of	7/18/1985
Delaware	Delhi, Village of	7/18/1985
Delaware	Deposit, Town of	3/18/1986 (M)
Delaware	Fleischmanns, Village of	1/17/1986 (M)
Delaware	Franklin, Town of	4/1/1988 (L)
Delaware	Franklin, Village of	8/1/1987 (L)
Delaware	Hamden,Town of	3/4/1986 (M)
Delaware	Hancock, Town of	9/28/1990
Delaware	Hancock, Village of	9/28/1990
Delaware	Harpersfield, Town of	6/5/1985 (M)
Delaware	Hobart, Village of	5/15/1985 (M)
Delaware	Kortright, Town of	5/15/1985 (M)
Delaware	Margaretville, Village of	6/4/1990
Delaware	Masonville, Town of	11/1/1985 (M)
Delaware	Meredith, Town of	5/15/1985 (M)
Delaware	Middletown, Town of	8/2/1993
Delaware	Roxbury, Town of	5/15/1985 (M)
Delaware	Sidney, Town of	9/30/1987
Delaware	Sidney, Village of	9/30/1987
Delaware	Stamford, Town of	10/1/1986 (L)
Delaware	Stamford, Village of	8/1/1987 (L)
Delaware	Tompkins, Town of	11/15/1985 (M)
Delaware	Walton, Town of	9/2/1988
Delaware	Walton, Village of	4/2/1991
Delaware/Broome	Deposit, Village of	2/1/1979
Dutchess	Amenia, Town of	11/15/1989
Dutchess	Beacon, City of	3/1/1984
Dutchess	Beekman, Town of	9/5/1984
Dutchess	Clinton, Town of	7/5/1984
Dutchess	Dover, Town of	7/4/1988
Dutchess	East Fishkill, Town of	6/15/1984
Dutchess	Fishkill, Town of	6/1/1984
Dutchess	Fishkill, Village of	3/15/1984
Dutchess	Hyde Park, Town of	6/15/1984
Dutchess	Lagrange, Town of	9/8/1999
Dutchess	Milan, Town of	8/10/1979 (M)
Dutchess	Millbrook, Village of	2/27/1984 (M)
Dutchess	Millerton, Village of	1/3/1985
Dutchess	North East, Town of	9/5/1984
Dutchess	Pawling, Town of	1/3/1985
Dutchess	Pawling, Village of	8/1/1984
Dutchess	Pine Plains, Town of	10/5/1984 (M)
Dutchess	Pleasant Valley, Town of	1/16/1980
Dutchess	Poughkeepsie, City of	1/5/1984
Dutchess	Poughkeepsie, Town of	9/8/1999
Dutchess	Red Hook, Town of	10/16/1984
Dutchess	Red Hook, Village of	(NSFHA)
Dutchess	Rhinebeck, Town of	9/5/1984

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Dutchess	Rhinebeck, Village of	2/1/1985
Dutchess	Stanford, Town of	12/17/1991
Dutchess	Tivoli, Village of	8/1/1984
Dutchess	Union Vale, Town of	9/2/1988
Dutchess	Wappinger, Town of	9/22/1999
Dutchess	Wappingers Falls, Village of	9/22/1999
Dutchess	Washington, Town of	8/17/1979 (M)
Erie	Akron, Village of	11/19/1980
Erie	Alden, Town of	2/6/1991
Erie	Alden, Village of	1/6/1984 (M)
Erie	Amherst, Town of	10/16/1992
Erie	Angola, Village of	8/6/2002
Erie	Aurora, Town of	4/16/1979
Erie	Blasdell, Village of	6/25/1976 (M)
Erie	Boston, Town of	9/30/1981
Erie	Brant, Town of	1/6/1984 (M)
Erie	Buffalo, City of	9/26/2008
Erie	Cheektowaga, Town of	3/15/1984
Erie	Clarence, Town of	3/5/1996
Erie	Colden, Town of	7/2/1979
Erie	Collins,Town of	9/26/2008
Erie	Concord, Town of	9/4/1986
Erie	Depew, Village of	8/3/1981
Erie	East Aurora, Village of	8/6/2002
Erie	Eden, Town of	8/24/1979 (M)
Erie	Elma,Town of	6/22/1998
Erie	Evans, Town of	2/2/2002
Erie	Farnham, Village of	(NSFHA)
Erie	Grand Island, Town of	9/26/2008
Erie	Hamburg, Town of	12/20/2001
Erie	Hamburg, Village of	1/20/1982
Erie	Holland, Town of	9/26/2008
Erie	Kenmore,Village of	(NSFHA)
Erie	Lackawanna, City of	7/2/1980
Erie	Lancaster, Town of	2/23/2001
Erie	Lancaster, Village of	7/2/1979
Erie	Marilla, Town of	9/29/1978
Erie	Newstead, Town of	5/4/1992
Erie	Orchard Park, Town of	3/16/1983
Erie	Orchard Park, Village of	(NSFHA)
Erie	Sardinia, Town of	1/16/2003
Erie	Sloan, Village of	(NSFHA)
Erie	Springville, Village of	7/17/1986
Erie	Tonawanda, City of	9/26/2008
Erie	Tonawanda, Town of	11/12/1982
Erie	Wales, Town of	9/26/2008
Erie	West Seneca, Town of	9/30/1992
Erie	Williamsville, Village of	9/26/2008
Erie/Cattaraugus	Gowanda, Village of	9/26/2008
Essex	Chesterfield, Town of	5/4/1987
Essex	Crown Point,Town of	7/16/1987

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Essex	Elizabethtown, Town of	1/20/1993
Essex	Essex, Town of	4/3/1987
Essex	Jay, Town of	6/17/2002
Essex	Keene, Town of	6/5/1985 (M)
Essex	Keeseville, Village of	9/28/2007 (M)
Essex	Lake Placid, Village of	(NSFHA)
Essex	Lewis, Town of	5/15/1985 (M)
Essex	Minerva, Town of	10/5/1984 (M)
Essex	Moriah, Town of	9/24/1984 (M)
Essex	Newcomb, Town of	6/5/1985 (M)
Essex	North Elba, Town of	8/23/2001
Essex	North Hudson, Town of	5/15/1985 (M)
Essex	Port Henry, Village of	7/16/1987
Essex	Schroon, Town of	11/16/1995
Essex	St. Armand, Town of	2/5/1986
Essex	Ticonderoga, Town of	9/6/1996
Essex	Westport, Town of	9/4/1987
Essex	Willsboro, Town of	5/18/1992
Essex	Wilmington, Town of	11/16/1995
Franklin	Bangor, Town of	(NSFHA)
Franklin	Bellmont, Town of	8/5/1985 (M)
Franklin	Bombay, Town of	2/15/1985 (M)
Franklin	Brandon, Town of	(NSFHA)
Franklin	Brighton, Town of	(NSFHA)
Franklin	Brushton, Village of	2/19/1986 (M)
Franklin	Burke, Town of	2/19/1986 (M)
Franklin	Burke, Village of	(NSFHA)
Franklin	Chateaugay, Village of	(NSFHA)
Franklin	Constable, Town of	(NSFHA)
Franklin	Dickinson, Town of	3/18/1986 (M)
Franklin	Duane, Town of	(NSFHA)
Franklin	Fort Covington, Town of	12/23/1983 (M)
Franklin	Franklin, Town of	9/24/1984 (M)
Franklin	Harrietstown, Town of	1/3/1985
Franklin	Malone, Town of	9/4/1985 (M)
Franklin	Malone, Village of	4/3/1978
Franklin	Moira, Town of	4/15/1986 (M)
Franklin	Santa Clara, Town of	(NSFHA)
Franklin	Saranac Lake, Village of	1/2/1992
Franklin	Tupper Lake, Town of	(NSFHA)
Franklin	Tupper Lake,Village of	3/1/1987 (L)
Franklin	Waverly, Town of	(NSFHA)
Franklin	Westville, Town of	2/15/1985 (M)
Fulton	Bleecker,Town of	7/18/1985 (M)
Fulton	Broadalbin, Town of	1/3/1985 (M)
Fulton	Broadalbin, Village of	4/15/1986 (M)
Fulton	Caroga, Town of	7/18/1985 (M)
Fulton	Ephratah, Town of	7/3/1985 (M)
Fulton	Gloversville, City of	9/30/1983
Fulton	Johnstown, City of	7/18/1983
Fulton	Johnstown, Town of	7/3/1985 (M)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Fulton	Mayfield, Town of	8/5/1985 (M)
Fulton	Northampton, Town of	8/19/1985 (M)
Fulton	Northville, Village of	(NSFHA)
Fulton	Oppenheim, Town of	6/18/1976 (X)
Fulton	Perth, Town of	2/15/1985 (M)
Fulton	Stratford, Town of	1/3/1985 (M)
Genesee	Alabama, Town of	11/18/1983 (M)
Genesee	Alexander, Village of	5/4/1987
Genesee	Alexander,Town of	5/4/1987
Genesee	Batavia, City of	9/16/1982
Genesee	Batavia, Town of	1/17/1985
Genesee	Bergen, Town of	7/6/1984 (M)
Genesee	Bergen, Village of	6/8/1979 (M)
Genesee	Bethany, Town of	9/24/1984 (M)
Genesee	Byron, Town of	2/1/1988 (L)
Genesee	Corfu, Village of	10/15/1985 (M)
Genesee	Darien, Town of	7/6/1984 (M)
Genesee	Elba, Town of	10/5/1984 (M)
Genesee	Elba, Village of	1/20/1984 (M)
Genesee	Le Roy, Town of	9/14/1979 (M)
Genesee	Le Roy, Village of	8/3/1981
Genesee	Oakfield, Town of	5/25/1984 (M)
Genesee	Oakfield, Village of	3/23/1984 (M)
Genesee	Pavilion, Town of	2/27/1984 (M)
Genesee	Pembroke, Town of	1/20/1984 (M)
Genesee	Stafford,Town of	7/16/1982
Genesee/Wyoming	Attica, Village of	7/3/1986
Greene	Ashland, Town of	5/16/2008
Greene	Athens, Town of	5/16/2008
Greene	Athens, Village of	5/16/2008
Greene	Cairo, Town of	5/16/2008
Greene	Catskill, Town of	5/16/2008
Greene	Catskill, Village of	5/16/2008
Greene	Coxsackie, Town of	5/16/2008
Greene	Coxsackie, Village of	5/16/2008
Greene	Durham, Town of	5/16/2008 (M)
Greene	Greenville, Town of	5/16/2008 (M)
Greene	Halcott, Town of	5/16/2008 (M)
Greene	Hunter, Town of	5/16/2008
Greene	Hunter, Village of	5/16/2008
Greene	Jewett, Town of	5/16/2008
Greene	Lexington, Town of	5/16/2008
Greene	New Baltimore, Town of	5/16/2008 (M)
Greene	Prattsville, Town of	5/16/2008
Greene	Tannersville, Village of	5/16/2008
Greene	Windham, Town of	5/16/2008
Hamilton	Arietta, Town of	(NSFHA)
Hamilton	Benson, Town of	(NSFHA)
Hamilton	Hope, Town of	4/30/1986 (M)
Hamilton	Indian Lake, Town of	12/4/1985 (M)
Hamilton	Inlet, Town of	(NSFHA)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Hamilton	Lake Pleasant, Town of	(NSFHA)
Hamilton	Long Lake, Town of	9/24/1984 (M)
Hamilton	Morehouse, Town of	(NSFHA)
Hamilton	Speculator, Village of	2/6/1984 (M)
Hamilton	Wells, Town of	6/3/1986 (M)
Herkimer	Cold Brook, Village of	12/20/2000
Herkimer	Columbia, Town of	7/16/1982 (M)
Herkimer	Danube, Town of	5/12/1999 (M)
Herkimer	Dolgeville, Village of	3/16/1983
Herkimer	Fairfield, Town of	10/18/1988
Herkimer	Frankfort, Town of	12/20/2000
Herkimer	Frankfort, Village of	3/7/2001
Herkimer	German Flatts, Town of	5/15/1985 (M)
Herkimer	Herkimer, Town of	4/17/1985 (M)
Herkimer	Herkimer, Village of	6/17/2002
Herkimer	Ilion, Village of	9/8/1999
Herkimer	Litchfield, Town of	5/7/2001
Herkimer	Little Falls, City of	4/4/1983
Herkimer	Little Falls, Town of	3/28/1980 (M)
Herkimer	Manheim, Town of	5/1/1985 (M)
Herkimer	Middleville, Village of	7/3/1985 (M)
Herkimer	Mohawk, Village of	9/8/1999
Herkimer	Newport, Town of	6/2/1999
Herkimer	Newport, Village of	4/2/1991
Herkimer	Norway, Town of	7/3/1985 (M)
Herkimer	Ohio, Town of	9/24/1984 (M)
Herkimer	Poland, Village of	6/2/1999 (M)
Herkimer	Russia, Town of	6/2/1999
Herkimer	Salisbury, Town of	7/3/1985 (M)
Herkimer	Schuyler, Town of	6/20/2001
Herkimer	Stark, Town of	5/15/1985 (M)
Herkimer	Warren, Town of	(NSFHA)
Herkimer	Webb, Town of	7/30/1982 (M)
Herkimer	West Winfield, Village of	7/3/1985 (M)
Herkimer	Winfield, Town of	7/3/1985 (M)
Jefferson	Adams, Town of	6/5/1985 (M)
Jefferson	Adams, Village of	6/19/1985 (M)
Jefferson	Alexandria Bay, Village of	4/3/1978
Jefferson	Alexandria, Town of	10/15/1985 (M)
Jefferson	Antwerp, Town of	4/15/1986 (M)
Jefferson	Antwerp, Village of	(NSFHA)
Jefferson	Black River, Village of	6/5/1989 (M)
Jefferson	Brownville, Town of	6/2/1992
Jefferson	Brownville, Village of	3/18/1986 (M)
Jefferson	Cape Vincent, Town of	6/2/1992
Jefferson	Cape Vincent, Village of	4/17/1985 (M)
Jefferson	Carthage, Village of	6/17/1991
Jefferson	Champion, Town of	6/2/1993
Jefferson	Chaumont, Village of	9/8/1999
Jefferson	Clayton, Town of	4/2/1986
Jefferson	Clayton, Village of	12/1/1977

