Gas Shale Rush:  
A Guide To The Legal Issues

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*S Cornell Law School Water Law Clinic students, assisting the Upper Susquehanna Coalition (USC), a group of soil and water conservation district managers in southern New York and Pennsylvania, in educating its members on the current and future laws that govern Marcellus Shale gas drilling. This draft guidance document is intended for public officials and technical providers and will continue to be shaped as the DEC develops its Marcellus Shale regulatory scheme.

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# Table of Contents

Acknowledgements *(To be drafted)*
Executive Summary *(To be drafted)*
List of Figures
List of Tables

Overview .......................................................................................................................... 4
  Marcellus Shale ........................................................................................................... 4
  Objectives and Goals ................................................................................................. 4

Water Quantity, Quality and Sediment: Regulatory Concerns ..................................... 5
  Introduction .................................................................................................................. 5
    Regulatory Scheme .................................................................................................... 5
    Overview: Gas Permitting and Drilling ..................................................................... 6
  Water Quantity ............................................................................................................. 8
    Recommendations ..................................................................................................... 10
  Water Quality ............................................................................................................. 10
    Recommendations ..................................................................................................... 18
  Sediment and Erosion ................................................................................................. 19
    Recommendations ..................................................................................................... 22

State Environmental Quality Review Act (SEQR) ....................................................... 23
  Background .................................................................................................................. 23
  Process and Factors .................................................................................................... 23
  The Generic Environmental Impact Statement (GEIS) ............................................... 24
  State Environmental Quality Review Act (SEQR) ....................................................... 25
    Recommendations ..................................................................................................... 29

Pipelines ...................................................................................................................... 30
  Background .................................................................................................................. 30
  Types of Pipelines ....................................................................................................... 30
    Ground Coverage, Location and Spacing ................................................................ 31
    Pollutants and Stormwater Discharges ................................................................... 32
    Safety and Maintenance .......................................................................................... 33
    Technical DPS Regulatory Questions ..................................................................... 34
  Public Participation for Siting and Construction ....................................................... 35

Appendices:
  A: Gas Leases ............................................................................................................. 37
  B: Eminent Domain .................................................................................................... 49
  C: Conflict Resolution ............................................................................................... 51
  D: Potential Environmental & Community Impacts ................................................... 52
  E: Federal, State and Local Law .................................................................................. 63
    Accommodation Doctrine ......................................................................................... 65
    Well Spacing and siting ............................................................................................ 66
  F: Acronyms and Glossary ........................................................................................ 68
  G: Technical Resources ............................................................................................. 70
  H: References *(Not included)*

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Overview

Marcellus Shale

The Marcellus Shale is a black shale formation that extends deep underground from southern New York into Pennsylvania, Ohio and West Virginia. “Although the Marcellus Shale is exposed at the ground surface in some locations in the northern Finger Lakes area, it is as deep as 7,000 feet or more below the ground surface along the Pennsylvania border in the Delaware River valley.” Gas drilling activity in the Marcellus Shale is expected to be concentrated in areas where the Shale is deeper than 2,000 feet.¹

The gas industry is interested in the Marcellus Shale because of the natural gas it contains and because recent developments in technology have made drilling for gas economically viable. “Geologists estimate that the entire Marcellus Shale formation contains between 168 trillion to 516 trillion cubic feet of natural gas throughout its entire extent.” Although this could suffice to meet US demand for up to 20 years, it is not currently known how much of the natural gas can feasibly be commercially recovered from the portion of the Marcellus in New York. The density and depth of the Shale previously made exploring and extracting gas an expensive proposition. However, recent enhancements to horizontal drilling and hydraulic fracturing technology have made exploring gas in the Shale a viable option. The gas industry’s interest has also increased due to “the proximity of high natural gas demand markets in New York, New Jersey and New England and the construction of the Millenium Pipeline through the Southern Tier.”²

Objectives and Goals

This guide deals with broad concerns regarding water quantity, water quality, sediment and erosion, and pipelines, as well as information about SEQR, New York State’s environmental quality review process. The guide has a particular focus on information that will be helpful to public officials and technical providers, including the Soil and Water Conservation District staff. A goal of this study is to promote prevention and mitigation of damage to soil and water systems wherever possible, by encouraging cooperation between the government, environmental professionals, and gas drilling companies for their mutual benefit. The gas resources lying in the Marcellus Shale represent a huge economic benefit to the Northeastern US. Their development and production provide a critical opportunity to balance and integrate our economic and environmental needs.

Water Quantity, Quality and Sediment: 
Regulatory Concerns

Introduction

The legal and regulatory scheme surrounding natural gas drilling in New York State is under transformation in an effort to address the unique concerns posed by widespread gas drilling proposed in the Marcellus Shale and other shale formations throughout the state. Gas production will primarily be accomplished through the use of the slick water hydro-fracturing drilling technique, also called “hydrofracking.” The hydraulic-fracturing process involves well siting, well drilling, well development and stimulation (“hydraulic-fracturing”), gas production, wastewater management, and well reclamation and closure. The potential environmental and water quality impacts vary depending on the stage of the process.

To address these concerns, New York State’s Department of Environmental Conservation (“DEC”) is currently reviewing a draft of the Supplemental Generic Environmental Impact Statement (SGEIS) regarding water quantity, water quality, and other environmental issues involved in the upcoming gas production that the DEC did not address in its original 1992 Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Program (1992 GEIS).

The DEC is currently reviewing written comments from the public for further development of the recently released draft of the SGEIS. The public comment process is a crucial opportunity for soil and water conservation professionals like Upper Susquehanna Coalition members to tell the government why the DEC should implement various regulatory positions to protect the health of New York State’s soil, water, landscape, and citizens.

Regulatory Scheme

Q1: What authority does the DEC have in relation to oil and gas in New York?
A1: The New York State legislature has instructed the DEC to develop oil, gas, and mineral resources in a manner that will prevent waste, insure the greatest economic recovery of oil and gas, and protect the correlative rights of all owners and all persons including the general public. 6 NYCRR 550.1. As a result, the DEC has issued rules that correspond with these responsibilities.

Q2: Which division within the DEC is responsible for regulating the oil and gas industry?
A2: The DEC’s Bureau of Mineral Resources is responsible for administering and enforcing the DEC’s rules relating to the exploration, drilling for, production, transportation, purchase, processing and storage of oil and gas in New York State. The Bureau of Mineral Resources is also responsible for preventing pollution from these oil and gas activities. 6 NYCRR 550.2.

Q3.5 What authority do local governments have to regulate hydraulic fracturing?
A3.5 ECL, Section 23-0303 states that state regulations “shall supersede all local laws and ordinances relating to the regulation of the oil, gas and solution mining industries; but shall not supersede local government jurisdiction over local roads or the rights of local governments under the real property tax
law.” The boundaries of this local jurisdiction have not been litigated in New York.

The SGEIS suggests a role for local governments regarding the following:

- Operators must obtain local floodplain permits. SGEIS 8.1.1.4.
- Operators are “strongly encouraged” to obtain road use agreements with local authorities. SGEIS 8.1.1.5.
- A permit applicant must “review” local planning documents. Even though the DEC’s final authority to issue well siting permits supersedes local governments. SGEIS 8.1.1.6.
- County Health Departments will bear the responsibility for initial response to most well water contamination complaints. The DEC will conduct a site specific review if active drilling is underway within a specified distance. SGEIS 8.1.1.7.

See SGEIS Table 8.1 for more detailed regulatory listings.

Q: Have courts ever found environmental review by a state agency preempted by federal law?
A: Yes. Federal law may preempt state law regarding regulation of pipeline construction and location. In one case, federal law preempted state regulation of natural gas pipeline construction project, and thus public utility did not improperly segment power purchase agreement requiring construction and operation of combustion turbine generator by failing to include construction of natural gas pipeline in its environmental review of project pursuant to State Environmental Quality Review Act (SEQRA), even though project and pipeline were part of integrated and cumulative development plan. McKinney’s ECL § 8–0101 et seq.; 6 NYCRR 617.2. East End Property Co. No. 1, LLC v. Kessel, 46 A.D.3d 817, 851 N.Y.S.2d 565 (2d Dep’t 2007), leave to appeal denied (N.Y. June 26, 2008).

In another case, Congress placed authority regarding the location of interstate pipelines-in the present case affecting citizens of four states in addition to New York-in the FERC, a federal body that can make choices in the interests of energy consumers nationally. Because FERC has authority to consider environmental issues, states may not engage in concurrent site-specific environmental review. National Fuel Gas Supply Corp. v. Public Service Com’n of State of N.Y., 109 P.U.R.4th 383, 894 F.2d 571, C.A.2 (N.Y.) 1990.

Hydraulic-fracturing is currently exempt from regulation under the CWA and the SDWA.

**Overview: Gas Permitting and Drilling Process**

Q: How long does the initial DEC permitting process take?
A: Each individual well is its own project and permitting time may vary. For an overview of the permitting process, see SGEIS 1.4.3.

Q: How long will drilling take?
A: Drilling usually takes four to eight weeks, varying with factors such as depth and time of year. Deep drilling may require up to two months. See DEP Report ES-3.

Q: What happens when drilling is complete?
A: Usually the land around the drilling site is reclaimed within 45 days. Vegetation will grow back with time.
Q: How much area does a well platform occupy?
A: Approximately two to five acres of land are cleared for a wellpad. NYSDEC spacing regulations require a 40 acre spacing unit for a single well and a 640 acre spacing unit for a multi-well site. The SGEIS strongly encourages multi-well sites.

Q: What should landowners expect in terms of equipment and disturbance during well drilling and hydraulic-fracturing?
A: During the well drilling phase of gas exploration, landowners should expect heavy equipment and the drilling rig to enter in and out of property during the drilling process. Gas companies will build access to accommodate this equipment and will clear trees and vegetation. Dust, noise, and exhaust fumes will occur during drilling. Wellhead assemblies, meters and tanks will remain on-site near the well location for the life of the well. Also, during the drilling phase, drilling fluid will be injected into the well.

During the hydraulic-fracturing phase, landowners can expect fracturing fluid to be injected into the wells. Landowners may expect the fracturing fluids to be stored at the wellhead and there may be potential for groundwater contamination.

Q: Who are the parties in gas interests, drilling, and production?
A: • Landmen
  • Exploration companies
  • Sub-contractors
  • Regulators
  • Landowners

Q: How are gas rights determined in New York?
A: Gas accumulates in underground rock formations known as reservoirs. These reservoirs vary in shape and size and do not follow the artificial property line boundaries on the surface of the land. Because of this, the New York State Department of Environmental Conversation (“DEC”) sets well “spacing units” which may consist of one or more properties. Land owners have rights in the gas underneath their property to the extent that this right has not been sold or otherwise given away. Owning the gas rights on property in a spacing unit entitles landowners to the opportunity to receive the benefits of drilling in that spacing unit. If landowners lease their land, their royalty payment under the lease is based on a given landowner’s share of the spacing unit. If a well operator does not own all of the gas rights in the spacing unit, the DEC must address this issue through the compulsory integration process. For more information, see Appendix A: Gas Leases.

Q: How are drilling violations remedied?
A: Article 23, Title 3 of the Environmental Conservation Law (“ECL”) authorizes the DEC to require that wells be drilled, constructed, operated and plugged, and the surrounding land reclaimed, to prevent or remedy “the escape of oil, gas, brine or water out of one stratum into another” and “the pollution of fresh water supplies by oil, gas, salt water or other contaminants.” The statute also gives the DEC authority to “order an immediate suspension of drilling or production operations whenever such operations are being carried on in violation [of the ECL].” ECL 23-0305(8)(d) and (g).

ECL Article 71, Title 13, grants the DEC broad authority to address violations of Article 23 or any regulation, order or permit condition. The statute allows the DEC to impose administrative sanctions, including civil penalties of up to $5,000 for a violation or offense and up to $1,000 for each day a
violation continues. The DEC Commissioner “has the power to direct the violator cease the violation and reclaim and repair the affected site.” ECL 71-1307(1).

Article 71 also gives the New York Attorney General authority to impose civil sanctions and criminal sanctions, with penalties or fines of up to $1,000 per day for continuing violations and up to one year imprisonment, or both. The DEC, acting through the Attorney General, may also seek court injunctions forbidding a violator from participating in violations or threatened violations of Article 23.

**Water Quantity**

**Q:** How much water will hydrofracking consume?  
**A:** Estimates on water consumption vary, with water measured in the millions of gallons; anywhere from 2.4 to 7.8 million gallons of water might be used for each fracking. SGEIS §5.7.  

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Once water is used in fracking, some water comes back up to the surface, and some water remains in the rock formations. The water that does not resurface is considered to be permanently removed from its watershed.

**Q:** Who regulates water withdrawals in New York State?  
**A:** The DEC regulates water withdrawals statewide by requiring permits for use of water supply systems, including permits to enter into contracts for a supply of water. 6 NYCRR 601.3. Generally, local municipalities have existing permits for specified quantities of water; some municipalities that do not currently consume their maximum allotted quantity have entered into agreements to sell the excess water to gas companies.