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Jefferson	Deferiet, Village of	(NSFHA)
Jefferson	Dexter, Village of	6/15/1994
Jefferson	Ellisburg, Town of	5/18/1992
Jefferson	Ellisburg, Village of	6/19/1985 (M)
Jefferson	Evans Mills, Village of	1/2/1992
Jefferson	Glen Park, Village of	(NSFHA)
Jefferson	Henderson, Town of	5/18/1992
Jefferson	Herrings, Village of	12/18/1985
Jefferson	Hounsfield, Town of	5/18/1992
Jefferson	Leray, Town of	2/2/2002
Jefferson	Lyme, Town of	9/2/1993
Jefferson	Orleans, Town of	3/1/1978
Jefferson	Pamelia, Town of	1/2/1992
Jefferson	Philadelphia, Town of	6/5/1989 (M)
Jefferson	Philadelphia, Village of	9/15/1993
Jefferson	Rodman, Town of	7/3/1985 (M)
Jefferson	Rutland, Town of	8/18/1992
Jefferson	Sackets Harbor, Village of	5/2/1994
Jefferson	Theresa, Town of	10/15/1985 (M)
Jefferson	Theresa, Village of	10/15/1985 (M)
Jefferson	Watertown, City of	8/2/1993
Jefferson	Watertown, Town of	8/2/1993
Jefferson	West Carthage, Village of	9/28/1990
Jefferson	Wilna, Town of	1/16/1992
Jefferson	Worth, Town of	(NSFHA)
Lewis	Castorland, Village of	(NSFHA)
Lewis	Constableville, Village of	7/16/1982 (M)
Lewis	Copenhagen, Village of	(NSFHA)
Lewis	Crogham, Village of	5/15/1985 (M)
Lewis	Croghan, Town of	5/15/1985 (M)
Lewis	Denmark, Town of	5/15/1985 (M)
Lewis	Diana, Town of	9/24/1984 (M)
Lewis	Greig, Town of	5/15/1985 (M)
Lewis	Harrisburg, Town of	(NSFHA)
Lewis	Harrisville, Village of	9/24/1984 (M)
Lewis	Lewis, Town of	9/29/1996
Lewis	Leyden, Town of	6/19/1985 (M)
Lewis	Lowville, Town of	6/20/2000
Lewis	Lowville, Village of	6/20/2000
Lewis	Lyons Falls, Village of	6/19/1985 (M)
Lewis	Lyonsdale, Town of	6/19/1985 (M)
Lewis	Martinsburg, Town of	6/19/1985 (M)
Lewis	New Bremen, Town of	5/4/2000
Lewis	Osceola, Town of	6/30/1976 (M)
Lewis	Pinckney, Town of	(NSFHA)
Lewis	Port Leyden, Village of	6/19/1985 (M)
Lewis	Turin, Town of	8/2/1994
Lewis	Turin, Village of	7/1/1977 (M)
Lewis	Watson, Town of	7/19/2000
Lewis	West Turin, Town of	(NSFHA)
Livingston	Avon, Town of	8/15/1978

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Livingston	Avon, Village of	8/1/1978
Livingston	Caledonia, Town of	6/1/1981
Livingston	Caledonia, Village of	6/1/1981
Livingston	Conesus, Town of	2/15/1991
Livingston	Dansville, Village of	11/1/1978
Livingston	Geneseo, Town of	9/29/1996
Livingston	Geneseo, Village of	9/29/1996
Livingston	Groveland, Town of	2/15/1991
Livingston	Leicester, Town of	1/20/1982
Livingston	Leicester, Village of	8/27/1982 (M)
Livingston	Lima, Town of	12/23/1983 (M)
Livingston	Lima, Village of	7/23/1982 (M)
Livingston	Livonia, Town of	2/19/1992
Livingston	Livonia, Village of	6/1/1988 (L)
Livingston	Mount Morris, Town of	(NSFHA)
Livingston	Mount Morris, Village of	8/1/1978
Livingston	North Dansville, Town of	12/4/1979
Livingston	Nunda, Town of	7/3/1985 (M)
Livingston	Nunda, Village of	3/23/1984 (M)
Livingston	Ossian, Town of	6/8/1984 (M)
Livingston	Portage,Town of	12/18/1984
Livingston	Sparta, Town of	8/27/1982 (M)
Livingston	Springwater, Town of	8/24/1984 (M)
Livingston	West Sparta, Town of	7/18/1985
Livingston	York, Town of	1/20/1982
Madison	Brookfield, Town of	4/17/1985 (M)
Madison	Canastota , Village of	4/15/1988
Madison	Cazenovia, Town of	6/19/1985
Madison	Cazenovia, Village of	6/19/1985
Madison	Chittenango, Village of	2/1/1985 (M)
Madison	De Ruyter, Town of	6/8/1984
Madison	De Ruyter, Village of	8/24/1984 (M)
Madison	Eaton, Town of	9/10/1984 (M)
Madison	Fenner, Township of	2/5/1986
Madison	Georgetown, Town of	11/2/1984 (M)
Madison	Hamilton, Town of	9/27/2002
Madison	Hamilton,Village	9/27/2002
Madison	Lebanon, Town of	4/17/1985 (M)
Madison	Lenox, Town of	6/3/1988
Madison	Lincoln, Town of	9/4/1985 (M)
Madison	Madison, Town of	1/19/1983
Madison	Morrisville, Village of	4/15/1982
Madison	Munnsville, Village of	9/15/1983
Madison	Nelson, Town of	10/5/1984 (M)
Madison	Oneida, City of	2/23/2001
Madison	Smithfield, Town of	4/17/1985 (M)
Madison	Stockbridge, Town of	(NSFHA)
Madison	Sullivan, Town of	5/15/1986
Madison	Wampsville, Village of	(NSFHA)
Monroe	Brighton, Town of	8/28/2008
Monroe	Brockport, Village of	8/28/2008 (M)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Monroe	Chili, Town of	8/28/2008
Monroe	Churchville, Village of	8/28/2008
Monroe	Clarkson, Town of	8/28/2008
Monroe	East Rochester, Village of	8/28/2008 (M)
Monroe	Fairport, Village of	8/28/2008
Monroe	Gates, Town of	8/28/2008
Monroe	Greece, Town of	8/28/2008
Monroe	Hamlin, Town of	8/28/2008
Monroe	Henrietta, Town of	8/28/2008
Monroe	Hilton, Village of	8/28/2008
Monroe	Honeoye Falls, Village of	8/28/2008
Monroe	Irondequoit, Town of	8/28/2008
Monroe	Mendon, Town of	8/28/2008
Monroe	Ogden, Town of	8/28/2008
Monroe	Parma, Town of	8/28/2008
Monroe	Penfield, Town of	8/28/2008
Monroe	Perinton, Town of	8/28/2008
Monroe	Pittsford, Town of	8/28/2008
Monroe	Pittsford, Village of	8/28/2008 (M)
Monroe	Riga, Town of	8/28/2008
Monroe	Rochester, City of	8/28/2008
Monroe	Rush, Town of	8/28/2008
Monroe	Scottsville, Village of	8/28/2008
Monroe	Spencerport, Village of	8/28/2008
Monroe	Sweden, Town of	8/28/2008 (M)
Monroe	Webster, Town of	8/28/2008
Monroe	Webster, Village of	8/28/2008
Monroe	Wheatland, Town of	8/28/2008
Montgomery	Ames, Village of	12/4/1985 (S)
Montgomery	Amsterdam, City of	6/19/1985
Montgomery	Amsterdam, Town of	12/1/1987 (L)
Montgomery	Canajoharie, Town of	1/6/1983
Montgomery	Canajoharie, Village of	11/3/1982
Montgomery	Charleston, Town of	10/15/1985 (M)
Montgomery	Florida, Town of	12/1/1987 (L)
Montgomery	Fonda, Village of	7/6/1983
Montgomery	Fort Johnson, Village of	1/19/1983
Montgomery	Fort Plain, Village of	6/17/2002
Montgomery	Fultonville, Village of	10/15/1982
Montgomery	Glen, Town of	2/19/1986 (M)
Montgomery	Hagaman, Village of	3/18/1986 (M)
Montgomery	Minden, Town of	1/19/1983
Montgomery	Mohawk, Town of	8/5/1985 (M)
Montgomery	Nelliston, Village of	11/3/1982 (S)
Montgomery	Palatine Bridge, Village of	11/17/1982
Montgomery	Palatine, Town of	5/4/1987
Montgomery	Root, Town of	4/1/1988 (L)
Montgomery	St. Johnsville, City of	9/29/1989
Montgomery	St. Johnsville, Town of	3/16/1983
Nassau	Atlantic Beach, Village of	9/11/2009 (>)
Nassau	Baxter Estates, Village of	9/11/2009 (>)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Nassau	Bayville, Village of	9/11/2009 (>)
Nassau	Cedarhurst, Village of	7/20/1998
Nassau	Centre Island, Village of	9/11/2009 (>)
Nassau	Cove Neck, Village of	9/11/2009 (>)
Nassau	East Hills, Village of	(NSFHA)
Nassau	East Rockaway, Village of	9/11/2009 (>)
Nassau	East Williston, Village of	(NSFHA)
Nassau	Floral Park, Village of	(NSFHA)
Nassau	Flower Hill, Village of	9/11/2009 (>)
Nassau	Freeport, Village of	9/11/2009 (>)
Nassau	Garden City, Village of	(NSFHA)
Nassau	Glen Cove, City of	9/11/2009 (>)
Nassau	Great Neck Estates, Village of	9/11/2009 (>)
Nassau	Great Neck Plaza, Village of	9/11/2009 (>)
Nassau	Great Neck, Village of	9/11/2009 (>)
Nassau	Hempstead, Town of	9/11/2009 (>)
Nassau	Hempstead, Village of	(NSFHA)
Nassau	Hewlett Bay Park, Village of	9/11/2009 (>)
Nassau	Hewlett Harbor, Village of	9/11/2009 (>)
Nassau	Hewlett Neck, Village of	9/11/2009 (>)
Nassau	Island Park, Village of	9/11/2009 (>)
Nassau	Kensington, Village of	9/11/2009 (>)
Nassau	Kings Point, Village of	9/11/2009 (>)
Nassau	Lake Success, Village of	(NSFHA)
Nassau	Lattingtown, Village of	9/11/2009 (>)
Nassau	Laurel Hollow, Village of	9/11/2009 (>)
Nassau	Lawrence, Village of	9/11/2009 (>)
Nassau	Long Beach, City of	9/11/2009 (>)
Nassau	Lynbrook, Village of	9/11/2009 (>)
Nassau	Malverne, Village of	9/11/2009 (>)
Nassau	Manorhaven, Village of	9/11/2009 (>)
Nassau	Massapequa Park, Village of	9/11/2009 (>)
Nassau	Mill Neck, Village of	9/11/2009 (>)
Nassau	Mineola, Village of	(NSFHA)
Nassau	Munsey Park, Village of	(NSFHA)
Nassau	New Hyde Park, Village of	(NSFHA)
Nassau	North Hempstead, Town of	9/11/2009 (>)
Nassau	North Hills, Village of	(NSFHA)
Nassau	Oyster Bay Cove, Village of	9/11/2009 (>)
Nassau	Oyster Bay, Town of	9/11/2009 (>)
Nassau	Plandome Heights, Village of	9/11/2009 (>)
Nassau	Plandome Manor, Village of	9/11/2009 (>)
Nassau	Plandome, Village of	9/11/2009 (>)
Nassau	Port Washington North, Village of	9/11/2009 (>)
Nassau	Rockville Centre, Village of	9/11/2009 (>)
Nassau	Roslyn Estates, Village of	(NSFHA)
Nassau	Roslyn Harbor, Village of	9/11/2009 (>)
Nassau	Roslyn, Village of	9/11/2009 (>)
Nassau	Russell Gardens, Village of	9/11/2009 (>)
Nassau	Saddle Rock, Village of	9/11/2009 (>)
Nassau	Sands Point, Village of	9/11/2009 (>)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Nassau	Sea Cliff, Village of	9/11/2009 (>)
Nassau	Stewart Manor, Village of	(NSFHA)
Nassau	Thomaston, Village of	9/11/2009 (>)
Nassau	Valley Stream, Village of	9/11/2009 (>)
Nassau	Westbury, Village of	(NSFHA)
Nassau	Woodsburgh, Village of	9/11/2009 (>)
Niagara	Barker, Village of	5/1/1984
Niagara	Cambria, Town of	9/30/1983
Niagara	Hartland, Town of	10/7/1983 (M)
Niagara	Lewiston, Town of	6/18/1980
Niagara	Lewiston, Village of	(NSFHA)
Niagara	Lockport, City of	2/4/1981
Niagara	Lockport, Town of	10/4/2002
Niagara	Middleport, Village of	8/1/1983
Niagara	Newfane, Town of	11/18/1981
Niagara	Niagara Falls, City of	9/5/1990
Niagara	Niagara, Town of	6/15/1984
Niagara	North Tonawanda, City of	1/6/1982
Niagara	Pendleton, Town of	1/6/1982
Niagara	Porter, Town of	8/15/1983
Niagara	Royalton, Town of	7/6/1979 (M)
Niagara	Somerset, Town of	2/3/1982
Niagara	Wheatfield, Town of	11/4/1992
Niagara	Wilson, Town of	4/1/1981
Niagara	Wilson, Village of	11/19/1980
Niagara	Youngstown, Village of	6/4/1980
Oneida	Annsville, Town of	4/5/1988
Oneida	Augusta, Town of	5/1/1985 (M)
Oneida	Ava, Town of	2/1/1985 (M)
Oneida	Barneveld, Village of	3/23/1999
Oneida	Boonville, Town of	7/3/1985 (M)
Oneida	Boonville, Village of	4/17/1985 (M)
Oneida	Bridgewater, Town of	(NSFHA)
Oneida	Bridgewater, Village of	4/15/1982
Oneida	Camden, Town of	9/7/1998
Oneida	Camden, Village of	8/16/1988
Oneida	Clayville, Village of	7/5/1983
Oneida	Clinton, Village of	5/1/1985
Oneida	Deerfield, Town of	6/2/1999
Oneida	Florence, Town of	4/17/1985 (M)
Oneida	Floyd, Town of	3/15/1984
Oneida	Forestport, Town of	4/17/1985 (M)
Oneida	Holland Patent, Village of	5/21/2001
Oneida	Kirkland, Town of	4/3/1985
Oneida	Lee, Town of	8/3/1998
Oneida	Marcy, Town of	6/1/1984
Oneida	Marshall, Town of	9/30/1982
Oneida	New Hartford, Town of	4/18/1983
Oneida	New Hartford, Village of	7/5/1983
Oneida	New York Mills, Village of	5/4/2000
Oneida	Oneida Castle, Village of	7/4/1989