In the Susquehanna River Basin and the Delaware River Basin, two Commissions—the Susquehanna River Basin Commission (“SRBC”) and Delaware River Basin Commission (“DRBC”)—established by compacts between the respective states and the United States, regulate water withdrawals. The SRBC and DRBC have developed regulations, policies, and procedures to characterize existing water use and track approved withdrawals. Each uses a permit system and approval process to regulate existing water usage in their respective basins. In the SRBC, for example, regulations require many projects to show that a minimum flow in the freshwater body is maintained in order to receive SRBC approval. Even if a project with passby flow requirements has been approved, withdrawal must cease if the minimum flow is not maintained. SGEIS §6.1.1.7. They also have monitoring and reporting requirements once a withdrawal is approved.

In response to increased hydraulic-fracturing in Pennsylvania, SRBC recently changed its water withdrawal regulations. The changes did the following:

- Established a new Approval By Rule process, similar to the existing rule in 18 CFR § 806.22(e), to regulate all consumptive use activity related to the development of the Marcellus and Utica Shales, not just consumptive use by public water supply systems;
- Regulate natural gas well development projects on a drilling pad basis;
- Allow drilling operators to use a wide range of water for hydrofracking, including wastewater treatment facility discharge, mine pool water and other lesser quality waters, public water supply sources, and other withdrawals separately approved by SRBC;
- Require metering, daily use monitoring and quarterly reporting, and compliance with SRBC’s consumptive use mitigation requirements in order for water withdrawal applications to be
• Require accounting for production fluids and brines utilized for subsequent fractures. These fluids, however, are not included in the consumptive use calculation in order to incentivize re-use;
• Require projects to demonstrate compliance with state and/or federal law for the treatment and disposal of flow-back or produced fluids, including brines; and
• Limit the new administrative approvals to a term of five years.

See SRBC Final Rulemaking for Natural Gas Well Development Projects (with link to Federal Register pdf), available at http://www.srbc.net/programs/projreviewmarcellus.htm; specific section numbers within 18 CFR Part 806 can be found in the Federal Register pdf and read in full text from http://www.law.cornell.edu/cfr/.

DRBC, like SRBC, has asserted jurisdiction over water withdrawals for drilling in its watershed. Although DRBC has begun considering general concerns such as flow rates and water pollution, it has not yet begun a rulemaking process for Marcellus Shale water withdrawals like SRBC has.

**Q: Where will gas companies obtain water?**

**A:** The DEC predicts that gas companies will obtain water from surface water away from the well site, such as rivers and streams, or through wells drilled into groundwater aquifers. SGEIS §6.1.1

New York State uses classifications provided in section 2.4.1 of the SGEIS. Water quality standards established by state regulations can be a check on where freshwater body withdrawals occur, because the uses are dependent upon sufficient water in the stream to support the specified use. SGEIS §6.1.1.2 Also, standards prohibit any alteration in flow that would impair a fresh surface water body’s designated best use. 6 NYCRR 703.2, available by searching Title 6 Environmental Conservation from the “NYCRR” link at the top of the page at http://www.dos.state.ny.us/info/nycrr.htm.

**Q: How can gas drillers reduce water consumption?**

**A:** Gas drillers can reduce the amount of fresh water that fracking operations consume by using other types of water, including:

• Flowback fluids that have resurfaced from previous fracking;
• Discharge from water treatment facilities; and
• Briny water supplies.

SRBC’s new regulations incentivize gas companies to reuse flowback fluids by allowing companies to not count flowback fluids as consumptive water use. Companies must still account for the reused fluids, but are not subject to the mitigation regulations that would apply if the fluids were not recycled. SRBC Final Rulemaking for Natural Gas Well Development Projects (with link to Federal Register pdf), available at http://www.srbc.net/programs/projreviewmarcellus.htm.

**Q: Will existing water needs be protected in the event of a water shortage?**

**A:** The DEC can deny or limit a permit for a water supply contract if a water shortage threatens drinking water supplies. 6 NYCRR 601.3

Likewise, the SRBC can deny water withdrawal applications or limit approval if withdrawal would have significant adverse impacts to the Susquehanna River Basin. The SRBC has the 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. Possible impacts include reduced stream flow levels, impacts to aquatic ecosystems, impacts to downstream wetlands, and aquifer depletion. SGEIS §7.1.1.3

**Water Quantity Recommendations**

The DEC should:
- Encourage the use of closed loop systems for drilling fluids to reduce the risks of spills and also to reduce the amount of water used and subsequently needing to be transported and disposed.
- Require drilling companies to reuse fracturing flowback fluids to reduce the quantity of fresh water pollution that results from the drilling process.
- Create incentives for drilling companies to use other non-potable water for fracturing operations, such as discharge from water treatment facilities and briny water.
- Take into consideration that most areas where drilling takes place do not have public water supplies but rather rely on public wells. The DEC should be required, as a condition to approving a drilling permit, to test water wells in each spacing unit, before, during and after drilling.

The DEC and SRBC should:
- Closely monitor groundwater and stream flow levels to ensure adequate drinking water supplies for the public.
- Hire adequate staff to ensure effective water level monitoring.
- Deny or limit water withdrawal permits for gas drilling operations if public water supplies are threatened.

DRBC should review its water withdrawal regulations with protection of adequate water supplies in mind.

**Water Quality**

**Q:** What additives make up fracking fluid?

**A:** Fracking fluid is typically comprised of more than 98% fresh water and sand, with chemical additives, such as bactericides, surfactants, acids, breakers, proppants, clay stabilizers, corrosion inhibitors, crosslinkers, friction reducers, gelling agents, iron controls, scale inhibitors, among others, comprising 2% or less of the fluid. The composition of these fluids will vary from one geologic formation to another but the range of additive types for potential use remains the same. SGEIS §5.4

**Q:** What kind of access do agencies and landowners have to fracking fluid formulas?

**A:** The DEC retains authority to require full chemical disclosure with well permit applications that propose the open use of open surface impoundments. For those permits not proposing open surface impoundments, the DEC proposes to require identification of additive products and proposed percent by weight of water, proppants, and each additive. There has not been any potential impact identified other than impoundment emissions that requires full compositional disclosure to the DEC for such water-based solutions. SGEIS §8.2.1.2. Additionally, the DEC will not issue a well permit to operators until the agency has reviewed the planned fracturing procedures and products. SGEIS §8.2.2

The proposed hydraulic fracturing product additives for use in NYS and used for fracturing horizontal
wells in other states contain similar types of chemical constituents as the products used for many years in vertical wells. However, the total amount of water and additives used for horizontal wells exceeds considerably the amount used in vertical wells. This suggests potentially larger environmental impacts associated with horizontal drilling and fracturing than with vertical well drilling. SGEIS §5.4.3.1 In light of these concerns, and in addition to the DEC controls listed above, the DEC refers to further mitigation measures regarding potential pollution and contamination risk of additives to groundwater:

• Chapter 5 of the draft SGEIS describes specialized containers to be used for the delivery and containment of hydraulic fracturing additives until they are mixed with water and proppant and pumped into the well and also establishes time limits for additives present at the site.

• Specific secondary containment requirements will be included in supplementary well permit conditions for high-volume hydraulic fracturing on a site-specific basis if the proposed location or operation raises a concern about potential liquid chemical releases that is not sufficiently addressed by the GEIS, SGEIS, inherent mitigation factors, and well pad setbacks. The criteria to be evaluated will include consideration of factors such as the nature and classification of the liquid, qualitative soil permeability, relative topographic position, engineered or designed containment controls, or other physical factors specific to the application. SGEIS §7.1.3.3

• Best Management Practices will also be employed relative to additive containers, mixing, and pumping, including, but not limited to some or all of a number of listed protective practices. SGEIS §7.1.3.3

Some gas companies claim that fracking fluid formulas are trade secrets and are exempted from the Freedom of Information Law (FOIL) under Public Officers Law § 87(2)(d), which exempts public disclosure of trade secret information if disclosure would cause substantial injury to the competitive position of the company. In a June 2008 decision by the New York Court of Appeals, the state’s highest court increased the burden on companies that claim that information should be exempted from disclosure because it is a trade secret. In the case, the Court of Appeals changed prior law to require more proof that an information disclosure would substantially injure a company’s competitive advantage. The court stated, “To meet its burden, the party seeking exemption must present specific, persuasive evidence that disclosure will cause it to suffer a competitive injury; it cannot merely rest on a speculative conclusion that disclosure might potentially cause harm.” Markowitz v. Serio, 11 N.Y.3rd 43 (2008).

Q: Where can operators drill wells?

A: Operators’ ability to drill wells in a given location depends on whether the DEC considers drilling on that type of location to have a significant environmental impact. The DEC reviewed the impact of oil and gas drilling on several types of locations, and its findings are contained in the 1992 Final GEIS on the Oil, Gas and Solution Mining Program (“1992 GEIS”), available at http://www.dec.ny.gov/energy/45912.html. These findings are further discussed in the SGEIS as will be mentioned below. The SGEIS states that when the well permit application documents demonstrate conformance with the GEIS, SEQRA is satisfied and no Determination of Significance or Negative or Positive Determination under SEQRA is required. The Department is not proposing to alter its 1992 findings with respect to well locations. SGEIS §3.1.2 They are as follows:

*Any location, when no other permits are required: no significant impact.*

Permits can only be granted if there is no alternative to placement within 100 feet and furthermore if the structure has no impact on the wetlands or if that impact is outweighed by an economic and social need. In the 1992 GEIS, the DEC found that issuing a standard, individual oil or gas well drilling permit anywhere in the state, when no other permits are involved, does not have a significant
environmental impact. SGEIS §3.1.1

Location above an aquifer: no significant impact.
The DEC found that issuing an oil and gas drilling permit for locations above aquifers does not have a significant environmental impact because of special regulations for freshwater aquifer drilling that the DEC has already implemented. SGEIS §3.1.1

Location in a State Parkland or Agricultural District: possible significant impact.
The DEC found that issuance of a drilling permit for a location in a State Parkland or in an Agricultural District may be significant and requires a site-specific SEQRA determination. SGEIS §3.1.1

Location between 1,000 to 2,000 feet from a municipal water supply well: possible significant impact.
The DEC found that issuance of a drilling permit for a location between 1,000 to 2,000 feet from a municipal water supply well may be significant and requires a site-specific assessment and SEQRA determination, and may require a site-specific SEIS. SGEIS §3.2.3

Location less than 1,000 feet from a municipal water supply well: always significant impact.
The DEC found that issuing a drilling permit for locations less than 1,000 feet from a municipal water supply well is always significant and requires a site-specific SEIS addressing groundwater hydrology, potential impacts, and mitigation measures. SGEIS §3.2.3

Location that requires other DEC permits: possible significant impact.
The DEC found that issuing a drilling permit for a location that requires other DEC permits may be significant and requires a site-specific SEQRA determination. SGEIS §3.1.1

State-Owned Lands in the Adirondack and Catskill Forest Preserves:
No drilling will occur here due to the State Constitution’s requirement that Forest Preserve lands be kept forever wild and not be leased or sold. SGEIS §2.3

Other locations:
The Department will continue to exercise its discretion regarding applicability of the above mentioned review process to other public supply wells. SGEIS §3.2.3

Furthermore, the Department proposes site-specific environmental assessments and SEQRA determinations for certain high-volume hydraulic fracturing projects mentioned in 3.2.3 of the SGEIS:

- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed shallower than 2,000 feet anywhere along the entire proposed length of the wellbore.
- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed where the top of the target fracture zone at any point along the entire proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply.
- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed and the fluid disposal plan required by 6 NYCRR 554.1(c)(1) includes use of a centralized flowback water surface impoundment that has not been previously approved by the Department.
- Issuance of a permit to drill the first well when high-volume hydraulic fracturing is proposed on a well pad within 300 feet of a reservoir, reservoir stem or controlled lake.
- Issuance of a permit to drill the first well when high-volume hydraulic fracturing is proposed on well pad within 150 feet of a private water well, domestic-use spring, watercourse, perennial or intermittent stream, storm drain, lake or pond.
• Issuance of a permit to drill when high-volume hydraulic fracturing is proposed and the source water involves a surface water withdrawal not previously approved by the Department that is not based on the Natural Flow Regime Method as described in Chapter 7.
• Issuance of a permit to drill any well subject to Article 23 whose location is determined by NYCDep to be within 1,000 feet of subsurface water supply infrastructure.