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Oneida	Oriskany Falls, Village of	1/19/1983
Oneida	Oriskany, Village of	9/15/1983
Oneida	Paris, Town of	9/15/1983
Oneida	Prospect, Village of	11/20/2000 (S)
Oneida	Remsen, Town of	5/1/1985 (M)
Oneida	Remsen, Village of	9/24/1984 (M)
Oneida	Rome, City of	9/21/1998
Oneida	Sangerfield, Town of	6/5/1985
Oneida	Sherrill, City of	9/15/1983
Oneida	Steuben, Town of	9/24/1984 (M)
Oneida	Sylvan Beach, Village of	6/2/1999
Oneida	Trenton, Town of	9/7/1998
Oneida	Utica, City of	2/1/1984
Oneida	Vernon, Town of	8/16/1988
Oneida	Vernon, Village of	4/15/1988
Oneida	Verona, Town of	10/20/1999
Oneida	Vienna, Town of	10/20/1999
Oneida	Waterville, Village of	8/2/1982
Oneida	Western, Town of	5/4/1989
Oneida	Westmoreland, Town of	3/2/1983
Oneida	Whitesboro, Village of	5/4/2000
Oneida	Whitestown, Town of	5/4/2000
Oneida	Yorkville, Village of	5/4/2000
Onondaga	Baldwinsville, Village of	3/1/1984
Onondaga	Camillus, Town of	5/18/1999
Onondaga	Camillus, Village of	5/18/1999
Onondaga	Cicero, Town of	9/15/1994
Onondaga	Clay, Town of	3/16/1992
Onondaga	Dewitt, Town of	3/1/1979
Onondaga	East Syracuse, Village of	8/3/1981
Onondaga	Elbridge, Town of	8/16/1982
Onondaga	Elbridge, Village of	8/16/1982
Onondaga	Fabius, Town of	4/30/1986 (M)
Onondaga	Fayetteville, Village of	4/17/1985
Onondaga	Geddes, Town of	2/17/1982
Onondaga	Jordan, Village of	8/16/1982
Onondaga	Lafayette, Town of	4/3/1985
Onondaga	Liverpool, Village of	2/4/1981
Onondaga	Lysander, Town of	2/4/1983
Onondaga	Manlius, Town of	9/17/1992
Onondaga	Manlius, Village of	8/1/1984
Onondaga	Marcellus, Town of	8/16/1982
Onondaga	Marcellus, Village of	6/1/1982
Onondaga	Minoa, Village of	9/2/1982
Onondaga	North Syracuse, Village of	(NSFHA)
Onondaga	Onondaga, Town of	6/17/1991
Onondaga	Otisco, Town of	6/3/1986 (M)
Onondaga	Pompey, Town of	10/8/1982
Onondaga	Salina, Town of	8/16/1982
Onondaga	Skaneateles, Town of	6/1/1982
Onondaga	Skaneateles, Village of	2/17/1982

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Onondaga	Solvay, Village of	(NSFHA)
Onondaga	Spafford, Town of	4/30/1986 (M)
Onondaga	Syracuse, City of	5/15/1986
Onondaga	Tully, Town of	4/30/1986 (M)
Onondaga	Tully, Village of	1/19/1983
Onondaga	Van Buren, Town of	3/1/1984
Ontario	Bloomfield, Village of	1/1/1950
Ontario	Bristol, Town of	1/20/1984 (M)
Ontario	Canadice, Town of	5/15/1984
Ontario	Canandaigua, City of	9/24/1982
Ontario	Canandaigua, Town of	3/3/1997
Ontario	Clifton Springs, Village of	7/23/1982 (M)
Ontario	East Bloomfield, Town of	8/15/1983
Ontario	Farmington, Town of	9/30/1983
Ontario	Geneva, City of	4/15/1982
Ontario	Geneva, Town of	2/15/1978
Ontario	Gorham, Town of	12/5/1996
Ontario	Hopewell, Town of	2/27/1984 (M)
Ontario	Manchester, Town of	3/9/1984 (M)
Ontario	Manchester, Village of	1/20/1984 (M)
Ontario	Naples, Town of	6/8/1984 (M)
Ontario	Naples, Village of	9/30/1977
Ontario	Phelps, Town of	12/3/1982 (M)
Ontario	Phelps, Village of	1/20/1984 (M)
Ontario	Richmond, Town of	12/18/1984
Ontario	Seneca, Town of	6/22/1984 (M)
Ontario	Shortsville, Village of	9/24/1984 (M)
Ontario	South Bristol, Town of	5/18/1998
Ontario	Victor, Town of	9/30/1983
Ontario	Victor, Village of	5/17/2004
Ontario	West Bloomfield, Town of	6/1/1978
Orange	Blooming Grove, Town of	11/15/1985
Orange	Chester, Town of	6/4/1996
Orange	Chester, Village of	9/18/1986
Orange	Cornwall On The Hudson, Village of	8/2/1982
Orange	Cornwall, Town of	9/30/1982
Orange	Crawford, Town of	9/30/1982
Orange	Deer Park, Town of	10/20/1999
Orange	Florida, Village of	12/4/1986
Orange	Goshen, Town of	4/30/1986
Orange	Goshen, Village of	4/30/1986
Orange	Greenville, Town of	3/4/1985
Orange	Greenwood Lake, Village of	6/15/1979
Orange	Hamptonburgh, Town of	7/3/1986
Orange	Harriman, Village of	9/1/1983
Orange	Highland Falls, Village of	5/19/1987
Orange	Highlands, Township of	5/19/1987
Orange	Kiryas Joel, Village of	6/14/2002
Orange	Maybrook, Village of	1/1/1950
Orange	Middletown, City of	3/2/1983
Orange	Minisink, Town of	4/3/1985

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Orange	Monroe, Town of	2/23/2001
Orange	Monroe, Village of	1/6/1982
Orange	Montgomery, Town of	10/16/1984
Orange	Montgomery, Village of	10/16/1984
Orange	Mount Hope, Town of	10/5/1984 (M)
Orange	New Windsor, Town of	12/15/1978
Orange	Newburgh, City of	6/5/1985
Orange	Newburgh, Town of	6/5/1985
Orange	Port Jervis, City of	4/2/2002
Orange	South Blooming Grove, Village of	1/1/1950
Orange	Tuxedo Park, Village of	1/1/1950
Orange	Tuxedo, Town of	4/15/1982
Orange	Unionville, Village of	7/6/1984 (M)
Orange	Walden, Village of	8/15/1984
Orange	Wallkill, Town of	9/4/1986
Orange	Warwick, Town of	10/15/1985
Orange	Warwick, Village of	2/17/1988
Orange	Washingtonville, Village of	4/1/1981
Orange	Wawayanda, Town of	3/4/1985
Orange	Woodbury, Village of	3/18/1987
Orleans	Albion, Town of	8/8/1980 (M)
Orleans	Albion, Village of	11/30/1979 (M)
Orleans	Barre, Town of	10/15/1981 (M)
Orleans	Carlton, Town of	11/1/1978
Orleans	Clarendon,Town of	(NSFHA)
Orleans	Gaines, Town of	6/8/1984 (M)
Orleans	Holley, Village of	11/30/1979 (M)
Orleans	Kendall, Town of	5/1/1978
Orleans	Lyndonville, Village of	9/16/1981
Orleans	Medina, Village of	3/28/1980 (M)
Orleans	Murray, Town of	3/21/1980 (M)
Orleans	Ridgeway,Town of	9/14/1979 (M)
Orleans	Shelby,Town of	12/23/1983 (M)
Orleans	Yates, Town of	9/29/1978
Oswego	Albion, Town of	4/15/1986 (M)
Oswego	Altmar, Village of	2/5/1986 (M)
Oswego	Amboy, Town of	3/1/1988 (L)
Oswego	Boylston, Town of	(NSFHA)
Oswego	Central Square,Village of	(NSFHA)
Oswego	Cleveland, Village of	6/1/1982
Oswego	Constantia, Town of	11/3/1982
Oswego	Fulton, City of	4/15/1982
Oswego	Granby, Town of	9/16/1982
Oswego	Hannibal, Town of	2/1/1988 (L)
Oswego	Hannibal, Village of	4/1/1987 (L)
Oswego	Hastings, Town of	1/19/1983
Oswego	Lacona, Village of	5/11/1979 (M)
Oswego	Mexico, Town of	10/15/1981
Oswego	Mexico, Village of	10/15/1981
Oswego	Minetto, Town of	9/30/1981
Oswego	New Haven, Town of	11/2/1995

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Oswego	Orwell, Town of	2/19/1986 (S)
Oswego	Oswego, City of	11/22/1999
Oswego	Oswego, Town of	6/20/2001
Oswego	Palermo, Town of	3/1/1988 (S)
Oswego	Parish, Town of	4/15/1986 (M)
Oswego	Parish, Village of	2/19/1986 (M)
Oswego	Phoenix, Village of	2/17/1982
Oswego	Pulaski, Village of	9/2/1982
Oswego	Redfield, Town of	4/1/1991 (L)
Oswego	Richland, Town of	7/17/1995
Oswego	Sandy Creek, Town of	7/17/1995
Oswego	Sandy Creek, Village of	5/11/1979 (M)
Oswego	Schroeppel, Town of	8/2/1982
Oswego	Scriba, Town of	6/6/2001
Oswego	Volney, Town of	4/15/1982
Oswego	West Monroe, Town of	1/20/1982
Oswego	Williamstown, Town of	3/1/1988 (S)
Otsego	Burlington, Town of	10/21/1983 (M)
Otsego	Butternuts, Town of	12/23/1983 (M)
Otsego	Cherry Valley, Town of	2/1/1988 (L)
Otsego	Cherry Valley, Village of	1/3/1986 (M)
Otsego	Cooperstown, Village of	5/4/2000
Otsego	Decatur, Town of	6/18/1987
Otsego	Edmeston, Town of	6/1/1987 (L)
Otsego	Exeter, Town of	11/18/1983 (M)
Otsego	Gilbertsville, Village of	11/1/1985 (M)
Otsego	Hartwick, Town of	11/4/1983 (M)
Otsego	Laurens, Town of	5/15/1985 (M)
Otsego	Laurens, Village of	4/17/1987 (M)
Otsego	Maryland, Town of	6/3/1986 (M)
Otsego	Middlefield, Town of	6/1/1988 (L)
Otsego	Milford, Town of	5/19/1987 (M)
Otsego	Milford, Village of	11/18/1983 (S)
Otsego	Morris, Town of	1/3/1986 (M)
Otsego	Morris, Village of	12/4/1985 (M)
Otsego	New Lisbon, Town of	11/18/1983 (M)
Otsego	Oneonta, City of	9/29/1978
Otsego	Oneonta, Town of	10/17/1986
Otsego	Otego, Town of	2/4/1987
Otsego	Otego, Village of	11/5/1986
Otsego	Otsego, Town of	6/1/1987 (L)
Otsego	Pittsfield, Town of	11/4/1983 (M)
Otsego	Plainfield, Town of	11/4/1983 (M)
Otsego	Richfield Springs, Village of	1/3/1986 (M)
Otsego	Richfield, Town of	4/15/1986 (M)
Otsego	Roseboom, Town of	6/1/1988 (S)
Otsego	Springfield, Town of	6/1/1987 (L)
Otsego	Unadilla, Town of	9/30/1987
Otsego	Unadilla, Village of	9/30/1987
Otsego	Westford, Town of	6/1/1988 (L)
Otsego	Worcester, Town of	6/1/1988 (L)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Putnam	Brewster, Village of	9/18/1986
Putnam	Carmel,Town of	10/19/2001
Putnam	Cold Spring, Village of	3/15/1984
Putnam	Kent, Town of	9/4/1986
Putnam	Nelsonville, Village of	9/10/1984 (M)
Putnam	Patterson, Town of	7/3/1986
Putnam	Philipstown,Town of	6/18/1987
Putnam	Putnam Valley, Town of	6/20/2001
Putnam	Southeast, Town of	9/4/1986
Rensselaer	Berlin, Town of	8/17/1979 (M)
Rensselaer	Brunswick, Town of	12/6/2000
Rensselaer	Castleton-On-Hudson, Village of	11/15/1984
Rensselaer	East Greenbush, Town of	3/18/1980
Rensselaer	East Nassau, Village of	9/5/1984
Rensselaer	Grafton, Town of	10/13/1978 (M)
Rensselaer	Hoosick Falls, Village of	2/4/2005
Rensselaer	Hoosick, Town of	8/1/1987 (L)
Rensselaer	Nassau, Town of	9/5/1984
Rensselaer	Nassau, Village of	5/18/1979 (M)
Rensselaer	North Greenbush,Town of	6/18/1980
Rensselaer	Petersburg, Town of	9/1/1978 (M)
Rensselaer	Pittstown, Town of	9/5/1990
Rensselaer	Poestenkill, Town of	9/2/1981
Rensselaer	Rensselaer, City of	3/18/1980
Rensselaer	Sand Lake, Town of	5/15/1980
Rensselaer	Schaghticoke, Town of	7/16/1984
Rensselaer	Schaghticoke, Village of	6/5/1985
Rensselaer	Schodack, Town of	8/15/1984
Rensselaer	Stephentown, Town of	8/3/1981
Rensselaer	Troy, City of	3/18/1980
Rensselaer	Valley Falls, Village of	6/5/1985
Richmond/Queens/ New York/Kings/Bronx	New York, City of	9/5/2007
Rockland	Chestnut Ridge, Village of	9/16/1988
Rockland	Clarkstown, Town of	5/21/2001
Rockland	Grand View-On-Hudson, Village of	10/15/1981
Rockland	Haverstraw, Town of	1/6/1982
Rockland	Haverstraw, Village of	9/2/1981
Rockland	Hillburn, Village of	9/20/1996
Rockland	Kaser, Village of	1/1/1950
Rockland	Montebello, Village of	1/18/1989
Rockland	New Hempstead, Village of	12/16/1988
Rockland	New Square, Village of	(NSFHA)
Rockland	Nyack, Village of	12/4/1985
Rockland	Orangetown, Town of	8/2/1982
Rockland	Piermont, Village of	11/17/1982
Rockland	Pomona, Village of	4/15/1982
Rockland	Ramapo, Town of	2/2/1989
Rockland	Sloatsburg, Village of	1/6/1982
Rockland	South Nyack, Village of	11/4/1981
Rockland	Spring Valley, Village of	8/16/1988

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Rockland	Stony Point, Town of	9/30/1981
Rockland	Suffern, Village of	3/28/1980
Rockland	Upper Nyack, Village of	(NSFHA)
Rockland	Wesley Hills, Village of	9/16/1988
Rockland	West Haverstraw, Village of	9/30/1981
Saratoga	Ballston Spa, Village of	8/16/1995
Saratoga	Ballston, Town of	8/16/1995
Saratoga	Charlton, Town of	8/16/1995
Saratoga	Clifton Park, Town of	8/16/1995
Saratoga	Corinth, Town of	8/16/1995
Saratoga	Corinth, Village of	8/16/1995
Saratoga	Day, Town of	(NSFHA)
Saratoga	Galway, Town of	8/16/1995
Saratoga	Greenfield, Town of	8/16/1995
Saratoga	Hadley, Town of	8/16/1995
Saratoga	Halfmoon, Town of	8/16/1995
Saratoga	Malta, Town of	8/16/1995
Saratoga	Mechanicville, City of	8/16/1995
Saratoga	Milton, Town of	8/16/1995
Saratoga	Moreau, Town of	8/16/1995
Saratoga	Northumberland, Town of	8/16/1995
Saratoga	Providence, Town of	8/16/1995
Saratoga	Round Lake, Village of	8/16/1995
Saratoga	Saratoga Springs, City of	8/16/1995
Saratoga	Saratoga, Town of	8/16/1995
Saratoga	Schuylerville, Village of	8/16/1995
Saratoga	South Glens Falls, Village of	8/16/1995
Saratoga	Stillwater, Town of	8/16/1995
Saratoga	Stillwater, Village of	8/16/1995
Saratoga	Victory, Village of	8/16/1995
Saratoga	Waterford, Town of	8/16/1995
Saratoga	Waterford, Village of	8/16/1995
Saratoga	Wilton,Town of	(NSFHA)
Schenectady	Delanson, Village of	5/25/1984 (M)
Schenectady	Duanesburg, Town of	2/17/1989
Schenectady	Glenville,Town of	5/4/1987
Schenectady	Niskayuna, Town of	3/1/1978
Schenectady	Princetown, Town of	7/1/1988 (L)
Schenectady	Rotterdam, Town of	6/15/1984
Schenectady	Schenectady, City of	9/30/1983
Schenectady	Scotia, Village of	6/1/1984
Schoharie	Blenheim, Town of	4/2/2004
Schoharie	Broome, Town of	4/2/2004
Schoharie	Carlisle, Town of	4/2/2004
Schoharie	Cobleskill, Town of	4/2/2004
Schoharie	Cobleskill, Village of	4/2/2004
Schoharie	Conesville, Town of	4/2/2004
Schoharie	Esperance, Town of	4/2/2004
Schoharie	Esperance, Village of	4/2/2004
Schoharie	Fulton, Town of	4/2/2004
Schoharie	Gilboa, Town of	4/2/2004

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Schoharie	Jefferson, Town of	4/2/2004
Schoharie	Middleburgh, Town of	4/2/2004
Schoharie	Middleburgh, Village of	4/2/2004
Schoharie	Richmondville, Town of	4/2/2004
Schoharie	Richmondville, Village of	4/2/2004
Schoharie	Schoharie, Town of	4/2/2004
Schoharie	Schoharie, Village of	4/2/2004
Schoharie	Seward, Town of	4/2/2004
Schoharie	Sharon Spring, Village of	4/2/2004 (M)
Schoharie	Sharon, Town of	4/2/2004
Schoharie	Summit, Town of	4/2/2004
Schoharie	Wright, Town of	4/2/2004
Schuyler	Burdett, Village of	6/1/1988 (L)
Schuyler	Catharine, Town of	4/20/1984 (M)
Schuyler	Cayuta, Town of	9/24/1984 (M)
Schuyler	Dix, Town of	10/29/1982 (M)
Schuyler	Hector, Town of	7/20/1984 (M)
Schuyler	Montour Falls, Village of	9/15/1983
Schuyler	Montour, Town of	3/1/1988 (L)
Schuyler	Odessa, Village of	4/20/1984 (M)
Schuyler	Orange, Town of	4/20/1984 (M)
Schuyler	Reading, Town of	(NSFHA)
Schuyler	Tyrone, Town of	7/6/1984 (M)
Schuyler	Watkins Glen, Village of	7/17/1978
Seneca	Covert, Town of	6/8/1984 (M)
Seneca	Fayette, Town of	1/15/1988
Seneca	Lodi, Town of	1/15/1988
Seneca	Lodi, Village of	(NSFHA)
Seneca	Ovid, Town of	1/15/1988
Seneca	Romulus, Town of	6/5/1985 (M)
Seneca	Seneca Falls, Town of	8/3/1981
Seneca	Seneca Falls, Village of	8/3/1981
Seneca	Tyre, Town of	8/31/1979 (M)
Seneca	Varick, Town of	12/17/1987
Seneca	Waterloo, Town of	9/16/1981
Seneca	Waterloo, Village of	8/3/1981
St. Lawrence	Brasher, Town of	1/3/1986 (M)
St. Lawrence	Canton, Town of	8/17/1998
St. Lawrence	Canton, Village of	5/2/1994
St. Lawrence	Clare, Town of	7/16/1982 (M)
St. Lawrence	Clifton, City of	5/15/1986 (M)
St. Lawrence	Colton, Town of	5/1/1985 (M)
St. Lawrence	De Kalb, Town of	(NSFHA)
St. Lawrence	De Peyster, Town of	7/23/1982 (M)
St. Lawrence	Edwards, Town of	7/30/1982 (M)
St. Lawrence	Edwards, Village of	7/23/1982 (M)
St. Lawrence	Fine, Town of	5/1/1985 (M)
St. Lawrence	Fowler, Town of	6/5/1989 (M)
St. Lawrence	Gouverneur, Town of	8/6/1982 (M)
St. Lawrence	Gouverneur, Village of	3/3/1997
St. Lawrence	Hammond, Town of	(NSFHA)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
St. Lawrence	Hermon, Town of	(NSFHA)
St. Lawrence	Hermon, Village of	8/3/1998
St. Lawrence	Heuvelton, Village of	4/30/1986 (M)
St. Lawrence	Hopkinton, Town of	11/12/1982 (M)
St. Lawrence	Lawrence, Town of	(NSFHA)
St. Lawrence	Lisbon, Town of	(NSFHA)
St. Lawrence	Louisville, Town of	(NSFHA)
St. Lawrence	Macomb, Town of	(NSFHA)
St. Lawrence	Madrid, Town of	(NSFHA)
St. Lawrence	Massena, Town of	6/17/1986 (M)
St. Lawrence	Massena, Village of	11/5/1980
St. Lawrence	Morristown, Town of	8/6/1982 (M)
St. Lawrence	Morristown, Village of	12/2/1980 (M)
St. Lawrence	Norfolk, Town of	4/15/1986 (M)
St. Lawrence	Norwood, Village of	4/30/1986 (M)
St. Lawrence	Ogdensburg, City of	11/5/1980
St. Lawrence	Oswegatchie, Town of	5/1/1985 (M)
St. Lawrence	Parishville, Town of	7/30/1982 (M)
St. Lawrence	Piercefield, Town of	1/6/1984 (M)
St. Lawrence	Pierrepont, Town of	(NSFHA)
St. Lawrence	Pitcairn, Town of	8/13/1982 (M)
St. Lawrence	Potsdam, Village of	1/5/1996
St. Lawrence	Potsdam,Town of	3/4/1986 (M)
St. Lawrence	Rensselaer Falls, Village of	1/6/1984 (M)
St. Lawrence	Richville, Village of	1/6/1984 (M)
St. Lawrence	Rossie, Town of	7/30/1982 (M)
St. Lawrence	Russell, Town of	(NSFHA)
St. Lawrence	Stockholm, Town of	4/15/1986 (M)
St. Lawrence	Waddington, Town of	4/15/1986 (M)
St. Lawrence	Waddington, Village of	5/11/1979 (M)
Steuben	Addison, Town of	12/18/1984
Steuben	Addison, Village of	6/15/1981
Steuben	Arkport, Village of	3/4/1980
Steuben	Avoca, Town of	2/5/1992
Steuben	Avoca, Village of	5/16/1983
Steuben	Bath, Town of	5/2/1983
Steuben	Bath, Village of	3/16/1983
Steuben	Bradford, Town of	9/24/1984 (M)
Steuben	Cameron, Town of	5/15/1991
Steuben	Campbell, Town of	6/11/1982
Steuben	Canisteo, Town of	12/18/1984
Steuben	Canisteo, Village of	5/18/1979 (M)
Steuben	Caton, Town of	3/23/1984 (M)
Steuben	Cohocton, Town of	5/16/1983
Steuben	Cohocton, Village of	5/16/1983
Steuben	Corning, City of	9/27/2002
Steuben	Corning, Town of	9/27/2002
Steuben	Dansville, Town of	3/9/1984 (M)
Steuben	Erwin, Town of	7/2/1980
Steuben	Fremont, Town of	10/29/1982 (M)
Steuben	Greenwood, Town of	9/3/1982 (M)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Steuben	Hammondsport, Village of	4/17/1978
Steuben	Hartsville, Town of	9/17/1982 (M)
Steuben	Hornby, Town of	4/15/1986
Steuben	Hornell, City of	3/18/1980
Steuben	Hornellsville, Town of	7/16/1980
Steuben	Howard, Town of	9/3/1982 (M)
Steuben	Jasper, Town of	7/23/1982 (M)
Steuben	Lindley, Town of	8/1/1980
Steuben	North Hornell, Village of	1/17/1986
Steuben	Painted Post, Village of	5/18/2000
Steuben	Prattsburg, Town of	1/20/1984 (M)
Steuben	Pulteney, Town of	9/30/1977
Steuben	Rathbone, Town of	12/3/1982 (M)
Steuben	Riverside, Village of	5/15/1980
Steuben	Savona, Village of	8/15/1980
Steuben	South Corning, Village of	10/15/1981
Steuben	Thurston, Town of	2/11/1983 (M)
Steuben	Troupsburg, Town of	9/24/1982 (M)
Steuben	Tuscarora, Town of	3/1/1988 (L)
Steuben	Urbana, Town of	1/19/1978
Steuben	Wayland, Town of	6/8/1984 (M)
Steuben	Wayland, Village of	8/1/1988 (L)
Steuben	Wayne, Town of	11/2/1977
Steuben	West Union, Town of	7/1/1988 (L)
Steuben	Wheeler, Town of	7/25/1980 (M)
Steuben	Woodhull, Town of	4/2/1991
Steuben/Allegany	Almond, Town of	3/4/1980
Suffolk	Amityville, Village of	5/4/1998
Suffolk	Asharoken, Village of	5/4/1998
Suffolk	Babylon, Village of	5/4/1998
Suffolk	Babylon,Town of	5/4/1998
Suffolk	Belle Terre, Village of	5/4/1998
Suffolk	Bellport, Village of	5/4/1998
Suffolk	Brightwaters, Village of	5/4/1998
Suffolk	Brookhaven,Town of	5/4/1998
Suffolk	Dering Harbor, Village of	5/4/1998
Suffolk	East Hampton,Town of	5/4/1998
Suffolk	East Hampton,Village of	5/4/1998
Suffolk	Greenport, Village of	5/4/1998
Suffolk	Head of The Harbor, Village of	5/4/1998
Suffolk	Huntington Bay, Village of	5/4/1998
Suffolk	Huntington, Town of	5/4/1998
Suffolk	Islandia, Village of	5/4/1998 (X)
Suffolk	Islip,Town of	5/4/1998
Suffolk	Lake Grove, Village of	(NSFHA)
Suffolk	Lindenhurst, Village of	5/4/1998
Suffolk	Lloyd Harbor, Village of	5/4/1998
Suffolk	Nissequogue, Village of	5/4/1998
Suffolk	North Haven, Village of	5/4/1998
Suffolk	Northport, Village of	5/4/1998
Suffolk	Ocean Beach, Village of	5/4/1998