SGEIS §8.1.1.1

Q: What kind of groundwater protections are already in place for gas drilling?
A: Private Water Well Testing:
Testing will take place before drilling and at established intervals after drilling or hydraulic fracturing operations. SGEIS §7.1.4.1

Well casing and cementing:
Regulations regarding well casing already exist and will continue to be in place. The DEC’s well casing and cementing practices require drillers to implement various technical precautions to isolate a drilling operation from groundwater. For example, freshwater aquifers must be sealed behind cemented steel pipe before any fluid can be released into the bore, and surface casing must extend at least seventy-five feet beyond the deepest freshwater zone or seventy-five feet into bedrock. However, more stringent requirements are implemented with respect to primary and principal aquifers, requiring for example, that surface casing extend at least 100 feet below the deepest freshwater zone and at least 100 feet into bedrock. SGEIS §7.1.4.2

Well plugging:
Standards for well plugging also already exist as part of New York’s oil and gas regulations and are crucial to the continued safety of water supplies in the decades after a well has been depleted or abandoned. In the Final Scope, the DEC describes well plugging standards:

“Any unsuccessful well or well whose productive life is over must be properly plugged and abandoned, in accordance with Department-issued plugging permits and under the oversight of Department field inspectors. Proper plugging is critical for the continued protection of groundwater, surface water bodies and soil. Financial security to ensure funds for well plugging is required before the permit to drill is issued, and must be maintained for the life of the well.

When a well is plugged, downhole equipment is removed from the wellbore, uncemented casing in critical areas must be either pulled or perforated, and cement must be placed across or squeezed at these intervals to ensure seals between hydrocarbon and water-bearing zones. These downhole cement plugs supplement the cement seal that already exists at least behind the surface (fresh-water protection) casing and above the completion zone behind production casing.

Intervals between plugs must be filled with a heavy mud or other approved fluid. For gas wells, in addition to the downhole cement plugs, a minimum of 50 feet of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or brine from the wellbore. This plug also serves to prevent wellbore access from the surface, eliminating it as a safety hazard or disposal site.” SGEIS §5.17

Additional Supplementary Permit Conditions for High-Volume Hydraulic Fracturing:
These will require private water well testing, pit construction and liner specifications for well pad reserve pits, requirement that tanks be used to contain Flowback water on site, appropriate secondary containment measures, removal of fluids within specified time frames, use of appropriate pressure-control procedures and equipment, requirement for notification to DEC prior to cementing surface casing, requirements for cement to surface and a cement bond log, use of a pre-frac form to certify
wellbore integrity prior to fracturing, and pre-fracturing pressure testing of casing from surface to top of treatment interval. SGEIS §7.1.5

**Q:** What kind of surface water protections are already in place for gas drilling?

**A:** Surface water protections are extremely important in gas drilling, primarily once fluid has flowed back as the mixed fracking fluid. Before fracturing, “additives remain at the wellsite in the containers and on the trucks in which they are transported and delivered.” The Department of Transportation’s regulations indicate that fresh water, sand and chemical additives are delivered separately to the wellsite. There is no long-term on-site storage of pre-mixed fracturing fluid since fracking fluid is blended once it is pumped into the cased and cemented wellbore. SGEIS §5.6

Storage is key in protecting surface water quality from pollution by flowback fluids. New York currently allows gas companies to use surface evaporation pits, which must be lined and reclaimed with forty-five days after drilling operations have stopped. The DEC proposes in the SGEIS a requirement that Flowback water handled at the well pad be directed to and contained in steel tanks. SGEIS §7.1.3.4

**Q:** What kind of surface water protections are already in place for spills and accidents that may occur during transport of wastes?

**A:** The DEC will require that a *Drilling and Production Waste Tracking Form* be completed and maintained by generators, haulers, and receivers of flowback water. SGEIS §7.1.6.1

In order for a hauler’s Part 364 permit renewal, flowback water may not be spread on roads and must be disposed of at facilities authorized by the DEC. In addition to this permit renewal requirement, haulers must also submit a petition for a beneficial use determination to the DEC prior to the removal of any production brine from the well site. SGEIS §7.1.6.2

Fluid disposal plans must show that pipelines and conveyances will be constructed of suitable materials, maintained in a leak-free condition, regularly inspected and operated using spill control and stormwater pollution prevention practices. SGEIS §7.1.6.3

**Q:** How will NORMs affect water quality?

**A:** Some shales like the Marcellus Shale contain Naturally Occurring Radioactive Materials ("NORMs"), which may come to the surface with flowback fluids. Gas companies and environmentalists disagree on the extent to which NORMs will surface with flowback fluids and whether they will surface in large enough quantities to pose a threat to human health and the environment. If NORMs surface in large enough quantities, the issue of finding treatment facilities that can handle the NORMs will be very important.

In NYS, the handling of radioactive material is regulated. The State Sanitary Code and the Industrial Code include requirements for radioactive materials licensing. The DEC regulates requirements for environmental discharges, waste shipment and disposal, and environmental cleanup. The overall licensing requirement for radioactive material states that “no person shall transfer, receive, possess or use any radioactive material except pursuant to a specific or general license….” However, any person is exempt from the requirements to the extent that such person transfers, receives, possesses or uses products or materials containing radioactive material in concentrations and quantities not in excess of those listed in the accompanying tables. The discharge of radioactive material into the environment is regulated by the DEC. SGEIS §7.8.2
In light of the variability in NORM content that appears to occur both between wells in different portions of the formation and at a given well over time, sampling and analysis will be undertaken to assess whether additional mitigation is needed. Radiological surveys and measurements as well as radiation exposure rate measurements of areas of potential NORM contamination will be conducted in order to determine which gas production facilities may be subject to the licensing and environmental discharge requirements. SGEIS §7.8.2

Q: How is fracking fluid disposed of?
A: Some general regulations apply regardless of the disposal method. First, DEC requires all generators, haulers, and receivers of flowback fracturing fluid to maintain a Drilling and Production Waste Tracking Form. The requirements and detail of this form are similar to those required for medical waste. dSGEIS 7.1.6.2. Second, DEC requires the submission and approval of a fluid disposal plan before it issues a well drilling permit for any operation in which the probability exists that brine, salt water, or other polluting fluids will be produced or obtained during drilling operations in sufficient quantities to be deleterious to the surrounding environment. dSGEIS 7.1.6.3.

Re-use
One option for fluid disposal is re-use either onsite in a tank or lined pit or off-site at a centralized flowback water facility, which can consist of tanks or other engineered impoundments. dSGEIS 5.12.2.1. If the fluids are kept in an on-site facility, DEC must approve the surface impoundment before the well permit application will be complete. DEC will not approve of impoundments within the boundaries of primary and principal aquifers or unfiltered water supplies.

If the fluids are piped to a centralized flowback facility, the piping and conveyances must be described in the fluid disposal plan required by 6 NYCRR 554.1(c)(1) and the Multi-Sector General Permit (MSGP) Stormwater Pollution Prevention Plan (SWPPP). The fluid disposal plan must demonstrate that pipelines and conveyances will be constructed of suitable materials, maintained in a leak-free condition, regularly inspected, and operated using all appropriate spill control and stormwater pollution prevention practices. dSGEIS 7.1.6.3. The Department will apply standards from two of its regulatory programs to review proposed centralized flowback water surface impoundments. First, construction must follow DEC’s Guidance for Design of Dams if the impoundments meet dam safety permitting criteria based on height and storage capacity. Second, the impoundments must satisfy the requirements established for solid waste management facilities in 6 NYCRR Part 360. Although the flowback fluids are not solid wastes, apparently their characteristics compare qualitatively with landfill leachate regulated under Part 360. dSGEIS 7.1.7. Typical design for flowback impoundments includes:

- A liner system with an upper (primary) 60-mil liner of high density polyethylene (HDPE) geomembrane and a lower (secondary) 40-mil liner of HDPE geomembrane with a geocomposite layer underneath.
- A geocomposite layer between the two geomembrane liners.
- A leak detection system installed in the interstitial space between the two liners within a trench placed below the impoundment at its lowest point of elevation.

dSGEIS 5.12.2.1.

Disposal
Some general regulations apply regardless of the disposal method. First, each DEC well permit requires fluids to be removed from the well site by a hauler with a 6 NYCRR Part 364 Waste Transporter Permit. Part 364 details requirements associated with the permit, such as identifying the
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type of waste transported, including any testing that may be necessary to determine whether or not the waste is hazardous, and ensuring that the waste is delivered to an authorized waste receiving facility that can treat the waste. Second, flowback water and production brine are considered industrial wastewater. All wastewater dischargers must have a State Pollutant Discharge Elimination System (SPDES) permit from DEC, a process that is delegated by EPA. A SPDES permit includes specific monitoring requirements and discharge limitations, which are the maximum allowable concentrations for various physical, chemical, and biological parameters.

Disposal methods include:
- Disposal wells
- Municipal sewage treatment facilities
- Out-of-state industrial treatment plants
- Other options

*Disposal wells:*
Disposal wells are usually wells that were drilled but never produced any gas. The disposing company will treat the fracking fluid and inject it into the well through a one-way valve, so that it does not return to the surface. A disposal well requires site-specific SEQRA review, a SPDES permit, and a UIC permit. DEC may impose additional monitoring requirements or discharge limits based on the site-specific review. The SEQRA review considers the following topics:

- Distance to drinking water supplies or sources, surface waterbodies, and wetlands,
- Topography, geology, and hydrogeology,
- The proposed well construction and operation program,
- Water quality analysis of the receiving stratum for total dissolved solids (TDS), chloride, sulfate, and metals,
- Effluent limits for injectate constituents and potential applicability of 6 NYCRR 703.6 groundwater effluent limits or the groundwater effluent guidance values listed in Division of Water Technical and Operational Guidance Services (TOGS) 1.1.1, and
- Potential requirement for upgradient and downgradient monitoring wells installed in the deepest identified GA or GSA potable water aquifer.

dSGEIS 7.1.8.2.

Neither EPA nor DEC will issue a permit without a demonstration that injected fluids will remain confined in the disposal zone and isolated from fresh water aquifers. After the fracking company obtains UIC and SPDES permits, it must also obtain a well permit from the DEC’s Division of Mineral Resources if the company is drilling or converting a well deeper than 500 feet for brine disposal. dSGEIS 5.13.3.1.

*Municipal sewage treatment facilities:*
Municipal sewage treatment facilities, also known as Publicly Owned Treatment Works (POTWs), must have a DEC-approved pretreatment program for accepting any industrial waste, in accordance with 6 NYCRR Part 750-2.9(b), National Pretreatment Standards, which incorporates 40 CFR Part 403, General Pretreatment Regulations for Existing and New Sources of Pollution. These regulations require facilities to perform analyses showing that they can handle the waste without disrupting their system or the receiving waters as well as to notify DEC if they plan to accept new waste.

DEC may modify the facilities’ SPDES permits to insure water quality standards. The SPDES permits for POTWs require a headworks analysis, which must be in accordance with DEC’s Division of Water (DOW) TOGS 1.3.8, New Discharges to Publicly Owned Treatment Works. DOW will consider whether:
• The POTW has adequately evaluated the effects of the proposed discharge on facility operation, sludge disposal, effluent quality, and facility health and safety;
• The discharge will result in the release of a substance subject to effluent limits, action levels, or other monitoring requirements in the POTW’s SPDES permit; and
• The proposed discharge contains any Bioaccumulative Chemicals of Concern or persistent toxic substances that may be subject to SPDES limits or other DEC permit requirements.

Specific information about the fracking fluids, such as chemical makeup and aquatic toxicity, will be required for DOW review. The existence of proprietary material can be noted in the analysis, but the dSGEIS emphasizes that “in no circumstance shall a fracturing additive be approved or evaluated in a headworks analysis without aquatic toxicity data.” dSGEIS 7.1.8.1. The high concentration of TDS in flowback fluid must be considered in the headworks analysis, as such concentrations may prevent treatment in a municipal system. Appendix C of TOGS 1.3.8 further describes the headworks analysis requirements.

An overview of POTWs and headworks analyses is available at: http://www.dec.ny.gov/chemical/8728.html.

Out-of-state industrial treatment plants:
New York State does not yet have industrial facilities that can handle wastewater from high-volume hydraulic fracturing. Table 5.14, dSGEIS at 5-121, lists out-of-state plants that are proposed to receive flowback water from New York. Similar facilities constructed in New York would require a SPDES permit.

Other options:
Other options for fracking fluid disposal include:
• Disposal at existing or new private in-state wastewater treatment facilities,
• Injection for enhanced recovery in oil fields, or
• Road spreading, which is discussed below.

Evaporation pits are common in other states but are not expected to be used in New York due to the state’s low evaporation rates.

Under current New York law, used fracking fluid is considered an industrial waste product, not a hazardous waste product. In addition, two federal laws regulating hazardous substances, the Resource Conservation and Recovery Act (RCRA) and the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), generally exempt gas waste removed from the well, such as fracking fluid. Classification of used fracking fluid as a hazardous waste would impose more stringent waste requirements on gas companies than the DEC currently requires.

Q: Is road spreading allowed as a disposal method for used fracking fluids?
A: In January 2009, the Division of Solid and Hazardous Materials (DSHM), responsible for oversight of the Part 364 program, released a notification to haulers applying for, modifying, or renewing their Part 364 permit that fracturing fluids obtained during flowback operations may not be spread on roads and must be disposed of at facilities authorized by the Department or transported for use or re-use at other gas or oil wells where acceptable to the Division of Mineral Resources. The notification specified that only production brines may be used in road spreading and that any entity applying for a Part 364 permit or permit modification to use production fluid for road spreading must submit a petition for a beneficial use determination (BUD) to the Department. The petition must include
analytical results from a NYSDOH laboratory sample for components ranging from calcium to benzene. DEC may require additional analyses depending on the results of this sample. For Marcellus production brine, DEC will add a radioactivity scan as described in dSGEIS 7.1.8.1. The BUD will be denied if levels indicate a potential public exposure concern. DEC must issue the BUD and Part 364 permit prior to the removal of any production brine from a well site. dSGEIS 7.1.6.2.

Q: Is hydrofracking exempt from the Safe Drinking Water Act?
A: The Safe Drinking Water Act (SDWA) contains provisions for the federal Underground Injection Control (UIC) program, which requires federal permits for subsurface injection of wastes that could harm drinking water supplies. Section 322 of the Federal Energy Policy Act of 2005 (2005 Energy Act) amended SWDA to exempt hydraulic fracturing from the definition of underground injection. This exemption has been termed the “Halliburton Loophole” because Halliburton patented the hydrofracturing process. Therefore, the act of hydrofracking, where underground rock formations are fractured to allow natural gas extraction, is exempted from the UIC program because it does not involve waste storage. However, the underground storage of flowback fracking fluid is not exempted and is still subject to federal UIC regulatory controls.

Both the House and the Senate have developed versions of the FRAC Act — the Fracturing Responsibility and Awareness of Chemicals Act of 2009 (HR 2766 or S 1215). Among other things, this legislation would repeal the hydrofracking exemption. On June 9, 2009 the House version was referred to House Committee on Energy and Commerce and the Senate version was referred to the Committee on Environment and Public Works.

In addition, Congress included a measure in the Interior and Environment Appropriations Bill for fiscal year 2010 that requires EPA to fund a scientific, peer-reviewed study of the relationship between hydraulic fracturing and drinking water.

Q: What regulations exist to ensure drilling companies properly close and plug drill sites once production ceases?
A: DEC must issue a plugging permit to a gas company before plugging can begin, and the issuance of this permit is considered a Type II action under SEQRA, which means it does not require an environmental impact statement. A DEC inspector also must oversee the plugging process. The DEC has very specific provisions that must be met to ensure that gas companies properly close and plug wells, which is essential to the long-term protection of water quality and surface environmental quality of the site. Some plugging provisions can be found in 6 NYCRR 555.5, which details plugging methods, procedures, and reports.

Additionally, gas companies must provide financial security for well plugging and drill site closure and leave it in escrow. 6 NYCRR 551.5. This financial obligation ensures that money will be available for closure if, at the time, a gas company no longer exists or is unable to pay for a well plugging.

**Water Quality Recommendations**

To protect water quality during gas production in New York State, the DEC should:
- Define fracking flowback fluids as hazardous waste rather than industrial waste.
- Release fracking fluid formulas to property owners and tenants with land adjacent to or including a well site as well as to emergency personnel.
Sediment and Erosion

Q: What effect do gathering lines have on sediment and erosion?
A: Gathering lines are small, low-pressure pipelines that transport gas from a production site to a processing location. Gathering line construction has the potential to cause erosion and sediment problems. Due to the steep increase in drilling expected throughout New York State in the near future, extensive networks of gathering lines will soon cross the landscape. The use of multi-well pads has the potential to decrease the number of gathering lines needed and the resulting erosion. Sediment problems can also be avoided or mitigated with good planning and the assistance of soil and water conservation districts. Early cooperation between gas companies and soil and water specialists will be the most efficient, cost-effective way to prevent future hydrological problems across the state. As discussed below, DEC has very little authority over gathering lines, so their siting, construction, and environmental impacts are discussed very minimally in the dSGEIS.

Q: Who regulates gathering lines?
A: The New York Public Service Commission (PSC) is the primary government body that regulates gathering lines, so there is no SEQRA review of line siting or construction. 6 NYCRR 617.5(e)(35). Article VII of the New York Public Service Law (PSL), “Siting of Major Utility Transmission Facilities,” guides PSC’s permitting process. PSC must conduct a full environmental impact review of the siting, design, construction, and operation of major intrastate electric and natural gas transmission facilities in New York State. The Commission gives notice of potential gathering line construction to the municipality where lines will be built, and people from that municipality, as well as other concerned individuals, may comment on gathering line siting. The Department of Public Service (DPS) is responsible for representing the public interest in this process, and thus employs experts, engineers, and economists to consider a project’s effects on local residents and the general public in New York State. dSGEIS 5.16.8.1. More information on this may be found in this document’s section on Public Participation in Pipeline Siting and Construction.

For gathering lines less than 125 psig (pounds per square inch), DEC is only able to influence siting where the lines interfere with environmentally sensitive areas that require permits in addition to the well permit. DEC can only influence permitting for federally delegated programs such as Title V of the Clean Air Act and SPDES under the Clean Water Act. For lines over 125 psig, DEC only has permitting authority. dSGEIS at 5-135.

Municipalities are also preempted from regulating any type of transmission line except where there is another applicable state law mandating that the municipality act to protect employees engaged in construction and operation of the line and the municipality has received notice that a construction application has been filed. NY Pub. Serv. § 130.

Q: What role could soil and water conservation professionals have in the gathering line siting and construction process?
A: Soil and water conservation professionals can help ensure intelligent, preventive gathering line construction by using the current regulatory system to participate in the Public Service Commission’s public siting process, as mentioned above and in detail in this document’s section on Public Participation in Pipeline Siting and Construction.

Another way that soil and water conservation professionals could help guarantee smarter gathering line construction could be to change the current regulatory structure so that the DEC directly oversees environmental review of gathering line siting in addition to the PSC. Soil and water conservation
professionals could submit comments to DEC on the dSGEIS, arguing that because of the scale of the upcoming gas production in New York State, gathering line construction should presumptively be considered a disturbance to environmentally sensitive areas and that gathering lines should be viewed in the aggregate when determining their environmental impact. If this argument succeeded, gathering lines would be subject to the DEC’s regulatory system, which is perhaps more familiar to professionals than are the PSC’s environmental review methods. However, by using the Commission’s existing comment process, conservation professionals might be able to work more closely with companies building gathering lines. This could potentially give soil and water conservation professionals flexibility in finding creative solutions to sediment and erosion challenges posed by gathering line construction.

It is worth noting that the PSC’s and the DEC’s environmental review processes are very similar in content. By encouraging the DEC to view gathering lines as warranting DEC review as well, however, the chances of negative environmental impacts from line siting could decrease.

Soil and water conservation professionals have specialized knowledge about specific measures to mitigate erosion problems arising from pipeline construction. As a result, development of best management practices (BMPs) for gathering lines would benefit both conservation professionals and the gas industry.

Q: What are some existing sediment and erosion controls that apply to the gas industry?
A: One example of existing sediment and erosion controls is the DEC’s Stream Disturbance Permit, which is required for any well site activity that disturbs the bed or banks of a protected stream. Additionally, DEC Article 15 permits may be required to construct water withdrawal infrastructure such as standpipes. These regulations may be relevant for gas companies withdrawing water directly from surface bodies, rather than trucking water to the well site for hydrofracking. Under DEC regulations, a gas company’s failure to adhere to an erosion and sedimentation control plan is a violation and may result in the DEC imposing fines or penalties or immediately suspending drilling operations. [Do companies have to develop SWPPPs for pipeline construction?]

Q: Did the Energy Policy Act of 2005 exempt gas companies from the Clean Water Act?
A: The answer is unclear. The Clean Water Act requires all facilities that discharge pollutants from any point source into surface waters to obtain National Pollutant Discharge Elimination System (NPDES) stormwater permits. Prior to the 2005 Energy Act, section 402(l)(2) of the Clean Water Act exempted “gas exploration, production, processing or treatment operations, or transmission facilities” from the NPDES permit requirement, as long as the stormwater discharges were uncontaminated. The requirement for uncontaminated discharges was codified in 40 C.F.R. § 122.26(c)(1)(iii), which said that the discharges must not contribute to a violation of a water quality standard. Section 503(24) of the CWA defined the quoted phrase above as “all field activities or operations associated with exploration, production, processing, or treatment operations, or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment.” Section 323 of the 2005 Energy Act amended section 503(24) of the CWA to include construction as an associated activity or operation. While not changing the statutory language in section 402(l)(2) of the CWA, the 2005 Energy Act influenced the section’s interpretation.

On June 12, 2006, EPA published a final rule to address the new provisions in the 2005 Energy Act. The rule attempted to clarify 40 C.F.R. § 122.26(c)(1)(iii) by saying that a “water quality standard violation for sediment alone does not trigger a permitting requirement.” The Natural Resources Defense Council sued EPA, claiming that the rule went beyond the mandates of section 402(l)(2) of the CWA and the 2005 Energy Policy Act amendments — essentially that sediment still could
constitute contamination and a violation of a water quality standard. On May 23, 2008, the U.S. Court of Appeals for the Ninth Circuit held that EPA’s rule was unlawful. On November 3, 2008, the Ninth Circuit denied EPA’s petition for a rehearing and vacated EPA’s rule. As a result, the effective requirements are the regulations in place prior to EPA’s 2006 rule as well as the 2005 Energy Act exemptions.

Regardless of federal exemptions, the DEC, through SPDES permits, has authority to require appropriate erosion and sedimentation controls at all well sites, regardless of size. The absence of a stormwater permit requirement on a federal level, however, means that New York State will be the sole enforcer and the only source of remedies in case of a violation.

**Resources**

**Q:** What power do local municipalities have to enforce sediment and erosion controls for gas drilling operations?

**A:** Under existing New York law, local municipalities do not have authority to manage gas drilling operations except for jurisdiction over local roads and real property taxes. ECL § 23-0303(2). As discussed above, municipalities also do not have authority to manage gathering lines. NY Pub. Serv. § 130.

Although local municipalities have very little power to dictate gas drilling operations, their power to control gas companies’ use of local roads under Title 8 of New York State’s Vehicle and Traffic Law is important. As documented in the appendix on environmental and community impacts, gas companies will use local roads extensively for heavy drilling equipment and for numerous, around-the-clock truckloads of water, chemicals, diesel, and wastes coming from and going to well sites. The dSGEIS encourages local governments to be proactive in exercising their authority under Title 8. Such authority includes the ability to conduct a road system integrity study to potentially assess fees for maintenance and improvements. Supplementary permit conditions for high-volume hydraulic fracturing will require the site operator to submit to DEC, prior to site disturbance and for informational purposes only, a copy of a road use agreement between the operator and municipality. If there is no road use agreement, the operator must file a trucking plan with DEC, along with documentation of its efforts to reach a road use agreement. Sample provisions of a road use agreement or trucking plan include:

- Route selection to maximize efficient driving and public safety,
- Avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods,
- Coordination with local emergency management agencies and highway departments,
- Upgrades and improvements to roads that will be traveled frequently for water transport to and from many different well sites,
- Advance public notice of any necessary detours or road/lane closures,
• Adequate off-road parking and delivery areas at the site to avoid lane/road blockage, and
• Use of rail or temporary pipelines where feasible to move water to and from well sites.

SGEIS 7.11.

Sediment and Erosion Recommendations

• Gathering line siting and construction should be considered as presumptively having a significant adverse impact on the environment because of the aggregate impact that gathering lines will have on the soil and hydrology of the Marcellus Shale region. Such a determination would necessitate SEQRA review.
• Soil and water conservation professionals should utilize the existing process for public participation in the Public Service Commission’s permitting process for gathering line siting to encourage wise placement of lines.
• Soil and water conservation professionals should encourage DEC that an investment in enforcement staff is necessary to prevent future widespread sediment and erosion problems that could result from unchecked violations by gas companies. Examples of the future monetary costs that would be required to repair erosion and sediment problems caused by unenforced violations would be especially helpful in arguing this need to the DEC.
• Local municipalities should use their power over local roads to tax gas companies or otherwise require them to repair the wear that they will impose on the roads.
• The possibility of restoring federal oversight under the Clean Water Act and for giving local governments more of a role in the permitting process should be explored.
State Environmental Quality Review Act (SEQR)

Background

The basic purpose of State Environmental Quality Review Act (“SEQR”) is to incorporate the consideration of environmental factors into the existing planning, review and decision-making processes of state, regional and local government agencies. SEQR is the controlling law in determining whether gas companies must issue an environmental impact statement before obtaining a permit from the DEC.

By understanding the SEQR process, one will be able to determine whether gas companies will have to issue environmental impact statements. Environmental impact statements (“EIS”) help one determine what the impacts of drilling will be on the landscape. An EIS provides a means for agencies, project sponsors and the public to systematically consider significant adverse environmental impacts, alternatives and mitigation. An EIS facilitates the weighing of social, economic and environmental factors early in the planning and decision-making process. A draft EIS is the initial statement prepared by either the project sponsor or the lead agency and circulated for review and comment. There are three different kinds of EIS - a "generic," a "supplemental" or a "federal.” Under New York state law, actions that will have an impact on the landscape need to comply with the SEQR, which requires an EIS to complete the SEQR review process before they are approved by the DEC.

SEQR Process and Factors

The SEQR process evaluates the environmental impact of certain activities on the land designated for gas drilling. Natural gas drilling is likely to have many effects on the landscape. Thus, such land must undergo the SEQR process in certain circumstances.