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Suffolk	Old Field, Village of	5/4/1998
Suffolk	Patchogue, Village of	5/4/1998
Suffolk	Poospatuck Indian Reservation	9/25/2009 (>)(X)
Suffolk	Poquott, Village of	5/4/1998
Suffolk	Port Jefferson, Village of	5/4/1998
Suffolk	Quogue, Village of	5/4/1998
Suffolk	Riverhead, Town of	5/4/1998
Suffolk	Sag Harbor, Village of	5/4/1998
Suffolk	Sagaponack, Village of	5/4/1998
Suffolk	Saltaire,Village of	5/4/1998
Suffolk	Shelter Island, Town of	5/4/1998
Suffolk	Shinnecock Indian Reservation	9/25/2009 (>)(X)
Suffolk	Shoreham, Village of	5/4/1998
Suffolk	Smithtown, Town of	5/4/1998
Suffolk	Southampton, Town of	5/4/1998
Suffolk	Southampton, Village of	5/4/1998
Suffolk	Southold,Town of	5/4/1998
Suffolk	The Branch, Village of	5/4/1998
Suffolk	West Hampton Dunes, Village of	5/4/1998
Suffolk	Westhampton Beach, Village of	5/4/1998
Sullivan	Bethel, Town of	2/27/1984 (M)
Sullivan	Bloomingburg, Village of	4/17/1985
Sullivan	Callicoon, Town of	3/23/1984 (M)
Sullivan	Cochecton, Town of	8/19/1987
Sullivan	Delaware, Town of	1/16/1987
Sullivan	Fallsburg, Town of	3/9/1984 (M)
Sullivan	Forestburgh, Town of	(NSFHA)
Sullivan	Fremont, Town of	4/3/1987
Sullivan	Highland, Town of	3/4/1987
Sullivan	Jeffersonville, Village of	7/16/1990
Sullivan	Liberty, Town of	6/5/1985
Sullivan	Liberty, Village of	2/1/1985
Sullivan	Lumberland, Town of	10/19/2001
Sullivan	Mamakating, Town of	9/30/1992
Sullivan	Monticello, Village of	(NSFHA)
Sullivan	Neversink, Town of	5/25/1984 (M)
Sullivan	Rockland, Town of	6/2/1993
Sullivan	Thompson, Town of	2/15/1991
Sullivan	Tusten, Town of	8/20/2002
Sullivan	Woodridge, Village of	6/25/1976 (M)
Sullivan	Wurtsboro, Village of	2/3/1993
Tioga	Barton, Town of	5/15/1991
Tioga	Berkshire, Town of	5/15/1985 (M)
Tioga	Candor, Town of	8/19/1986
Tioga	Candor, Village of	10/1/1991 (L)
Tioga	Newark Valley, Town of	2/3/1982
Tioga	Newark Valley, Village of	2/3/1982
Tioga	Nichols, Town of	2/17/1982
Tioga	Nichols, Village of	9/29/1986 (S)
Tioga	Owego, Town of	1/17/1997
Tioga	Owego, Village of	4/2/1982

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Tioga	Richford, Town of	5/15/1985 (M)
Tioga	Spencer, Town of	5/15/1985 (M)
Tioga	Spencer, Village of	5/15/1985 (M)
Tioga	Tioga, Town of	5/17/1982
Tioga	Waverly, Village of	3/16/1983
Tompkins	Caroline, Town of	6/19/1985 (M)
Tompkins	Cayuga Heights, Village of	(NSFHA)
Tompkins	Danby, Town of	5/15/1985 (M)
Tompkins	Dryden, Town of	5/15/1985 (M)
Tompkins	Dryden, Village of	1/3/1979
Tompkins	Freeville, Village of	5/1/1988 (L)
Tompkins	Groton, Town of	10/5/1984 (M)
Tompkins	Groton, Village of	11/5/1986
Tompkins	Ithaca, City of	9/30/1981
Tompkins	Ithaca, Town of	6/19/1985
Tompkins	Lansing, Town of	10/15/1985
Tompkins	Lansing, Village of	11/19/1987
Tompkins	Newfield, Town of	10/15/1985 (M)
Tompkins	Trumansburg, Village of	4/1/1988 (L)
Tompkins	Ulysses, Town of	2/19/1987
Ulster	Denning, Town of	5/25/1984 (M)
Ulster	Ellenville, Village of	7/5/1983
Ulster	Esopus, Town of	7/5/1984
Ulster	Gardiner, Town of	7/16/1997
Ulster	Hardenburgh, Town of	3/16/1989
Ulster	Hurley, Town of	8/18/1992
Ulster	Kingston, City of	5/1/1985
Ulster	Kingston,Town of	4/5/1988
Ulster	Lloyd, Town of	7/5/2000
Ulster	Marbletown, Town of	8/5/1991
Ulster	Marlborough, Town of	12/5/1984
Ulster	New Paltz, Town of	11/1/1985
Ulster	New Paltz, Village of	10/15/1985
Ulster	Olive, Town of	11/1/1984
Ulster	Plattekill, Town of	(NSFHA)
Ulster	Rochester, Town of	2/6/1991
Ulster	Rosendale, Town of	11/1/1985
Ulster	Saugerties, Town of	9/30/1992
Ulster	Saugerties, Village of	8/5/1985 (M)
Ulster	Shandaken, Town of	2/17/1989
Ulster	Shawangunk, Town of	9/30/1982
Ulster	Ulster, Town of	5/1/1985
Ulster	Wawarsing, Town of	9/15/1983
Ulster	Woodstock, Town of	9/27/1991
Warren	Bolton, Town of	8/16/1996
Warren	Chester, Town of	6/5/1985 (M)
Warren	Glens Falls, City of	6/5/1985
Warren	Hague, Town of	9/29/1996
Warren	Horicon, Town of	2/15/1985 (M)
Warren	Johnsburg, Town of	5/1/1985 (M)
Warren	Lake George, Town of	8/16/1996

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Warren	Lake George, Village of	9/29/1996
Warren	Lake Luzerne, Town of	5/1/1984
Warren	Queensbury, Town of	8/16/1996
Warren	Stony Creek, Town of	8/24/1984 (M)
Warren	Thurman, Town of	8/19/1986
Warren	Warrensburg, Town of	3/1/1984
Washington	Argyle, Town of	8/24/1979 (M)
Washington	Argyle, Village of	5/18/1979 (M)
Washington	Cambridge, Town of	9/4/1985 (M)
Washington	Cambridge, Village of	1/2/2008
Washington	Dresden, Town of	9/20/1996
Washington	Easton, Town of	11/20/1991
Washington	Fort Ann, Town of	11/5/1997
Washington	Fort Ann, Village of	(NSFHA)
Washington	Fort Edward, Town of	12/15/1982
Washington	Fort Edward, Village of	2/15/1984
Washington	Granville, Town of	8/5/1985 (M)
Washington	Granville, Village of	4/17/1985 (M)
Washington	Greenwich, Village of	5/4/2000
Washington	Greenwich,Town of	3/16/1992
Washington	Hampton, Town of	4/17/1985 (M)
Washington	Hartford, Town of	11/1/1985 (M)
Washington	Hebron, Town of	6/15/1994
Washington	Hudson Falls, Village of	(NSFHA)
Washington	Jackson, Town of	3/16/1992
Washington	Kingsbury, Town of	9/7/1979 (M)
Washington	Putnam, Town of	11/20/1996
Washington	Salem, Village of	4/17/1985 (M)
Washington	Salem,Town of	4/17/1985 (M)
Washington	White Creek, Town of	4/17/1985 (M)
Washington	Whitehall, Town of	7/3/1986
Washington	Whitehall, Village of	6/3/1985 (M)
Wayne	Arcadia, Town of	11/2/1977
Wayne	Butler, Town of	7/9/1982 (M)
Wayne	Clyde, Village of	12/18/1984
Wayne	Galen, Town of	5/16/1983
Wayne	Huron, Town of	1/19/1996
Wayne	Lyons, Town of	9/7/1979 (M)
Wayne	Lyons, Village of	3/16/1983
Wayne	Macedon, Town of	1/5/1984
Wayne	Macedon, Village of	9/30/1983
Wayne	Marion, Town of	7/1/1988 (L)
Wayne	Newark, Village of	7/15/1988
Wayne	Ontario, Town of	6/1/1978
Wayne	Palmyra, Town of	3/1/1978
Wayne	Palmyra, Village of	7/15/1988
Wayne	Red Creek, Village of	4/8/1983 (M)
Wayne	Rose, Town of	3/9/1984 (M)
Wayne	Savannah, Town of	8/6/1982 (M)
Wayne	Sodus Point, Village of	11/2/1977
Wayne	Sodus, Town of	6/2/1992

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Wayne	Walworth, Town of	3/16/1983
Wayne	Williamson Town	10/17/1978
Wayne	Wolcott, Town of	6/2/1992
Wayne	Wolcott, Village of	7/6/1984 (M)
Westchester	Ardsley, Village of	9/28/2007
Westchester	Bedford, Town of	9/28/2007
Westchester	Briarcliff Manor, Village of	9/28/2007
Westchester	Bronxville, Village of	9/28/2007
Westchester	Buchanan, Village of	9/28/2007 (M)
Westchester	Cortlandt, Town of	9/28/2007
Westchester	Croton-On-Hudson, Village of	9/28/2007
Westchester	Dobbs Ferry, Village of	9/28/2007
Westchester	Eastchester, Town of	9/28/2007
Westchester	Elmsford, Village of	9/28/2007
Westchester	Greenburgh,Town of	9/28/2007
Westchester	Harrison, Town of	9/28/2007
Westchester	Hastings-On-Hudson, Village of	9/28/2007
Westchester	Irvington, Village of	9/28/2007
Westchester	Larchmont, Village of	9/28/2007
Westchester	Lewisboro, Town of	9/28/2007 (M)
Westchester	Mamaroneck, Town of	9/28/2007
Westchester	Mamaroneck, Village of	9/28/2007
Westchester	Mount Kisco, Village of	9/28/2007
Westchester	Mount Pleasant, Town of	9/28/2007
Westchester	Mount Vernon, City of	9/28/2007
Westchester	New Castle, Town of	9/28/2007
Westchester	New Rochelle, City of	9/28/2007
Westchester	North Castle, Town of	9/28/2007
Westchester	North Salem, Town of	9/28/2007
Westchester	Ossining, Town of	9/28/2007
Westchester	Ossining, Village of	9/28/2007
Westchester	Peekskill, City of	9/28/2007
Westchester	Pelham Manor, Village of	9/28/2007
Westchester	Pelham, Village of	9/28/2007
Westchester	Pleasantville, Village of	9/28/2007
Westchester	Port Chester, Village of	9/28/2007
Westchester	Pound Ridge, Town of	9/28/2007
Westchester	Rye Brook, Village of	9/28/2007
Westchester	Rye, City of	9/28/2007
Westchester	Scarsdale, Village of	9/28/2007
Westchester	Sleepy Hollow, Village of	9/28/2007
Westchester	Somers, Town of	9/28/2007
Westchester	Tarrytown, Village of	9/28/2007
Westchester	Tuckahoe, Village of	9/28/2007
Westchester	White Plains, City of	9/28/2007
Westchester	Yonkers, City of	9/28/2007
Westchester	Yorktown, Town of	9/28/2007
Wyoming	Arcade, Town of	3/3/1992
Wyoming	Arcade, Village of	3/3/1992
Wyoming	Attica, Town of	4/30/1986
Wyoming	Bennington, Town of	12/23/1983 (M)

TABLE 3.3

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Wyoming	Castile, Town of	12/23/1983 (M)
Wyoming	Castile, Village of	5/28/1982 (M)
Wyoming	Covington, Town of	12/23/1983 (M)
Wyoming	Eagle, Town of	12/23/1983 (M)
Wyoming	Gainesville, Town of	12/23/1983 (M)
Wyoming	Gainesville, Village of	2/15/1985 (M)
Wyoming	Genesee Falls, Town of	5/1/1984
Wyoming	Java, Town of	12/23/1983 (M)
Wyoming	Orangeville, Town of	12/23/1983 (M)
Wyoming	Perry, Town of	12/23/1983 (M)
Wyoming	Perry, Village of	7/29/1977 (M)
Wyoming	Pike, Town of	12/23/1983 (M)
Wyoming	Pike, Village of	6/18/1982 (M)
Wyoming	Sheldon, Town of	12/23/1983 (M)
Wyoming	Silver Springs, Village of	1/20/1984 (M)
Wyoming	Warsaw, Town of	12/23/1983 (M)
Wyoming	Warsaw, Village of	11/18/1981
Wyoming	Wethersfield, Town of	7/16/1982 (S)
Wyoming	Wyoming, Village of	8/3/1981
Yates	Barrington, Town of	3/9/1984 (M)
Yates	Benton, Town of	1/20/1984 (M)
Yates	Dresden, Village of	6/15/1981
Yates	Dundee, Village of	3/1/1988 (L)
Yates	Italy, Town of	3/7/2001
Yates	Jerusalem, Town of	1/20/1984 (M)
Yates	Middlesex, Town of	9/29/1989
Yates	Milo, Town of	7/18/1985 (M)
Yates	Penn Yan, Village of	6/15/1981
Yates	Potter, Town of	3/23/1984 (M)
Yates	Rushville, Village of	6/5/1985 (M)
Yates	Starkey, Town of	12/3/1987
Yates	Torrey, Town of	12/3/1987

Notes:
(NSFHA) - No special flood hazard area - All Zone "C"
(M) No elevation determined - All Zone "A", "C", and "X"
(L) Original FIRM by letter - All Zone "A", "C", and "X"
(S) Suspended community, not in the National Flood Program.
(X) Community not in National Flood Program
(>) Date of current effective map is after the date of this report.
Source: FEMA "Community Status Book Report – July 23, 2009."
(http://www.fema.gov/fema/csb.shtm)