Most activities or projects that are proposed by a unit of local government or state agency and all permits from a New York state agency are required to undergo an environmental impact statement under 6 NYCRR Part 617 State Environmental Quality Review (“SEQR”). “SEQR requires the sponsoring or approving governmental body to identify and mitigate the significant environmental impacts of the activity it is proposing or permitting.” Based on this requirement, DEC would have to identify and mitigate significant environmental impacts of the gas drilling for which it would be issuing permits for in the Marcellus Shale.

Section 617.1(c) of SEQR states that all agencies are required to “determine whether the actions they directly undertake, fund or approve may have a significant impact on the environment, and, if it is determined that the action may have a significant adverse impact, prepare or request an environmental impact statement.” Based on this statutory language, it is quite clear that gas drilling companies will only be required to issue an EIS if the DEC determines that drilling will have a significant adverse impact. If the DEC makes this finding, then the companies will have to prepare an EIS. However, if the DEC feels that the drilling will not have a significant adverse impact on the environment, then the companies will not have to issue an EIS.

SEQR lists several factors that an agency must examine to determine whether a proposed activity may have a significant adverse impact on the environment in § 617.7. Thus, the agencies in New York State

are not left to determine what kinds of actions may have an adverse impact on the environment in an ad hoc manner. The numerous criteria that SEQR lists are located in § 617.7(c).

Activities are defined under SEQR as either Type I, Type II or Unlisted. Type II actions do not require an EIS, determination of significance or findings statements. § 617.3(f) SEQR. Section 617.4 of SEQR lists several actions that fall under the category of Type I, which are then more likely to require an EIS filing than unlisted actions. Section 617.4’s Type I list is not exclusive – other proposed activities may be identified by an agency as having the potential to have a significant adverse impact on the environment and require an EIS. § 617.4(a)(1). However, the fact that an action or project has been listed as a Type I action carries with it the presumption that it is likely to have a significant adverse impact on the environment and may require an EIS. § 617.4(a)(1).

For all individual acts that are identified as either Unlisted or Type I, the agency determining significance must “compare the impacts which may be reasonably expected to result from the proposed action with the criteria listed in subdivision 617.7(c) of this Part [SEQR].” § 617.4(a)(1). Some natural gas drilling companies will likely seek large areas of land to lease from the state in order to pursue natural gas drilling in the Marcellus Shale. According to § 617.4(b)(4), “the acquisition, sale, lease, annexation or other transfer of 100 or more contiguous acres of land by a state or local agency” is a Type I action. This identification should greatly increase the chance that gas companies’ efforts to lease large tracts of land from the government will require them to issue an EIS. If natural gas drilling will require the physical alteration of 10 acres or more then it is identified as a Type I action under § 617.4(b)(6)(i). Another activity that natural gas drilling may involve and thus fall under a Type I action are actions “that would use ground or surface water in excess of 2,000,000 gallons per day.” § 617.4(b)(6)(ii). These categories affect how the SEQR will be required to issue environmental impact statements.

The current regulations in place at the DEC are not inclusive enough as to what types of natural gas drilling will have a significant adverse impact on the environment.

The Generic Environmental Impact Statement (GEIS)

Q: What is the Generic Environmental Impact Statement (GEIS)?
A: The Generic Environmental Impact Statement was a document most recently finalized 1992 and issued by the Department of Environmental Conservation (“DEC”) to evaluate its gas and oil regulatory program. Generic EISs and their findings should set forth specific conditions or criteria under which future actions will be undertaken or approved, including requirements for any subsequent SEQR compliance. This may include thresholds and criteria for supplemental EISs to reflect specific significant impacts, such as site specific impacts, that were not adequately addressed or analyzed in the generic EIS. The GEIS is relevant because it sets statewide factors that are applicable for SEQR review of issuing permits for various types of drilling.

Q: What is the history of the GEIS and why is it being supplemented?
A: The GEIS is currently in the process of being reformed in order to address gaps to the 1992 Final Generic Environmental Impact Statement (fGEIS) and address all of the potential environmental affects created by drilling in the Marcellus Shale. There are five steps of New York’s review and evaluation process, three of which, at the time of this writing have already occurred. Step four and five result from the Draft Supplemental Generic Environmental Impact Statement (dSGEIS). Currently, the public is commenting and reviewing the dSGEIS, which will be used to create the final SGEIS. The fifth and final step, which has yet to occur, will resulting in the Final Supplemental Generic Environmental Impact Statement (“fSGEIS”), along with a Findings Statement, is issued.
from public comments, additional information and responses to comments.

The draft SGEIS supplements the existing Generic Environmental Impact Statement (GEIS) and analyzes the range of potential impacts of shale gas development using horizontal drilling and high-volume hydraulic fracturing. The draft SGEIS outlines safety measures, protection standards and mitigation strategies that operators would have to follow to obtain permits.

**Q: What are the DEC’s main objectives issuing the supplemental GEIS?**

**A:** The DEC wants to analyze the range of potential impacts of shale gas development using horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale by addressing the following:

- Water withdrawals;
- Ground water impacts associated with well drilling and construction
- Transportation of water to site;
- Use of additives in the water to enhance the hydraulic fracturing process;
- Space and facilities required at well site to ensure proper handling of water and additives;
- Removal and disposal of fracking fluids;
- Noise, visual, and air quality impacts; and
- Cumulative and community impacts.

**Q: What are some of the potential criticisms of the supplemental GEIS?**

**A:** The following list is not exhaustive and commentators are welcome to submit additional critiques. Here are some criticisms:

- The period of sixty days was not adequate for the public to adequately digest the supplemental GEIS and make comments.
- Commitment not to reopen clear deficiencies of 1992 GEIS.
- Vague or absent descriptions of methodologies of how studies and analysis will be conducted.
- Refusal to assess the impacts of associated pipelines, transmission lines, compressor stations, or accidental spills or emissions because these impacts are allegedly not within the division’s jurisdiction.
- Most deficient in the areas of cumulative impacts, risk assessment, air quality, staffing issues, significant habitats, community impacts, best industry practices and public participation.

**State Environmental Quality Review Act (SEQR)**

**Q: What is SEQR and how is it relevant to the SGEIS?**

**A:** The State Environmental Quality Review Act (SEQR) is a New York state law that requires the sponsoring or approving governmental body to identify and mitigate the significant environmental impacts of the activity it is proposing or permitting. The Final SGEIS, to be prepared after consideration of comments received on the draft, will set additional parameters for SEQR review. The DEC will then process and, as appropriate, issue well permits for gas well development using high-volume hydraulic fracturing in accordance with both the GEIS and the SGEIS.

**Q: What are the benefits of SEQR?**

**A:** SEQR provides many benefits to the public, project sponsors and agencies: For example, the public can participate in the SEQR process through:

- Participation in the scoping process for the draft EIS.
- Reviewing SEQR documents and providing comments on them to relevant decision makers at the agency.
- Participation in SEQR hearings on an activity’s / projects environmental impacts,
- Also, as a result of SEQR, agencies are required to provide a clear and supportable record for their decisions.

Q: How is SEQR enforced? What happens if agencies don’t comply with SEQR?
A: SEQR is self-enforcing. Thus, every government agency is responsible to see that it meets its own obligations to comply with the law. In the Marcellus Shale context, the DEC is charged with issuing regulations regarding the SEQR process, but has no authority to review the implementation of SEQR by other agencies.

Since there is no SEQR police, if an agency does not comply with SEQR, citizens or groups who can demonstrate that they may be harmed by this failure may take legal action against the agency. Project approvals may be rescinded by a court and a new review required under SEQR.

Q: What are the steps in the SEQR process? What actions does SEQR require an agency to take?
A: The following chart visually outlines the steps elaborated below

**Step 1: Classify the Action**
- The first step in classifying the action is to decide whether it is subject to SEQR.
  - An action is subject to review under SEQR if any state or local agency has authority to issue a discretionary permit, license or other type of approval for that action.
  - SEQR also applies if an agency funds or directly undertakes a project, or adopts a resource management plan, rule or policy that affects the environment.
  - If the proposed action does not require a discretionary decision, there is no requirement for review under SEQR.
**Step 2: Complete the Environmental Assessment Form (EAF)**

- The second step in classifying an action is to determine whether it is a Type II Action, a Type I Action or an Unlisted Action.
  - Type II actions do not require an EIS, determination of significance or findings statements (§ 617.3(f) SEQR).
  - Section 617.4 of SEQR lists several actions that fall under the category of Type I, which are then more likely to require an EIS filing than Unlisted actions.
  - Section 617.4’s Type I list is not exclusive – other proposed activities may be identified by an agency as having the potential to have a significant adverse impact on the environment and require an EIS (617.4(a)(1)). However, the fact that an action or project has been listed as a Type I action carries with it the presumption that it is likely to have a significant adverse impact on the environment and may require an EIS. (617.4(a)(1)).
- **Type I Actions:**
  - Required to complete a full EAF
  - Requirement may be waived if a draft EIS is prepared and submitted with the application
- **Unlisted Actions:**
  - Do not always require preparation of a full EAF.
  - Agency may require a full EAF if the short EAF will not provide sufficient information, or it may waive the requirement for an EAF if a draft EIS is prepared and submitted with the application.
  - If the option to prepare a full EAF is not exercised, a short EAF must be completed.
  - For Unlisted actions, the short EAF must be used to determine the significance of such actions. However, an agency may instead use the full EAF for Unlisted actions if the short EAF would not provide the lead agency with sufficient information on which to base its determination of significance. The lead agency may require other information necessary to determine significance.

**Step 3: Coordinated Review**

- **Type I Actions:**
  - A coordinated review by each agency is required for all Type I Actions. The involved agency initially receiving an application for approval circulates the completed Part 1 of the full EAF and any other information supplied by the applicant to the other involved agencies. This is opposed to an uncoordinated review which each involved agency acts as a lead agency, and independently conducts an environmental review and determines the significance of the action. If all involved agencies issue negative declarations, the project may go forward. If any of the involved agencies issues a positive declaration, requiring an EIS, all the other determinations of non-significance are superseded and a coordinated review must commence.
- **Unlisted Actions:** Have coordinated / uncoordinated / conditioned negative declaration review options.
  - If any involved agency decides to coordinate the review, or intends to require a draft EIS, that agency must contact the other involved agencies informing them of the decision to coordinate.
- Conditioned Negative Declaration: If during the review of an application and the EAF submitted by an applicant on an Unlisted Action, an involved agency determines that the potentially significant impacts could be eliminated or reduced to a non-significant level through imposed conditions, the agency may consider using the process. Use of this process requires a full EAF and coordinated review.
Step 4: Determining Significance

- The lead agency has 20 calendar days to make its determination of significance.
- If the lead agency finds that it does not have sufficient information to make this determination, it may request that the applicant provide it.
- In determining significance, the lead agency must consider the:
  - Whole action and the criteria [see §617.7(c)];
  - EAF and any other information provided by the applicant;
  - Involved agency input, where applicable; and
  - Public input, if any.

Step 5: Preparing the Draft Environmental Impact Statement (EIS)

- The applicant always has the right to prepare the draft EIS. If the applicant refuses, the lead agency has the option of preparing the draft EIS, having it prepared by a consultant, or terminating its review of the action.
- All draft EIS(s) must include the following elements:
  - Concise description of the proposed action, its purpose, public need and benefits, including social and economic considerations;
  - Concise description of the environmental setting of the areas to be affected, sufficient to understand the impacts of the proposed action and alternatives;
  - Statement and evaluation of the potential significant adverse environmental impacts at a level of detail that reflects the severity of the impacts and the reasonable likelihood of their occurrence, etc.

Step 6: Determining the adequacy of draft EIS for public review.

- Upon receipt of a submitted draft EIS, the lead agency has 45 days to decide whether the EIS is adequate for public review. If the agency decides that the draft EIS is not adequate, it returns the draft EIS to the applicant with a written identification of the deficiencies. The agency has 30 days to determine adequacy of a resubmitted draft EIS.
- If the lead agency determines that the draft EIS is adequate, it issues a Notice of Completion of a Draft EIS.

Step 7: A Notice of Completion of a Draft EIS is issued when the lead agency determines that the draft EIS is adequate.

Step 8: Public Comment Process

- Filing of the Notice of Completion of a Draft EIS starts the public comment period. The period must be a minimum of 30 days, during which all concerned parties are encouraged to offer their comments. The comment period must continue at least 10 days following the close of a public hearing.

Step 9: Determining whether an agency needs to hold a public hearing.

- After the lead agency accepts the draft EIS, it must decide whether to hold a public hearing – a hearing is not mandatory. If a hearing is to be held, the lead agency must prepare and file a Notice of Public Hearing. The hearing cannot start sooner than the 15th day following the Notice of Public Hearing, nor more than 60 days from the date of filing of the Notice of Completion of the Draft EIS. If a public hearing is required under an applicable local or state law, it is not necessary to hold a separate SEQR hearing.

Step 10: Preparation of the final EIS
• The lead agency is responsible for the adequacy and accuracy of the final EIS. The final EIS should be prepared within 45 calendar days after the close of any hearings or within 60 days after the filing of the draft EIS, whichever occurs last. The final EIS must consist of the following parts: the draft EIS, including any necessary revisions and supplements; copies or a summary of the substantive comments received and their sources; and the lead agency’s response to the comments.

**Step 11: Findings – SEQR**

• Each involved agency must prepare its own written findings statement, after a final EIS has been filed and before the agency makes a final decision. The findings of each agency must be filed with all other involved agencies and the applicant at time of adoption.

• A positive findings statement means that the action is approvable after consideration of the final EIS. It also demonstrates that the action chosen is the one that minimizes adverse environmental impacts presented in the EIS and weighs and balances them with the social, economic and other essential considerations.

• If the action is not approvable, a negative findings statement with the reasons for the denial must be prepared. The findings can be finalized no sooner than 10 days following the filing of the Notice of Completion of the Final EIS, and if the action involves an applicant, the lead agency’s findings must be made within 30 days from the filing date.

**SEQR Recommendations**

It is important to urge the DEC to adopt more extensive SEQR regulations that will require this type of drilling activity to undergo an environmental impact process before it is approved by having to issue an environmental impact statement (EIS).

The DEC should:

• Require drilling companies to reuse fracturing flowback fluids to reduce the quantity of fresh water pollution that results from the drilling process.

• Create incentives for drilling companies to use other non-potable water for fracturing operations, such as discharge from water treatment facilities and briny water.

• Ban the use of surface evaporation pits.

• Require gas companies to use steel tanks to store flowback fluids.

• Define fracking flowback fluids as hazardous waste rather than industrial waste.

• Release fracking fluid formulas to, at a minimum, property owners and tenants with land adjacent to or including a well site, and emergency personnel.

• The DEC should require stormwater permits for the laying of gathering lines as presumptively having a significant impact on the soil and hydrology of the Marcellus Shale region requiring the use of best management practices to control sediment erosion.

• The DEC should also provide guidance in the laying of gathering lines to ensure the protection of wetlands, stream corridors and other hydrologically sensitive areas.
Pipelines

Background

Different Federal and State agencies are involved with pipeline regulation depending primarily on what type of pipeline it is and where it is located. The following questions can help guide the reader in properly categorizing the pipeline. Once one or more agencies are identified the reader will know which regulations apply.

Types of Pipelines

Gathering lines transport gas to a processing facility. Gathering lines are regulated by the Department of Public Service. Gathering lines that cross environmentally sensitive areas are subject to DEC jurisdiction.

Transmission lines transport gas to a distribution center. Intrastate lines are regulated by the Department of Public Service. Interstate lines are regulated by the Department of Transportation and the Federal Energy Regulatory Commission.

Q: How are pipelines categorized?
A: Size:
Length and diameter are used in many of the regulations to demarcate which authority has jurisdiction over the pipeline. Length is measured in feet or miles while diameter refers to a cross-section of the pipe and is in inches.

Pressure:
Pressure is measured in pounds per square inch (PSI) of pressure that the pipe will be operating at. One hundred and twenty five PSI is a common cut-off in distinguishing between smaller pipelines (known as gathering lines or service lines) and larger lines (known as transmission lines).

Purpose
The intended or actual use of the pipeline can also determine what agency is responsible for overseeing compliance with applicable regulations. For example, some pipes are used for service, others for collection or bulk sale, and others for intra- or inter-state transmission.

Location
Location of the pipelines also governs who regulates and can help the reader find answers relating to, inter alia, siting, eminent domain, and the permit and construction process. The reader should take note whether the land fits within one or more of the following categories of land:
- Federal,
- State,
- Private unleased, or
- Private leased.

Once pipelines are categorized using the above criteria the reader will be able to navigate the regulations and search out answers to specific questions about the pipeline at issue.
Ground Coverage, Location and Spacing

Q: Who regulates permitting and siting for new interstate gas transmission pipelines?
A: The Federal Energy Regulatory Commission (FERC) is responsible for permitting and siting interstate gas transmission lines. The authorizing statute for this authority is the Natural Gas Act of 1938 which grants FERC authority to review interstate pipeline proposals. FERC can coordinate placement with state and local groups and can control transmission line routes.

Q: What state authority primarily regulates pipelines?
A: The New York Public Service Commission (PSC) (http://www.dps.state.ny.us/)

Q: What pipelines does the Department of Public Service (DPS) regulate?
A: Gathering lines — 16 NYCRR 255.9
Service lines — 16 NYCRR 255.361
Transmission Lines — 16 NYCRR 255.301 et seq.

Q: What are the different ways land is acquired for pipeline routes?
A: • Easement (contractual)
  • Right-of-way
  • Taking
  • Condemnation

Q: Is there a difference between a right-of-way and an easement?
A: A right-of-way occurs where a gas company acquires title to property for the purpose of installing a pipeline. Easements are more common and occur where a gas company secures a right of occupancy without acquiring the property itself.

Q: How deep must pipes be buried?
A: Depth is measured from the top of the buried pipe to the surface. Pipes must be buried at least two feet deep, except where solid rock is encountered, in which case the pipeline must be buried at least one foot. Additional coverage of the pipeline should be provided if there is a risk of erosion or where future grading is likely, such as at a road, highway, railroad or ditch crossing. Where land has been cultivated for commercial farm purposes at least two of the past five years, pipes shall be installed with a minimum of 40 inches of cover unless the farmer agrees that normal agricultural practices, such as plowing or disking, can be safely accommodated with a cover of less than 40 inches.

Q: How is pipeline location determined and what factors guide this decision?
A: Environmental sensitivity of the area, availability of land, and need for the pipeline to take a certain route are common factors that influence the siting of pipelines. The showing that must be made by an entity seeking approval for a new pipeline varies depending on the regulatory agency. The regulations should be consulted directly.

Q: To what extent do pipes have to be placed in the same easement/trench line?
A: Most of the regulations require that the pipelines be placed, when feasible, in existing trench lines and that new pipes be consolidated whenever possible.
Q: How are rights-of-way granted across federal lands?
A: Rights-of-way through federal public lands, including the United States forest reserves, may be granted “by the Secretary of the Interior to qualified persons for a pipeline to transport oil or natural gas, or for a pumping station. Permission may be granted for the ground occupied by the pipeline and 25 feet on each side.” http://web2.westlaw.com/result/do

Q: What showing must FERC make for a new right-of-way to be granted for gas pipelines?
A: The Federal Energy Regulatory Commission’s finding of a need for a proposed natural gas pipeline project must be supported by substantial evidence, as required by § 19(b) of the Natural Gas Act (15 U.S.C.A. § 717r(b)). http://web2.westlaw.com/result/

Q: What is the size of the easement granted for use of the pipes?
A: Easement sizes vary from a very small width to many meters across. The width is generally governed by the size of the pipe to be buried and the need to access the easement for excavating or for future maintenance. Safety is also a concern: higher capacity pipes are generally set off further from buildings and uncleared land. The width of the easement is determined during the permit application process for the proposed pipeline. If, however, the land is privately leased land, the easement is implied and is subject to the terms of the lease agreement.

Q: What environmental protections are required?
A: Environmental criteria for siting a pipeline are fairly encompassing. Regulations for many of the transmission lines require extensive environmental mitigation measures to be taken in order for a pipeline permit to be issued.

Q: How difficult is it to obtain a permit for this category of pipeline?
A: In general, the larger the pipeline and the more correlated its intended use to large scale conveyance of gas, the more arduous the permitting process will be. The regulations also provide for varying degrees of public notice and opportunity to comment on the proposed pipeline.

Q: Who controls the use of right-of-ways?
A: The agency to which the pipeline applicant submitted its proposal controls the use of the right-of-way. Any proposed use of the right of way must be cleared with that agency. Other entities such as municipalities are preempted from allowing any other use inconsistent with the agency’s regulations.

Pollutants and Storm Water Discharges

Q: Who regulates pollutant discharge from pipelines?
A: Under the Clean Water Act (CWA), national pollutant discharge elimination system (NPDES) permits can be required for “discharge of process or test water during construction and operation of pipeline facilities.” Administration of this program, the Section 404 permit program, can be transferred to the states by the EPA administrator. 33 C.F.R. § 323.5. In New York, the EPA has transferred authority to the New York DEC. It should be noted, however, that the Energy Policy Act (see next question) affected the level of pipeline pollutant discharge regulation.

Q: Did the Energy Policy Act of 2005 exempt storm water discharges resulting from the
construction of natural gas pipelines from the NPDES permit requirements?
A: Yes, in part. The DEC can still require NPDES permits “when the discharge of a pollutant other than sediment contributes to a violation of an applicable water quality standard.” See 40 C.F.R. § 122.26(a)(2)(ii). As a general rule, however, the EPA exempts natural gas pipeline construction from NPDES permit requirements. (http://www.steny.org/usr/)

Safety and Maintenance

Q: Who regulates the safety of interstate gas transmission lines?
A: The National Gas Pipeline Safety Act governs safety requirements for interstate gas transmission lines and expressly preempts more stringent regulation of such lines by state agencies. See 49 U.S.C. App. § 1672(a)(1). The Department of Transportation’s Pipeline and Hazardous Material Safety Administration (PHMSA), through its Office of Pipeline Safety (OPS), administers national regulations to assure safe transportation of natural gas, petroleum, and other hazardous materials by pipeline.

Q: Who is responsible for making sure that pipelines maintain their integrity as they age?
A: The United States Department of Transportation (DOT). Under the Pipeline Safety Improvement Act of 2002, pipeline operators must prepare and implement an “integrity management program” (IMP). The IMP requires that high risk areas be identified (referred to as “High Consequence Areas”) and that risk analysis be done on these areas. Additionally, the entire pipeline system must be given periodic integrity assessments. The pipelines must be re-inspected every seven years.

Q: The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPESA) made revisions to IMP’s under the Pipeline Safety Improvement Act of 2002; what did it add?
A: The 2006 Act Added the following:
1. Minimum standards for IMPs for distribution pipelines (including installation of excess flow valves on single family residential service lines on the basis of feasibility and risk);
2. Standards for managing gas and hazardous liquid pipelines to reduce risks associated with human factors (e.g., fatigue);
3. Authority for the Secretary to waive safety standards in emergencies;
4. Authority for the Secretary to assist in restoration of disrupted pipeline operations;
5. Updated incident reporting requirements;
6. Requirements for senior executive officers to certify operator integrity management performance reports;
7. Clarification of jurisdiction between states and Pipeline and Hazardous Material Safety Administration (PHMSA), a division of the DOT, for short laterals that feed industrial and electric generator consumers from interstate natural gas pipelines.”

Q: What about the danger that buried pipelines will be hit and ruptured during excavation?
A: This is one of the concerns that the 2006 Act (PIPESA) sought to address. Excavators are required to call before they dig so that pipeline operators can locate the buried pipelines. The DOT may enforce penalties against a variety of entities under the 2006 Act, including penalties against:
- **Excavators**: if excavators do not report damage to pipes or gas released during excavation or if they disregard buried pipeline markers, the DOT may impose penalties.
- **Pipeline Operators**: if pipeline operators fail to respond to a locating request or do not accurately
mark the location of the buried pipes, the DOT may impose penalties.

Q: Does the sGEIS address gathering lines, transmission lines, or ancillary facilities such as compression stations?
A: No. The PSC, not the Department of Environmental Conservation, regulates gathering lines, transmission lines, and compression stations.

Q: Can a landowner build over buried pipelines?
A: Generally not. Buildings should not be constructed over pipelines for obvious reasons, but other uses of the land may be possible such as farming or placement of a road. As such, owners should make sure that their leases specify the location(s) of possible future construction. If the land is taken by eminent domain or condemnation then above-ground use is more limited. Land use above the pipelines is site specific so the regulations should be consulted directly.

Technical Department of Public Service Regulatory Questions

Q: What is the Department of Public Service?
A: The Department is mandated under state law to ensure access to reliable and low-cost utility services. The Department constitutes staff of the Public Service Commission. The Commission regulates the state's gas, electric, water, and other utilities. Under state law, the Commission has the responsibility for setting rates and ensuring adequate service is provided by New York's utilities. In particular, the Commission exercises jurisdiction over the siting of gas pipelines and has responsibility for ensuring their safety.