TABLE 4.1
Substances Found in Frac Fluid or Flowback Water

	Substance	NYSDOH MCL (mg/L)	NYSDEC Part 703 Health (Water Source) Standard (mg/L)
	1,1,1-Trifluorotoluene		
95-63-6	1,2,4 Trimethylbenzene	0.005	0.005
7732-18-5	1,2-Benzisothiazolin-2-one		
2634-33-5	1,2-Benzisothiazolin-3-one		
123-91-1	1,4 Dioxane		
	1,4-Dichlorobutane		
3452-07-1	1-Eicosene		
629-73-2	1-Hexadecene		
112-88-9	1-Octadecene		
61789-40-0	1-Propanaminium,3-amino-n-(carboxy methyl)-n,n-dimethyl-n-coco alkyl derivative		
1120-36-1	1-Tetradecene		
27776-21-2	2,2'-Azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride		
10222-01-2	2,2-Dibromo-3-nitrilopropionamide	0.05	
73003-80-2	2,2-Dibromomalonamide	0.05	
	2,4,6-Tribromophenol		
	2,5-Dibromotoluene		
	2-Acrylamido-2-methylpropanesulphonic acid sodium salt polymer		
46830-22-2	2-Acryloyloxyethyl(benzyl)dimethylammonium chloride		
00111-76-2	2-Butoxy ethanol	0.05	
01113-55-9	2-Dibromo-3-nitriloprionamide (a.k.a 2-Monobromo-3-nitrilopropionamide)	0.05	
00104-76-7	2-Ethyl hexanol	0.05	
	2-Fluorobiphenyl		
	2-Fluorophenol		
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-chloride, homopolymer		
9003-03-6	2-Propenoic acid, homopolymer, ammonium salt		
25987-30-8	2-Propenoic acid, polymer with 2 p-propenamide, sodium salt		
71050-62-9	2-Propenoic acid, polymer with sodium phosphinate (1:1)		
66019-18-9	2-Propenoic acid, telomer with sodium hydrogen sulfite		
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride		
00115-19-5	3-Methyl-1-butyn-3-ol	0.05	
00056-57-5	4-Nitroquinoline-1 -oxide		
	4-Terphenyl-d14		
64-19-7	Acetic acid		
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine		
108-24-7	Acetic anhydride		
00067-64-1	Acetone		
00079-06-1	Acrylamide	0.005	
38193-60-1	Acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer		
69418-26-4	Acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy ethanaminium chloride		
15085-02-3	Acrylamide-sodium acrylate copolymer		
126950-60-5	Alcohol ethoxylated		
68439-46-3	Alcohols C9-11, ethoxylated (a.k.a. Ethoxylated alcohol)	0.05	
67254-71-1	Alcohols, C10-12, ethoxylated	0.05	
84133-50-6	Alcohols, C12-14-secondary, ethoxylated	0.05	

TABLE 4.1
Substances Found in Frac Fluid or Flowback Water

CAS Number	Substance	NYSDOH MCL (mg/L)	NYSDEC Part 703 Health (Water Source) Standard (mg/L)
68551-12-2	Alcohols, C12-C16, ethoxylated (a.k.a. Ethoxylated alcohol)	0.05	
68951-67-7	Alcohols, C14-15, ethoxylated	0.05	
64742-47-8	Aliphatic hydrocarbon (a.k.a. hydrotreated light distillate)		
64743-02-8	Alkenes, C>10 α-		
	Alkyl aryl polyethoxy ethanol		
07439-90-5	Aluminum		
1327-41-9	Aluminum chloride, basic		
73138-27-9	Amines, C12-14-tert-alkyl, ethoxylated		
71011-04-6	Amines, Ditallow alkyl, ethoxylated		
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates		
07664-41-7	Ammonia/ammonium		2
631-61-8	Ammonium acetate		
68037-05-8	Ammonium alcohol ether sulfate		
63428-86-4	Ammonium alcohol ether sulfate		
07783-20-2	Ammonium bisulfate		
12125-02-9	Ammonium chloride		
	Ammonium citrate		
37475-88-0	Ammonium cumene sulfonate		
1341-49-7	Ammonium hydrogen-difluoride (NH_4HF_2)		
06484-52-2	Ammonium nitrate		
7757-54-0	Ammonium persulfate		
1762-95-4	Ammonium thiocyanate		
112945-52-5	Amorphous Silica (a.k.a Pyrogenic Silica)		
25085-02-3	Anionic polyacrylamide (a.k.a Sodium acrylate-acrylamide copolymer)		
07440-36-0	Antimony	0.006	0.003
07440-38-2	Arsenic	0.01	0.05
07440-39-3	Barium	2	1
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex (a.k.a. organophilic clay)		
00071-43-2	Benzene	0.005	0.001
119345-04-9	Benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts		
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide		
07440-41-7	Beryllium	0.004	0.004
	Bicarbonates (mg/L)		
00117-81-7	Bis(2-ethylhexyl)phthalate	0.005	0.005
10043-35-3	Boric acid		
07440-42-8	Boron		
24959-67-9	Bromide		
00075-27-4	Bromodichloromethane		
00075-25-2	Bromoform		
00074-83-9	Bromomethane	0.005	0.005
00071-36-3	Butan-1-ol	0.05	
68002-97-1	C10 - C16 Ethoxylated alcohol	0.05	
68131-39-5	C12-15 Alcohol, ethoxylated	0.05	
68439-51-0	C12-C14 Ethoxylated alcohols	0.05	
07440-43-9	Cadmium	0.005	0.005
07440-70-2	Calcium		
10043-52-4	Calcium chloride		
00124-38-9	Carbon dioxide		

TABLE 4.1
Substances Found in Frac Fluid or Flowback Water

CAS Number	Substance	NYSDOH MCL (mg/L)	NYSDEC Part 703 Health (Water Source) Standard (mg/L)
68130-15-4	Carboxymethylhydroxypropyl guar		
9004-34-6	Cellulose		
	Chloride	250	250
10049-04-4	Chlorine dioxide		
00124-48-1	Chlorodibromomethane		
00074-87-3	Chloromethane	0.005	
007440-47-3	Chromium	0.1	0.05
18540-29-9	Chromium (hexavalent)		0.05
16065-83-1	Chromium (trivalent)		
00077-92-9	Citric acid		
94266-47-4	Citrus terpenes		
07440-48-4	Cobalt		
68155-09-9	Cocamidopropylamine oxide		
68424-94-2	Coco-betaine (Cocamidopropyl Betaine)		
07440-50-8	Copper	1.3	0.2
07758-98-7	Copper (II) sulfate		
31726-34-8	Crissanol A-55		
14808-60-7	Crystalline silica (Quartz)		
7447-39-4	Cupric chloride dihydrate		
00057-12-5	Cyanide	0.2	0.2
1120-24-7	Decyldimethyl amine		
2605-79-0	Decyl-dimethyl amine oxide		
07727-54-0	Diammonium peroxidisulphate (ammonium persulfate)		
03252-43-5	Dibromoacetonitrile	0.05	
111-46-6	Diethylene glycol		
22042-96-2	Diethylenetriamine penta (methylenephonic acid) sodium salt		
28757-00-8	Diisopropyl naphthalenesulfonic acid		
07395-69-8	Dimethyladiallylammonium, chloride		
68607-28-3	Dimethylcocoamine, bis(chloroethyl) ether, diquaternary ammonium salt		
07398-69-8	Dimethyldiallylammonium chloride		
25265-71-8	Dipropylene glycol		
139-33-3	Disodium ethylene diamine tetra acetate		
5989-27-5	D-limonene		
123-01-3	Dodecylbenzene		
27176-87-0	Dodecylbenzene sulfonic acid		
42504-46-1	Dodecylbenzenesulfonate isopropanolamine		
50-70-4	D-Sorbitol		
37288-54-3	Endo-1,4-beta-mannanase (a.k.a. Hemicellulase)		
149879-98-1	Erucic amidopropyl dimethyl Betaine		
89-65-6	Erythorbic acid, anhydrous		
54076-97-0	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer		
107-21-1	Ethane	0.05	
9002-93-1	Ethoxylated 4-tert-octylphenol		
66455-15-0	Ethoxylated Alcohols	0.05	
34398-01-1	Ethoxylated C11 alcohol	0.05	
61791-12-6	Ethoxylated castor oil	0.05	
68439-45-2	Ethoxylated hexanol		
09036-19-5	Ethoxylated octylphenol	0.05	
9005-67-8	Ethoxylated Sorbitan Monostearate		
9004-70-3	Ethoxylated sorbitan trioleate		
00064-17-5	Ethyl alcohol	0.05	

TABLE 4.1
Substances Found in Frac Fluid or Flowback Water

CAS Number	Substance	NYSDOH MCL (mg/L)	NYSDEC Part 703 Health (Water Source) Standard (mg/L)
00097-64-3	Ethyl Lactate		
00100-41-4	Ethylbenzene	0.005	
00107-21-1	Ethylene glycol	0.05	
5877-42-9	Ethyloctynol		
78330-21-9	Ethyloxylated branched C11-C14, C13-rich Alcohols		
68526-86-3	Exxal 13		
61791-29-5	Fatty acid, coco, ethoxylated		
61791-08-0	Fatty acid, coco, reaction product with ethanolamine, ethoxylated		
68188-40-9	Fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea		
9043-30-5	Fatty alcohol polyglycol ether surfactant		
7705-08-0	Ferric chloride		
16984-48-8	Fluoride	2.2	1.5
00050-00-0	Formaldehyde		
00075-12-7	Formamide		
29316-47-0	Formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane		
153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide (Com. Name: C-5476)		
64-18-6	Formic acid		
110-17-8	Fumaric acid		
65997-17-3	Glassy calcium magnesium phosphate		
00111-30-8	Glutaraldehyde	0.05	
56-81-5	Glycerol (glycerine)		
	GLYCOLS, TOTAL		
09000-30-0	Guar gum		
09000-30-01	Guar gum (GW-3)		
64742-94-5	Heavy aromatic petroleum naptha		
09025-56-3	Hemicellulase		
09012-54-8	Hemicellulase enzyme		
07647-01-0	Hydrochloric acid		
7722-84-1	Hydrogen peroxide		
00079-14-1	Hydroxyacetic acid		
35249-89-9	Hydroxyacetic acid ammonium salt		
9004-62-0	Hydroxyethyl cellulose		
5470-11-1	Hydroxylamine hydrochloride		
39421-75-5	Hydroxypropyl guar		
07439-89-6	Iron	0.3	0.3
6381-77-7	Isoascorbic acid, sodium (a.k.a. sodium erythorbate)		
35674-56-7	Isomeric aromatic ammonium salt		
64742-88-7	Isoparaffinic petroleum hydrocarbons, synthetic (medium aliphatic solvent naphtha)		
00064-63-0	Isopropanol	0.05	
00067-63-0	Isopropanol (a.k.a. 2-Propanol; Propan-2-ol; Isopropyl Alcohol)	0.05	
08008-20-6	Kerosene		
64742-81-0	Kerosine (petroleum), hydrosulfurized		
63-42-3	Lactose		
07439-92-1	Lead	0.015	0.05
1120-21-4	Light paraffin oil		
07439-93-2	Lithium		
07439-95-4	Magnesium		35
14807-96-6	Magnesium Silicate Hydrate (Talc)		
07439-96-5	Manganese	0.3	0.3

TABLE 4.1
Substances Found in Frac Fluid or Flowback Water

CAS Number	Substance	NYSDOH MCL (mg/L)	NYSDEC Part 703 Health (Water Source) Standard (mg/L)
07439-95-4	Magnesium		35
14807-96-6	Magnesium silicate hydrate (Talc)		
07439-96-5	Manganese	0.3	0.3
07439-97-6	Mercury	0.002	0.0007
1184-78-7	Methanamine, N,N-dimethyl-, N-oxide		
67-56-1	Methanol	0.05	
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched		
08052-41-3	Mineral spirits (a.k.a. Stoddard Solvent)		
07439-98-7	Molybdenum		
00141-43-5	Monoethanolamine		
44992-01-0	N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride		
64742-48-9	Naphtha (petroleum), hydrotreated heavy		
91-20-3	Naphthalene		
38640-62-9	Naphthalene bis(1-methylethyl)		
93-18-5	Naphthalene, 2-ethoxy-		
68909-18-2	N-benzyl-alkyl-pyridinium chloride		
68139-30-0	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine		
07440-02-0	Nickel		0.1
	Nitrobenzene-d5		
	*Nitrogen, Total as N	10	10
7727-37-9	Nitrogen, liquid form		
09016-45-9	Nonylphenol ethoxylate	0.05	
26027-38-3	Nonylphenol ethoxylate		
127087-87-0	Nonylphenol ethoxylated (a.k.a. Oxylalkylated Phenol)	0.05	
68412-54-4	Nonylphenol polyethoxylate	0.05	
	Oil and grease		
	o-Terphenyl		
09003-11-6	Oxirane, methyl-, polymer with oxirane (a.k.a. Polyether Polyol DB 2061)		
51838-31-4	Oxiranemthanaminium, N,N,N-trimethyl-,chloride, homopolymer (aka Polyepichlorohydrin, trimethylamine quaternized)		
64742-65-0	Petroleum base oil		
64741-68-0	Petroleum naphtha		
	Phenol-d5		
	Phenols		
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis (methylene)]]tetrakis-, ammonium salt		
57723-14-0	Phosphorus (as P)		
8000-41-7	Pine oil		
60828-78-6	Poly(oxy-1,2-ethanediyl), a-[3,5-dimethyl-1-(2-methylpropyl)hexyl]-w-hydroxy-	0.05	
25322-68-3	Poly(oxy-1,2-ethanediyl), a-hydro-w-hydroxy- (a.k.a. Polyethylene Glycol)		
24938-91-8	Poly(oxy-1,2-ethanediyl), α-tridecyl-ω-hydroxy-		
56449-46-8	Polyethlene glycol oleate ester		
09005-65-6	Polyoxyethylene sorbitan monooleate	0.05	
61791-26-2	Polyoxylated fatty amine salt		
07440-09-7	Potassium		
00127-08-2	Potassium acetate		