Q: What are the DPS regulations for pipelines extending more than 1000 ft but less than ten miles with a PSI of 125 or more?
A: The application for construction of these pipelines must include:
   • two copies of the Environmental Management and Construction Standards and Practice, setting forth the protocols that must be followed “to protect and minimize the impact to the environment during installation and maintenance of all such lines,” and
   • two certified statements agreeing to install and maintain the lines as directed by the DPS. 16 NYCRR 85-1.1;

Q: What additional rules apply to pipelines greater than six inches in diameter?
A: The Notice of Intent must include:
   • the intended date for construction to begin;
   • a map and description of the path the line will take, including the length of the pipe, the depth it will be buried, the maximum allowable operating pressure, right of way width, width of any area to be cleared, any known underground facilities to be crossed or paralleled, wells connecting to the line, the point where the line connects with another line, existing and proposed access roads, location of compressor stations (detailed description), and the name of every municipality the line will cross;
   • the zoning and environmental conditions of the lands the pipeline will cross need to be thoroughly detailed, including scenic areas, historic landmarks and other visual resources. 16 NYCRR 85-1.2
Q: What rules apply to all other pipeline diameters and lengths under 10 miles?
A: The Notice of Intent must include everything listed above, plus:
   • property boundaries;
   • any dwelling within 150 feet;
   • a statement explaining the need for the line, including a demonstration that a market or specific purchaser for the gas will exist.
   • any other information the applicant considers relevant. 16 NYCRR 85-1.3

Q: What are the DPS regulations for pipelines extending more than 10 miles with a PSI of 125 or more?
A: The application must include:
   • description of the proposed facility;
   • statement of the location of the proposed site or right-of-way;
   • summary and description of any studies which have been made of the environmental impact of the proposed project;
   • statement explaining the need for the proposed facility;
   • description of any reasonable alternate locations or routes for the proposed facility, including a description of the comparative merits and detriments of each location or route and a statement explaining why the primary location or route is best suited for the proposed facility; and
   • other information the applicant deems necessary or desirable. 16 NYCRR 85-2.1 et seq.; see also http://www.dps.state.ny.us/articlevii_Gas_Elect.pdf.

Q: What action will the DPS take if it determines that more information is required before a permitting decision can be made?
A: The commissioner or the presiding officer may request additional studies or materials that the applicant must then provide.16 NYCRR 85-2.5.

The exhibits that must be attached to a permit application are a great way to see what considerations the permit requesting entity must take into account during its decision making process. Once the exhibits are filed they are available publicly and should be consulted to see if comment or intervention is needed in order to address other concerns.

Q: What are the advantages of the permitting requirements?
A: Once the exhibits are filed they are available publicly and should be consulted to see if comment or intervention is needed in order to address other concerns. The exhibits that must be attached to a permit application are a good way to see what considerations the permit requesting entity must take into account during its decision making process.

Q: What should be included in the exhibits?
A: The applicant should show the location of facilities and an environmental impact statement.
Public Participation for Siting and Construction

Q: Who may file comments on the proposed pipeline?
A: Once an NOI is filed, any person may file comments on it. 16 NYCRR 85-1.7

Interested groups or persons are invited and encouraged to consult with the staff of the commission on any part of the proposed line. 16 NYCRR 85-2.6

Other groups may intervene in the DPS proceeding if they meet the following definition:

*Any domestic non-profit organization or group formed: to promote conservation or natural beauty, to promote the environment, personal health or other biological values; to preserve historic sites; to promote consumer interests; to represent the interests of commercial or industrial groups; to promote the orderly development of the areas in which the facility is proposed to be located.*

These groups may participate in a certification proceeding if they file a notice within 30 days after the date given in the public notice as the date for filing of the application. Other groups not fitting the above definition can intervene if they can show that they would provide beneficial insight or promote the public interest. 16 NYCRR 85-2.11

Q: Who may intervene as a matter of right in a proceeding to grant a DPS permit?
A: 16 NYCRR 8502.11(a) outlines who can participate in a certification proceeding for a DPS permit, as long as they have made a timely application for participation:

- state agencies, such as the DEC, the Department of Agriculture and Markets, and the Office of Parks, Recreation and Historic Preservation
- any municipality entitled to receive notice under 16 NYCRR 85-2.10(a)(1)
- any individual resident in a municipality entitled to receive notice under 16 NYCRR 85-2.10(a)(1)
- any domestic nonprofit corporation or association, formed at least in part to:
  - promote conservation or natural beauty
  - protect the environment, personal health or other biological values
  - preserve historic sites
  - promote consumer interests
  - represent the interests of commercial and industrial groups, or
  - promote the orderly development of the areas in which the facility is proposed to be located

This section is quite inclusive and allows for broad participation on a local basis by municipalities and public interest organizations.

In addition to the groups listed above, 16 NYCRR 85-2.11(c) allows other persons or organizations not listed in 16 NYCRR 85-2.11(a) to request permission to intervene in a DPS certification proceeding. These persons or organizations must include the following items in a request for permission:

- the information specified in paragraph (1) of this subdivision, and
- an explanation of how their intervention would be “likely to contribute to the development of a complete record or why it would otherwise be fair and in the public interest.”

Requests for non-listed persons and organizations is governed by 16 NYCRR 4.3.
Appendix A: Gas Leases

Q: What is a General Gas Leasing Clause?
A: A lease is a legally binding contract that grants both rights and obligations to the parties who sign it. Entering into a gas lease agreement does not necessarily mean that a well will be drilled on your property. However, the gas lease gives the gas company (lessee) working interest in the owner’s land (lessor) with rights to drill, explore, produce, measure and market production of gas.

Q: Can I adjust the terms in my lease?
A: Gas leases take the form of a standard lease where gas companies offer a pre-made lease document. Although these leases seem non-negotiable due to their prior drafting, they are actually partly negotiable. Landowners should keep in mind that they still have some bargaining power and thus should consider adding various provisions and addenda safeguarding their interests.

Q: What are some landowner provisions that can be added into leases?
A:
• Requirement for groundwater testing at various times throughout the process preferably by an independent testing entity;
• Wastewater disposal procedures;
• Emergency response plan;
• Drilling technique descriptions;
• Access road specifications, such as location, size, and number;
• Distance minimums between wells and existing buildings on the property or areas of the property where development is anticipated.

Q: How is a lease described in terms of areas it covers?
A: The lease will usually specify property by tax map number and the surrounding lands. But some leases extend to contiguous, adjacent lands you may own, thus expanding the lease to include larger areas.

Q: What is a lease term?
A: All leases specify duration for a primary term, which is usually for five years. Some leases extend after the primary term is over into a secondary term that lasts as long as production is active or as mentioned in the lease. Landowners should therefore be wary of wording such as “so long thereafter as required by Lessee” or “so long thereafter as operations are continued” since this can affect the lease term.

• Caution: newer leases tend to have extension of surface rights past lease expiration.

Q: Does the gas company have the option to extend the primary term?
A: Some leases have a clause in their writings granting the gas company the right to extend the lease for an additional term subject to the same conditions under the primary term.

Q: What can landowners do about this?
A: Landowners should opt for a right of first refusal instead of an automatic
renewal option once the primary term ends. A right of first refusal will give landowners a better bargain, since this option gives gas companies the right to match competitor’s offers for lease renewal.

Q: How and what payments are made to landowners?  
A: There are three types of payments offered:

1. **Land rental fees** (3 variations)
   i.  *Paid-Up lease:* this type of payment option allows for one payment for annual lease rental amounts paid concurrently with the bonus
   
   ii.  *Annual Payments*
   
   iii.  *Delay Rentals:* Traditionally, the gas company would drill immediately once a lease was signed. Today, immediate drilling is unrealistic due to preparatory needs, creating the option of delay rentals. Delay rentals are payments made upfront to the lessor in order to delay drilling.

   Q: Can delay rentals extend the primary term?  
   A: Old cases say no, but newer ones tend to be more favorable towards the gas industry. In addition there is further ambiguity as to how courts will rule due to the ambiguous state of the law in New York on this topic since there is no case on point.

2. **Bonuses:** these are one time payments that landowners receive upon signing a lease

3. **Royalty Payments:** these are payments giving landowners a portion of the gas value when gas is removed from their property

   Q: Can you get royalties if the gas company is not extracting gas from you?  
   A: NO.

   Q: How are royalties calculated under natural gas leases in New York?  
   A: They are calculated according to the terms of the lease. In general, the amount owed to the landowner will be a given percentage (usually expressed as a fraction, e.g. 1/8th) of the profits from the gas sales. Profits are also determined according to the lease terms but can be generally understood as gross sales of the extracted gas minus the operating costs and expenses.

   Q: Is there a standard royalty percentage for natural gas leases in New York?  
   A: Since market forces control the royalty rates, there is no set standard royalty percentage. However, integration hearings before the Division of Mineral Resources show that “all thirteen companies which have drilled wells subject to integration in New York have leased for a 1/8th (12.5%) royalty.” See Gas Lease questions on the DEC website at http://www.dec.ny.gov/

   Q: Will I only receive a royalty from commencement of production if I lease to the well operator who drills the well? If I don’t lease, or lease to someone else, will my royalty be delayed?  
   A: “If your acreage is within a spacing unit and you do not lease then your
rights will be addressed by the compulsory integration process (see “Compulsory Integration” section below). If gas is sold from the well in the unit and you elect to be an “Integrated Royalty Owner” you will receive a royalty for production. The well operator must pay “Integrated Royalty Owners” promptly and no less frequently than it pays its lessors. If the integration order is issued before the first product sales, royalties will be paid when production begins. If you lease to another company (other than the operator) who participates in the well, then you will be paid by your lessee from the beginning of production if that is what your lease requires.” See Gas Lease questions on the DEC website at http://www.dec.ny.gov/ 

Q: How do I get the best price in a lease?  
A: Price bargaining. Landowners should consider negotiating a lease as a group with other landowners in order to increase their bargaining power with respect to the gas companies. This will also be appealing to gas companies since they in turn will be able to save costs by obtaining larger tracts of land by negotiating one contract instead of many smaller ones. Landowners should keep their options open:

- Negotiation with more than one gas operator can increase the value you receive for your land. It could lead to competitive bidding and as companies bid against each other higher prices and more favorable terms can result.
- Negotiate the terms that will protect your interest. Communicate your goals to an attorney and have them negotiate the terms for you. That way you can be sure that your interests are protected from a legal standpoint.

Q: What other concerns should I take into consideration?  
A:

Q: Will failure to make payments cancel the lease?  
A: Only if it is so stated in the lease.

Q: Will lessors be taxed for their gas earnings?  
A: Landowners may want to find out if they can add a free natural gas provision so that they can receive an amount for the gas at no cost.

Q: Does a royalty apply only to the portion of the land that is producing the gas even if the rest of the leased land is not?  
A: It is ambiguous as to how courts will deal with this situation, therefore, landowners should have a lawyer draft a Pugh clause on their lease contract. This clause describes what happens to the portion of the leased land that either does not have a well or is not included in a producing gas unit. There are two types of Pugh clauses:

- **Horizontal Pugh Clause:** at the end of the primary term, this clause releases land that is not found within a producing unit
- **Vertical Pugh Clause:** this establishes a depth limit by which lands past a certain depth will be released at the end of the primary term

See [http://www.romingerlegal.com/fifthcircuit/opinions/91-4318.0.wpd.html](http://www.romingerlegal.com/fifthcircuit/opinions/91-4318.0.wpd.html)

Q: What surface rights are given to the gas company?  
A: Standard leases grant very broad rights, so lessors may want to add certain municipal regulation limitations such as control of well location, excessive noise, water removal, aquifers,
and access to roads. Additionally, landowners may want to add a provision on their lease providing them for remedy in the case of damage to livestock, crops, building, etc.

**Q:** Should I only grant subsurface rights?
**A:** For very small surface areas you may seek to only grant subsurface rights.

**Q:** Are landowners safe from giving surface rights away to gas companies?
**A:** Not necessarily. The gas company may want to engage in unitization amongst groups of neighbors in order to obtain large areas of land. Unitization allows landowners to receive payments based on their pro-rated share of their land even if it is their neighbor’s land which is being drilled.

**Q:** Does a lease give the well operator the right to “trespass” on my land?
**A:** Under a lease agreement the lessee does have an implied easement to use the surface of the land as may be reasonably necessary to obtain production. This will be true unless the lease has specific provisions against surface entry. This type of lease is known as a “non-surface entry lease.” If concerns exist about specific surface disturbances lessors should negotiate appropriate protective measures into the lease agreement. For example, express lease provisions could address the location of access roads, the proximity of pipelines or wells to structures on the property or sites of future buildings, and can place responsibility for surface damages on the lessee. See Gas Lease questions on the DEC website at http://www.dec.ny.gov/

**Q:** If I sign a lease, am I transferring possession of my property, allowing the gas company to tear down my house to drill a well?
**A:** NO. An oil and gas lease will place obligations on the lessee and lessor which should be fully understood before signing the lease, but these provisions do not allow the lessee to destroy existing buildings. It should be noted, however, that a lease is different from a purchase agreement or mineral deed, which do involve the transfer of property.

**Q:** What rights to gas companies have regarding gas storage?
**A:** Leases have a provision on gas storage which grants the gas company the right to convert the leasehold or lands pooled/unitized therewith to gas storage as long as delay rentals are paid. This provision is convenient when the land has a well that is “shut-in” and not producing marketable gas or is completely depleted. However, some companies use the storage of gas idea to continue to extend the lease. It is important to note that no royalties will be paid for gas storage.