TABLE 4.1
Substances Found in Frac Fluid or Flowback Water

CAS Number	Substance	NYSDOH MCL (mg/L)	NYSDEC Part 703 Health (Water Source) Standard (mg/L)
20786-60-1	Potassium borate		
584-08-7	Potassium carbonate		
7447-40-7	Potassium chloride		
590-29-4	Potassium formate		
1310-58-3	Potassium hydroxide		
13709-94-9	Potassium metaborate		
24634-61-5	Potassium sorbate		
112926-00-8	Precipitated silica (a.k.a silica gel)		
00107-19-7	Propargyl alcohol (a.k.a. Prop-2-yn-1-ol, 2-Propyn-1-ol)	0.05	
00057-55-6	Propylene glycol (a.k.a. Propane-1,2-diol)	1	
107-98-2	Propylene glycol monomethyl ether		
68953-58-2	Quaternary ammonium compounds bis[Hydrogenated Tallow Alkyl] dimethyl salts with bentonite		
62763-89-7	Quinoline,2-methyl-, hydrochloride		
15619-48-4	Quinolinium, 1-(phenylmethl),chloride		
68527-49-1	Reaction product of acetophenone, formaldehyde, thiourea and oleic acid in dimethyl formamide		
P-89-667	Salt of amine-carbonyl condensate		
07782-49-2	Selenium	0.05	0.01
7631-86-9	Silica, amorphous - fumed		
07440-22-4	Silver	0.1	0.05
07440-23-5	Sodium		20
5324-84-5	Sodium 1-octanesulfonate		
127-09-3	Sodium acetate		
95371-16-7	Sodium alpha-olefin sulfonate		
532-32-1	Sodium benzoate		
144-55-8	Sodium bicarbonate		
7631-90-5	Sodium bisulfate		
07647-15-6	Sodium bromide		
3926-62-3	Sodium chloracetate		
07647-14-5	Sodium chloride		
7758-19-2	Sodium chlorite		
68-04-2	Sodium citrate		
497-19-8	Sodium crbonate		
2836-32-0	Sodium glycolate		
1310-73-2	Sodium hydroxide		
7681-52-9	Sodium hypochlorite		
7775-19-01	Sodium metaborate.8H20		
10486-00-7	Sodium perborate tetrahydrate		
10486-00-7	Sodium perborate tetrahydrate		
7775-27-1	Sodium persulfate		
9003-04-7	Sodium polyacrylate		
7757-82-6	Sodium sulfate		
01303-96-4	Sodium tetraborate decahydrate		
7772-98-7	Sodium thousulfate		

TABLE 4.1
Substances Found in Frac Fluid or Flowback Water

CAS Number	Substance	NYSDOH MCL (mg/L)	NYSDEC Part 703 Health (Water Source) Standard (mg/L)
01338-43-8	Sorbitan monooleate	0.05	
07440-24-6	Strontium		
57-50-1	Sucrose		
5329-14-6	Sulfamic acid		
14808-79-8	Sulfate (as SO4)	250	250
	Sulfide (as S)		
14265-45-3	Sulfite (as SO3)		
68439-57-6	Sulfonates, alkyl (C14-16) olefin, sodium salt		
68155-20-4	Tall oil fatty acid diethanolamine		
61790-12-3	Tall oil fatty acids		
8052-48-0	Tallow fatty acids sodium salt		
68647-72-3	Terpene and terpenoids		
68956-56-9	Terpene hydrocarbon byproducts		
00127-18-4	Tetrachloroethene	0.005	0.005
00533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)	0.05	
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate (THPS)	0.05	
00075-57-0	Tetramethyl ammonium chloride		
00064-02-8	Tetrasodium ethylenediaminetetraacetate		
07440-28-0	Thallium	0.002	
00068-11-1	Thioglycolic acid		
62-56-6	Thiourea		
07440-32-6	Titanium		
00108-88-3	Toluene	0.005	0.005
	Total Organic Carbon		
	Total Suspended Solids		
	TPH (Gasoline Range)		
81741-28-8	Tributyl tetradecyl phosphonium chloride		
68299-02-5	Triethanolamine hydroxyacetate		
112-27-6	Triethylene glycol		
52624-57-4	Trimethylolpropane, ethoxylated, propoxylated		
150-38-9	Trisodium ethylenediaminetetraacetate		
5064-31-3	Trisodium nitrilotriacetate		
7601-54-9	Trisodium ortho phosphate		
00057-13-6	Urea		
07440-62-2	Vanadium		
25038-72-6	Vinylidene chloride/Methylacrylate copolymer		
07732-18-5	Water		
62649-23-4	Water soluble polymer		
01330-20-7	Xylene	0.005	0.005
07440-66-6	Zinc	5	
7440-67-7	Zirconium		

Radiological Parameters not included in table

TABLE 4.2
Frac Fluid Constituents with MCLs or Standards

Constituent	CAS Number	NYSDOH Part 5 MCL (mg/L)	NYSDEC Part 703 Health (Water Source) Standard (mg/L)
1,2,4 trimethylbenzene	95-63-6	0.005	0.005
2,2 Dibromo-3-nitrilopropionamide	10222-01-2	0.05	
2,2-Dibromomalonamide	73003-80-2	0.05	
2-Butoxy ethanol (ethylene glycol monobutyl ether)	111-76-2	0.05	
2-Dibromo-3-nitriloprionamide (a.k.a 2-Monobromo-3-nitrilopropionamide)	1113-55-9	0.05	
2-Ethyl hexanol	104-767-7	0.05	
3-Methyl-1-butyn-3-ol	115-19-5	0.05	
Acrylamide	79-06-1	0.005	0.005
Alcohols C9-11, ethoxylated (a.k.a. Ethoxylated Alcohol)	68439-46-3	0.05	
Alcohols C10-12, ethoxylated	67254-71-1	0.05	
Alcohols, C12-14-secondary, ethoxylated	84133-50-6	0.05	
Alcohols, C12-C16, ethoxylated (a.k.a. Ethoxylated alcohol)	68551-12-2	0.05	
Alcohols C14-15, ethoxylated	68951-67-7	0.05	
Aqueous ammonia	7664-41-7		0.0007 - 0.370
Benzene	71-43-2	0.005	0.001
Butan-1-ol (butanol; 1-butanol)	71-36-3	0.05	
C10 - C16 Ethoxylated alcohol	68002-97-1	0.05	
C12-15 Alcohol, ethoxylated	68131-39-5	0.05	
C12-C14 Ethoxylated alcohols	68439-51-0	0.05	
Dibromoacetonitrile	3252-43-5	0.05	
Ethane	107-21-1	0.05	
Ethoxylated alcohols	66455-15-0	0.05	
Ethoxylated C11 alcohol	34398-01-1	0.05	
Ethoxylated castor oil	61791-12-6	0.05	
Ethoxylated octylphenol	9036-19-5	0.05	
Ethyl alcohol	64-17-5	0.05	
Ethylbenzene	100-41-4	0.005	0.005
Ethylene glycol	107-21-1	0.05	
Formaldehyde (impurity)	50-00-0		0.008
Glutaraldehyde	111-30-8	0.05	
Isopropanol (a.k.a. 2-Propanol; Propan-2-ol; Isopropyl Alcohol)	67-63-0 or 64-63-0	0.05	
Methanol	67-56-1	0.05	
Nonylphenol ethoxylate	9016-45-9	0.05	
Nonylphenol ethoxylated (a.k.a. Oxylalkylated Phenol)	127087-87-0	0.05	
Nonylphenol polyethoxylate	68412-54-4	0.05	
Poly(oxy-1,2-ethanediyl), a-[3,5-dimethyl-1-(2-methylpropyl)hexyl]-w-hydroxy-	60828-78-6	0.05	
Polyoxyethylene sorbitan monooleate	9005-65-6	0.05	
Propargyl alcohol (a.k.a. Prop-2-yn-1-ol)	107-19-1	0.05	
Propylene glycol (a.k.a. Propane-1,2-diol)	57-55-6	1	
Sorbitan monooleate	1338-43-8	0.05	
Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)	5333-74-4	0.05	
Tetrakis(hydroxymethyl)phosphonium sulfate (THPS)	55566-30-8	0.05	
Toluene	108-88-3	0.005	0.005
Triethylene glycol	112-27-6	0.05	
Xylene	1330-20-7	0.005	0.005

Note: Chemicals listed are based on vertical or horizontal frac jobs

TABLE 4.3
Theoretical Concentration of Frac Fluid Chemicals in WOH Reservoirs During Drought Conditions

Assumptions

- Total amount of chemical needed to complete the specificed # of wells is stored on site simultaneously
- Total volume of chemical is spilled directly into the reservoir system.
- Complete mixing of chemical within the reservoir system
- No soil adsorption, evaporation, or other attenuation processes occur
- All reservoir capacities are under severe drought conditions, 33% capacity each
- No spill detection, and no attempt made to mitigate or clean spill

Frac Fluid Mix 1 (includes a surfactant, a clay inhibitor, a friction reducer, and a biocide)

Frac Fluid Mix 1 Chemicals	NYSDOH Part 5 MCL (mg/L)	MCL Theoretically Exceeded in Reservoir During Drought Conditions? [1]																	
		Based on Total Weight of Chemicals Needed to Complete One Horizontal Well						Based on Total Weight of Chemicals Needed to Complete Two Horizontal Wells						Based on Total Weight of Chemicals Needed to Complete Eight Horizontal Wells					
		S [2]	N	R	C	A	P	S	N	R	C	A	P	S	N	R	C	A	P
2,2,-Dibromo-3-Nitrilopropionamide	0.05	yes	yes	no	no	no	no	yes	yes	yes	yes	no	no	yes	yes	yes	yes	yes	yes
Alcohols C9-11, ethoxylated	0.05	no	no	no	no	no	no	no	no	no	no	no	no	yes	yes	yes	no	no	no
Ethoxylated C11 Alcohol	0.05	no	no	no	no	no	no	yes	no	no	no	no	no	yes	yes	yes	no	no	no
Methanol	0.05	yes	no	no	no	no	no	yes	yes	yes	no	no	no	yes	yes	yes	yes	yes	yes
Ethylene Glycol	0.05	yes	no	no	no	no	no	yes	yes	no	no	no	no	yes	yes	yes	yes	yes	yes

Frac Mix 2 (includes a friction reducer, a biocide, and a surfactant)

Frac Fluid Mix 2 Chemicals	NYSDOH Part 5 MCL (mg/L)	MCL Theoretically Exceeded in Reservoir During Drought Conditions? [1]																	
		Based on Total Weight of Chemicals Needed to Complete One Horizontal Well						Based on Total Weight of Chemicals Needed to Complete Two Horizontal Wells						Based on Total Weight of Chemicals Needed to Complete Eight Horizontal Wells					
		S	N	R	C	A	P	S	N	R	C	A	P	S	N	R	C	A	P
2,2,-Dibromo-3-Nitrilopropionamide	0.05	no	no	no	no	no	no	yes	no	no	no	no	no	yes	yes	yes	no	no	no
C12-15 Alcohol, Ethoxylated	0.05	yes	no	no	no	no	no	yes	yes	no	no	no	no	yes	yes	yes	yes	yes	yes
Ethoxylated Castor Oil	0.05	no	no	no	no	no	no	yes	no	no	no	no	no	yes	yes	yes	no	no	no
Isopropanol (Isopropyl Alcohol)	0.05	no	no	no	no	no	no	yes	no	no	no	no	no	yes	yes	yes	no	no	no
Propylene Glycol	1	no	no	no	no	no	no	no	no	no	no	no	no	no	no	no	no	no	no

Notes:

1) Evaluation performed for frac mix chemicals which have NYSDOH (or NYSDEC) standards
2) S = Schoharie Reservoir, N = Neversink Reservoir, R = Rondout Reservoir, C = Cannonsville Reservoir, A = Ashokan Reservoir, P = Pepacton Reservoir

TABLE 4.4
New York City Reservoir Capacities

New York City West-Of-Hudson Reservoir Capacities

	Full Volume		Severe Drought Volume (1/3 capacity)	
Reservoir	**Gallons**	**Liters**	**Gallons**	**Liters**
Cannonsville	95,700,000,000	362,262,780,000	31,900,000,000	120,754,260,000
Pepacton	140,200,000,000	530,713,080,000	46,733,333,333	176,904,360,000
Neversink	34,900,000,000	132,110,460,000	11,633,333,333	44,036,820,000
Rondout	49,600,000,000	187,755,840,000	16,533,333,333	62,585,280,000
Ashokan	122,900,000,000	465,225,660,000	40,966,666,667	155,075,220,000
Schoharie	17,600,000,000	66,623,040,000	5,866,666,667	22,207,680,000
Total	460,900,000,000	1,744,690,860,000	153,633,333,333	581,563,620,000

Selected New York City East-Of-Hudson Reservoir Capacities

	Full Volume		Severe Drought Volume (1/3 capacity)	
Reservoir	**Gallons**	**Liters**	**Gallons**	**Liters**
West Branch	8,000,000,000	30,283,200,000	2,666,666,667	10,094,400,000
Kensico	30,600,000,000	115,833,240,000	10,200,000,000	38,611,080,000
Total	38,600,000,000	146,116,440,000	166,500,000,000	48,705,480,000

Source for Reservoir Volumes at Full Capacity: NYCDEP

TABLE 4.5
Theoretical Concentration of Frac Fluid Chemicals at EOH Outlets and NYC Intakes During Drought Conditions

Assumptions

- Total amount of chemical needed to complete the specificed # of wells is stored on site simultaneously
- Total volume of chemical is spilled directly into the reservoir system.
- Complete mixing of chemical within the reservoir system
- No soil adsorption, evaporation, or other attenuation processes occur
- All reservoir capacities are under severe drought conditions, 33% capacity each
- No spill detection, and no attempt made to mitigate or clean spill

Frac Fluid Mix 1 (includes a surfactant, a clay inhibitor, a friction reducer, and a biocide)

Frac Fluid Mix 1 Chemicals	NYSDOH Part 5 MCL (mg/L)	MCL Theoretically Exceeded in During Drought Conditions? [1]								
		Based on Total Weight of Chemicals Needed to Complete One Horizontal Well			Based on Total Weight of Chemicals Needed to Complete Two Horizontal Wells			Based on Total Weight of Chemicals Needed to Complete Eight Horizontal Wells		
		Kensico	West Branch	Hillview	Kensico	West Branch	Hillview	Kensico	West Branch	Hillview
2,2,-Dibromo-3-Nitrilopropionamide	0.05	no	no	no	no	no	no	yes	yes	no
Alcohols C9-11, ethoxylated	0.05	no	no	no	no	no	no	no	no	no
Ethoxylated C11 Alcohol	0.05	no	no	no	no	no	no	no	no	no
Methanol	0.05	no	no	no	no	no	no	yes	no	no
Ethylene Glycol	0.05	no	no	no	no	no	no	yes	no	no

Frac Mix 2 (includes a friction reducer, a biocide, and a surfactant)

Frac Fluid Mix 2 Chemicals	NYSDOH Part 5 MCL (mg/L)	MCL Theoretically Exceeded in During Drought Conditions?								
		Based on Total Weight of Chemicals Needed to Complete One Horizontal Well			Based on Total Weight of Chemicals Needed to Complete Two Horizontal Wells			Based on Total Weight of Chemicals Needed to Complete Eight Horizontal Wells		
		Kensico	West Branch	Hillview	Kensico	West Branch	Hillview	Kensico	West Branch	Hillview
2,2,-Dibromo-3-Nitrilopropionamide	0.05	no	no	no	no	no	no	no	no	no
C12-15 Alcohol, Ethoxylated	0.05	no	no	no	no	no	no	yes	no	no
Ethoxylated Castor Oil	0.05	no	no	no	no	no	no	no	no	no
Isopropanol (Isopropyl Alcohol)	0.05	no	no	no	no	no	no	no	no	no
Propylene Glycol	1	no	no	no	no	no	no	no	no	no

Notes:

1) Evaluation performed for frac mix chemicals which have NYSDOH (or NYSDEC) standards

TABLE 4.6
Theoretical Flowback Water Chemical Constituents in Two 20,000-gallon Frac Tanks

CAS No.	Parameter	NYSDOH MCL (mg/L)	NYSDEC Part 703 Health Water Source Standard (mg/L)	Max from Flowback data provided by NYSDEC (mg/L)	Amount of Chemical in Two 20,000-gallon frac tanks full of flowback water	
					pounds	kg
07664-41-7	Ammonia/ammonium		2	382	127.25	57.84
07440-36-0	Antimony	0.006	0.003	0.26	0.087	0.039
07440-38-2	Arsenic	0.01	0.05	0.123	0.041	0.019
07440-39-3	Barium	2	1	19,200	6,395.81	2907.19
00071-43-2	Benzene	0.005	0.001	1.95	0.650	0.30
07440-41-7	Beryllium	0.004		422	140.57	63.90
00117-81-7	Bis(2-ethylhexyl)phthalate	0.005	0.005	0.0215	0.0072	0.003
07440-42-8	Boron		1	26.8	8.93	4.06
00074-83-9	Bromomethane	0.005	0.005	0.002	0.00067	0.0003
07440-43-9	Cadmium	0.005	0.005	1.2	0.40	0.18
	Chloride	250	250	188,000	62,625.66	28466.21
00074-87-3	Chloromethane	0.005		0.0156	0.005	0.002
07440-47-3	Chromium	0.1	0.05	760	253.17	115.08
18540-29-9	Chromium (hexavalent)		0.05	9.22	3.07	1.40
07440-50-8	Copper	1.3	0.2	0.157	0.052	0.024
00057-12-5	Cyanide	0.2	0.2	0.019	0.006329	0.0029
00100-41-4	Ethylbenzene	0.005	0.005	0.164	0.055	0.025
16984-48-8	Fluoride	2.2	1.5	780	259.83	118.10
07439-89-6	Iron	0.3	0.3	810	269.82	122.65
07439-92-1	Lead	0.015	0.05	27.4	9.13	4.15
07439-95-4	Magnesium		35	8,208	2,734.21	1242.82
07439-96-5	Manganese	0.3	0.3	97.6	32.51	14.78
07439-97-6	Mercury	0.002	0.0007	0.59	0.20	0.09
07440-02-0	Nickel		0.1	0.137	0.046	0.021
	*Nitrogen, Total as N	10	10	13.4	4.46	2.03
07782-49-2	Selenium	0.05	0.01	1.06	0.353	0.161
07440-22-4	Silver	0.1	0.05	6.3	2.10	0.95
07440-23-5	Sodium		20	96,700	32,212.24	14641.93
14808-79-8	Sulfate (as SO4)	250	250	1,270	423.06	192.30
00127-18-4	Tetrachloroethene	0.005	0.005	0.005	0.0017	0.001
07440-28-0	Thallium	0.002		0.26	0.09	0.04
00108-88-3	Toluene	0.005	0.005	3.19	1.063	0.483
01330-20-7	Xylenes, Total	0.005	0.005	2.67	0.889	0.404
07440-66-6	Zinc	5		8,570	2,854.8	1297.64

Parameters listed have NYSDOH, or NYSDEC standards.
Radiological Parameters not included in table
*Nitrogen, Total

TABLE 4.7
Theoretical Concentration of Flowback Constituents in WOH Reservoirs

ASSUMPTIONS

Two 20,000-gal frac tanks (or 40,000 gal from lagoon) empty completely and directly into the reservoir system
Complete mixing of chemical within the reservoir system
No evaporation
No adsorption by soil
No attempt made to mitigate or clean spill

Compound in Flowback Water (mg/L)	Total Weight of Contaminant in Solution in Two 20,000-gallon Frac Tanks (kg) [from Table 4.6]	MCL Theoretically Exceeded in Reservoir under Drought Conditions if 40,000 gal of Flowback Water Spilled into Reservoir from Frac Tanks, or from Lagoons						Threshold	
		Cannonsville	Pepacton	Neversink	Rondout	Ashokan	Schoharie	NYSDOH Part 5 MCL (mg/L)	NYSDEC Part 703 Health (Water Source) Standard (mg/L)
Ammonia/ammonium	57.84	no	no	no	no	no	no		2
Antimony	0.039	no	no	no	no	no	no	0.006	0.003
Arsenic	0.019	no	no	no	no	no	no	0.01	0.05
Barium	2,907.19	no	no	no	no	no	no	2	1
Benzene	0.3	no	no	no	no	no	no	0.005	0.001
Beryllium	63.90	no	no	no	no	no	no	0.004	
Bis(2-ethylhexyl)phthalate	0.003	no	no	no	no	no	no	0.005	0.005
Boron	4.06	no	no	no	no	no	no		1
Bromomethane	0.0003	no	no	no	no	no	no	0.005	0.005
Cadmium	0.180	no	no	no	no	no	no	0.005	0.005
Chloride	28,466.21	no	no	no	no	no	no	250	250
Chloromethane	0.002	no	no	no	no	no	no	0.005	
Chromium	115.08	no	no	no	no	no	no	0.1	0.05
Chromium (hexavalent)	1.40	no	no	no	no	no	no		0.05
Copper	0.024	no	no	no	no	no	no	1.3	0.2
Cyanide	0.0029	no	no	no	no	no	no	0.2	0.2
Ethylbenzene	0.025	no	no	no	no	no	no	0.005	0.005
Fluoride	118.10	no	no	no	no	no	no	2.2	1.5
Iron	122.65	no	no	no	no	no	no	0.3	0.3
Lead	4.15	no	no	no	no	no	no	0.015	0.05
Magnesium	1,242.82	no	no	no	no	no	no		35
Manganese	14.78	no	no	no	no	no	no	0.3	0.3
Mercury	0.09	no	no	no	no	no	no	0.002	0.0007
Nickel	0.021	no	no	no	no	no	no		0.1
Nitrogen, Total as N	2.03	no	no	no	no	no	no	10	10
Selenium	0.161	no	no	no	no	no	no	0.05	0.01
Silver	0.95	no	no	no	no	no	no	0.1	0.05
Sodium	14,641.93	no	no	no	no	no	no		20
Sulfate (as SO4)	192.30	no	no	no	no	no	no	250	250
Tetrachloroethene	0.001	no	no	no	no	no	no	0.005	0.005
Thallium	0.04	no	no	no	no	no	no	0.002	
Toluene	0.483	no	no	no	no	no	no	0.005	0.005
Xylenes, Total	0.404	no	no	no	no	no	no	0.005	0.005
Zinc	1,297.64	no	no	no	no	no	no	5	

Table 7.1
Modified Mercalli Intensity Scale

Modified Mercalli Intensity	Description	Effects	Typical Maximum Moment Magnitude
I	Instrumental	Not felt except by a very few under especially favorable conditions.	1.0 to 3.0
II	Feeble	Felt only by a few persons at rest, especially on upper floors of buildings.	3.0 to 3.9
III	Slight	Felt quite noticeably by persons indoors, especially on upper floors of buildings. Many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibrations similar to the passing of a truck. Duration estimated.	
IV	Moderate	Felt indoors by many, outdoors by few during the day. At night, some awakened. Dishes, windows, doors disturbed; walls make cracking sound. Sensation like heavy truck striking building. Standing motor cars rocked noticeably.	4.0 to 4.9
V	Rather Strong	Felt by nearly everyone; many awakened. Some dishes, windows broken. Unstable objects overturned. Pendulum clocks may stop.	
VI	Strong	Felt by all, many frightened. Some heavy furniture moved; a few instances of fallen plaster. Damage slight.	5.0 to 5.9
VII	Very Strong	Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable damage in poorly built or badly designed structures; some chimneys broken.	
VIII	Destructive	Damage slight in specially designed structures; considerable damage in ordinary substantial buildings with partial collapse. Damage great in poorly built structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned.	6.0 to 6.9
IX	Ruinous	Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb. Damage great in substantial buildings, with partial collapse. Buildings shifted off foundations.	
X	Disastrous	Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations. Rails bent.	7.0 and higher
XI	Very Disastrous	Few, if any (masonry) structures remain standing. Bridges destroyed. Rails bent greatly.	
XII	Catastrophic	Damage total. Lines of sight and level are distorted. Objects thrown into the air.	

The above table compares the Modified Mercalli intensity scale and moment magnitude scales that typically observed near the epicenter of a seismic event.

Source: USGS Earthquake Hazard Program (http://earthquake.usgs.gov/learning/topics/mag_vs_int.php)

Table 7.2
Summary of Seismic Events in New York State
December 1970 through July 2009

County	Magnitude					Total
	< 2.0	2.0 to 2.9	3.0 to 3.9	4.0 to 4.9	5.0 to 5.3	
Counties Overlying Utica and Marcellus Shales						
Albany	27	20	3	0	0	50
Allegany	0	0	0	0	0	0
Broome	0	0	0	0	0	0
Cattaraugus	0	0	0	0	0	0
Cayuga	0	0	0	0	0	0
Chautauqua	0	0	0	0	0	0
Chemung	0	0	0	0	0	0
Chenango	0	0	0	0	0	0
Cortland	0	0	0	0	0	0
Delaware	1	2	0	0	0	3
Erie	7	5	0	0	0	12
Genesee	3	5	0	0	0	8
Greene	2	1	0	0	0	3
Livingston	1	5	1	0	0	7
Madison	0	0	0	0	0	0
Montgomery	1	2	0	0	0	3
Niagara	7	3	0	0	0	10
Onondaga	0	0	0	0	0	0
Ontario	1	1	0	0	0	2
Otsego	0	0	0	0	0	0
Schoharie	2	4	0	1	0	7
Schuyler	0	0	0	0	0	0
Seneca	0	0	0	0	0	0
Steuben	2	0	1	0	0	3
Sullivan	0	0	0	0	0	0
Tioga	0	0	0	0	0	0
Tompkins	0	0	0	0	0	0
Wyoming	8	5	0	0	0	13
Yates	1	0	0	0	0	1
Subtotal	*63*	*53*	*5*	*1*	*0*	*122*
Counties Overlying Utica Shale						
Fulton	1	2	1	0	0	4
Herkimer	4	3	0	0	0	7
Jefferson	5	3	0	0	0	8
Lewis	3	0	2	0	0	5
Monroe	1	0	0	0	0	1
Oneida	3	4	0	0	0	7
Orange	14	5	0	0	0	19
Orleans	0	0	0	0	0	0
Oswego	2	0	0	0	0	2
Saratoga	1	2	0	0	0	3
Schenectady	1	1	0	0	0	2
Wayne	0	0	0	0	0	0
Subtotal	*35*	*20*	*3*	*0*	*0*	*58*

Table 7.2
Summary of Seismic Events in New York State
December 1970 through July 2009

County	Magnitude					Total
	< 2.0	2.0 to 2.9	3.0 to 3.9	4.0 to 4.9	5.0 to 5.3	
Counties Not Overlying Utica or Marcellus Shales						
Bronx	0	0	0	0	0	0
Clinton	60	30	5	0	1	96
Columbia	0	0	0	0	0	0
Dutchess	6	4	2	0	0	12
Essex	88	64	4	1	1	158
Franklin	40	19	3	0	0	62
Hamilton	53	10	0	0	0	63
Kings	0	0	0	0	0	0
Nassau	1	0	0	0	0	1
New York	3	2	0	0	0	5
Putnam	4	2	0	0	0	6
Queens	0	0	0	0	0	0
Rensselaer	1	0	0	0	0	1
Richmond	0	0	0	0	0	0
Rockland	15	3	0	0	0	18
St. Lawrence	84	29	0	0	0	113
Suffolk	0	0	0	0	0	0
Ulster	3	0	0	0	0	3
Warren	11	5	1	0	0	17
Washington	1	3	0	0	0	4
Westchester	61	11	1	1	0	74
Subtotal	*431*	*182*	*16*	*2*	*2*	*633*
New York State Total	***529***	***255***	***24***	***3***	***2***	***813***

Notes:
- Seismic events recorded December 13, 1970 through July 28, 2009.
- Lamont-Doherty Cooperative Seismographic Network, 2009