**Q:** Do standard oil and gas leases allow the operator to store gas in tanks on my property?
**A:** NO. “Oil and water may be stored in tanks on site but producing wells convey gas off the property through gathering lines. These underground gathering lines bring the gas to a sales meter and then to an end-user or major gas transmission line. If the well is on-line, gas flows through the gathering system. If the well is shut-in, gas remains in the wellbore and in the underground rock formations. Some proposed leases contain terms that allow the lessee to store the gas underground but, like other lease provisions, this is negotiable.” See Gas Lease questions on the DEC website at http://www.dec.ny.gov/

**Q:** What is an “entire contract” provision?
**A:** This provision states that the lease document is the entire agreement and anything
important to the landowner had to be put in writing if it is to be enforced. Anything left out of the writing is assumed to be unimportant and does not play a role in the contract. More clearly, this provision establishes that the contract cannot be changed or modified.

**Q: What can I do about this?**

**A:** Not much. Although it is clear that landowners have weak bargaining power, they will only be able to challenge contracts with such provisions on the grounds of fraud and this is very difficult to prove.

**Q: What is a “force majeure” provision?**

**A:** This provision deals with a lease obligation that is prevented from fulfillment due to an act of God. Force majeure is for the benefit of the party to keep the lease in place even though drilling is affected, thus favoring the gas lease.

**Q: Can force majeure be used to extend leases?**

**A:** NO.

**Q: What if I want to cancel a lease?**

**A:** Following certain procedural requirements, you have the right to cancel for three business days after signing the lease. However, right of rescission is ineffective since the company rarely signs the lease. Most printed leases contain automatic renewal provisions at the option of the gas company. Recently, gas companies have been invoking force majeure clauses to argue that a lease has not expired.

**Q: What are the consequences if I do not cancel after three days?**

**A:** Canceling after three days can give the business the right to pursue damages against you in court. The amount of money you may have to pay can be substantial. Consult an attorney so that you fully understand your liability before doing so.

**Note on Compulsory Integration:** if you have signed a lease, then the compulsory integration process does not apply to you. Please see “Gas Lease Questions” section above for lease related questions.

1. The first set of questions address the regulatory process of how spacing units are assigned, the permit process, and a general timetable of action.
2. The second set of questions clarify who is subject to spacing units and differentiates between leased lands and those who are made parties to the spacing unit through the compulsory integration process.
3. The third set of questions goes to the options available to unleased portions of land within a spacing unit. (Note: leased lands are not subject to compulsory integration).

**Q: Is the lease cancelled if royalties are not paid?**

**A:** NO. You need to give the gas company notice and they have 60 days to try to meet your concerns. Once the 60 days elapse, then you can bring a court action.

**Q: Will defective acknowledgments void a lease?**

**A:** Probably not. Acknowledgments are solely a requirement for recording and bear no effect on parties’ agreements. They are mainly important for third parties who may want to purchase this land.

**Q: Can gas companies take gas from under your land if you do not sign a lease?**

**A:** YES. If your land is within a spacing unit, you are compulsorily integrated, whether you want to be or not and you are compensated for the gas as an integrated royalty owner.
Compulsory Integration is actually for the benefit of the lessor. Traditionally, a drilling race ensued when there was a reservoir under various properties. In an effort to obtain orderly exploitation of natural resource, the compulsory integration provision was added.

**Q: What rights to gas companies have with respect to pipelines?**

A: Most leases provide for the right for gathering lines and for pipelines to come through from adjoining lines. The public service commission only regulates gas-lines over a certain amount and thus you need to be wary of leases granting too much access through pipeline use.

**Q: Should I add an indemnification clause to my lease?**

A: Yes. In the event of any liability this provision creates a duty on the gas company to protect or compensate you for loss and injury.

**Q: Interpreting Leases: Do the same terms mean the same thing in every lease?**

A: Terms relating to payments under the lease, length of the lease as well as others can be calculated in different ways. For example, two leases that both provide for royalty payments of 1/8 may nonetheless be calculated in very different ways. Make sure you understand how the terms of your lease are calculated. Ask questions and be sure to consult an attorney to make sure what is written down reflects your understanding.

**Q: What things should I consider before signing a lease?**

A:

- **Land disturbance from an access road and drill site:** the actual drilling of a well is a temporary activity that may involve large amounts of equipment similar to other construction projects. Be sure that you know how much of your land and which parts of it will be used for access, drilling, production, pipelines, compressors, and short or long term storage of equipment. Additionally, have mutually approved reclamation plans incorporated into your lease.

- **Damage to crops, buildings, and other personal property:** the lease can also be written to require fences or other safeguards if needed to protect people or livestock. If not covered in the lease, consider asking for terms that make the company responsible for damage to crops, livestock, buildings, and other personal property.

- **Free gas:** leases may provide for free natural gas for the landowner’s use if a well is drilled on the premises. If the lease does not specify that the company is responsible for the cost of equipment and installation, then you may have to pay for it. Because of safety concerns, the company may provide for monetary payment in lieu of free gas as an alternative.

- **Lease assignment:** the lease may contain a clause which allows the company to assign or sell the lease to other firms.

- **Underground gas storage:** gas production reservoirs are ideally suited for underground gas storage after the gas has been produced. The lease may contain a clause which permits gas storage in return for an annual rental payment.
- **Note:** the above discussion was excerpted from the DEC website at http://www.dec.ny.gov/. While paraphrased slightly the direct quotations from the source are omitted for readability purposes.

Q: **What if there is a dispute with a drilling company?**
A: Most “standard leases” contain a provision that requires the use of arbitration to resolve disputes between the landowner and the gas company. Arbitration panels typically consist of three arbitrators. The lessor and the lessee each pay the fee for one arbiter and split the fee of the third. Arbitrations can be very expensive. In some cases you may be required to pay the company’s fees if the arbitrators decide against you.

Q: **What if I want to sell my land?**
A: Entering into a gas lease means that you are granting a right to others which is viewed as an encumbrance on property title. Thus, entering into a gas lease could have ramifications in connection with a possible sale or mortgaging of the property.

Q: **To what extent are leased lands subject to regulation?**
A: “Private leases are not subject to DEC’s jurisdiction, nor are local governmental intervention typically involved.”

Because of the apparent absence of regulation in leased lands the mitigation measures relating to environmental harms are generally left up to contract agreement. To this end, provisions that can be incorporated into leases become important for two reasons.

1. Since lease provisions seem to be the only means of ensuring environmental protection, they need to be properly written.
2. Landowners may be able to increase their bargaining position with respect to the gas companies by adding provisions to their lease. Leverage directly relates to the amount of protective provisions that can be placed in leases through negotiations with the gas company. Additionally, the measures that landowners can take to increase their position can also insure greater uniformity from one piece of leased land to the next because of collective bargaining.

Q: **Is it better to seek compensation through the compulsory integration or forced pooling process rather than by an oil and gas lease?**
A: Only individual assessment of the pros and cons of each option on a case by case basis can be made. Landowners should consult their attorney.

Q: **If I have an oil and gas lease, is all of my acreage part of the spacing unit and is production allocated to all of my acreage?**
A: “Until the Department issues a well permit, there is no certainty about where a well will be or what the spacing unit will look like. If the well permit has been issued or an application for one has been received, then the spacing unit map is available for review by contacting the appropriate Division of Mineral Resources regional minerals manager for oil and gas.” See Gas Lease questions on the DEC website at http://www.dec.ny.gov/

**Compulsory Integration**

Q: **What are “pooling” and “compulsory integration”?**
A: “If your acreage is in the spacing unit and you don’t lease, then your rights will be addressed by the compulsory integration process. If gas is sold from the well in the unit and you elect to be integrated as an “Integrated Royalty Owner,” then you will receive a royalty for production. The well operator must pay Integrated Royalty Owners promptly and no less frequently than it pays its lessors. Assuming the integration order is issued prior to first product sales, royalties will be paid upon commencement of production. If you lease to another company (other than the operator) who participates in the well, then you would be paid by your lessee from the commencement of production if that is what your lease requires.”

See Gas Lease questions on the DEC website at http://www.dec.ny.gov/

Q: When will land be subject to compulsory integration? Should a landowner sign a lease or wait?

A: Land will be subject to compulsory integration whenever the land is included in a proposed spacing unit. There is no compulsory integration process unless the DEC issues a permit to drill and the land is included in a spacing unit. Historically, “only 10-15% of the acreage leased by oil and gas companies is ever included in spacing units, and the Department cannot issue a permit to drill unless the applicant controls 60% of the acreage in a spacing unit. If everyone in a prospective area waits for compulsory integration, it will never happen because no well will be drilled.” See Gas Lease questions on the DEC website at http://www.dec.ny.gov/

Only you can determine for yourself, with appropriate legal advice, how the compensation offered for a lease on your acreage stacks up against any perceived disadvantages.

Q: Can you give a brief overview of the spacing unit and compulsory integration process?

A: As of August 2, 2005, an applicant for a permit to drill an oil or gas well in New York State must include, in the permit application, a map showing the area that will be assigned to the well. This area, called a spacing unit, may include some or all of your acreage even if you haven’t signed an oil and gas lease. After the Department of Environmental Conservation (DEC) issues a well permit, you will be required to elect an option for how your unleased acreage in the spacing unit will be integrated with other properties in the unit. Your election will be finalized by issuance of a compulsory integration order after a public hearing. This process consolidates control and management of well operations with the well operator who holds the permit from DEC. If you have leased your oil and gas rights to someone else, then you are not required to make an election; your lessee will make the decision if necessary.

Each option presents different risks and potential rewards. The option you select may subject you to certain costs and obligations, and there is no guarantee that a well will make money. You should carefully consider all the implications of your decision. If no permit is issued, then your acreage will not be affected.

The above discussion was excerpted from the DEC website at http://www.dec.ny.gov/. While paraphrased slightly the direct quotations from the source are omitted for readability purposes.
Q: What should a landowner expect to happen before a hearing if the DEC issues a well permit based on a spacing unit that includes the landowners unleased tract?
A: The following procedure is an outline excerpted from the DEC website:
1. The DEC will assign a hearing date when the permit is issued.
2. At least 30 days before the hearing, the well operator will send a notice directly to you. It will include the following:
   - Date, time and place of hearing
   - Proportion of your acreage to total acreage in spacing unit
   - Estimated well costs, including plugging costs
   - Election form for choosing your integration option
   - Draft integration order
3. You will have 21 days after receiving the form to make your election.
4. If you elect to be an “Integrated Participating Owner,” payment for your share of the estimated well costs is due to the well operator by the hearing date.

After you receive the hearing notice and before the integration hearing, you still may enter into a lease or other private agreement regarding development of your oil and gas rights. If you establish an agreement with someone other than the well operator, you should provide the notice package to that person or company immediately.

Compulsory integration hearings are held in Albany, New York, on a regular schedule. See http://www.dec.ny.gov/

Q: Are there any options besides the compulsory integration process or signing an individual lease?
A: There is no option here between one or the other. If you do not sign a lease, you automatically become an integrated royalty owner. Joint Operating Agreements are “common in the oil and gas industry.” The DEC cannot require them but does “strongly encourages these agreements between the well operator and other potential working interests within the spacing unit.” The advantage of these agreements is that business decisions such as “data sharing, payment schedules and audits” are controlled by contract instead of state government.

Q: What are the different compulsory integration options?
A: If your acreage remains unleased but it is in a spacing unit, you must choose one of the following:
   – Integration as a royalty owner
   – Integration as a non-participating owner
   – Integration as a participating owner

In what way do they differ?
• Costs
• Liabilities
• Rights to payment
• Temporally, when payments and costs are owed or due.
Q: When will the compulsory integration option choice be made?
A: In most cases, you will be making this choice before the well is drilled and “before you know whether the well will be a success that pays for itself, a marginal producer that never pays for itself, or a dry hole. Even if a well initially produces hydrocarbons, it is impossible to know in advance whether it will continue to produce for many years or for a very short time, such as a month or less. It is certain that the amount of oil or gas a well produces will decrease over time. The rate of decrease is another factor that cannot be predicted.”
See http://www.dec.ny.gov/

Q: What is a production unit?
A: It is a collection of land that is believed to contribute gas to a well from underground reservoirs. Although these areas range in size they are typically around 640 acres.
http://www.steny.org/usr/observations%20on%20gas%20production%20on%20marcelus%20shale(REV).pdf

Q: How are royalties divided among owners of a production unit?
A: The amount paid to “eligible property owners” is based on their “ownership share of the production unit.”
http://www.steny.org/usr/observations%20on%20gas%20production%20on%20marcelus%20shale(REV).pdf

Q: What can landowners do to increase their return from the well?
A: They can form groups and negotiate collectively:
The Binghamton Press reports that one collective bargaining group leased mineral rights in over 10,000 acres to a gas company. The company is reportedly paying over $110 Million to approximately 500 landowners.
See Binghamton Press and Sun Bulletin, August 3, 2008

Q: If I do not lease to the well operator, will I not receive any compensation because my acreage will be excluded from the unit?
A: No. A landowner within a spacing unit must choose one of the compulsory integration options and cannot elect to abstain from the drilling process.

Q: What does it mean to elect integration as a Royalty Owner?
  Process/Costs/Benefits/Liabilities
A: Costs - If you elect this option, you are not liable for any charges or fees associated with well operation. A dry hole costs you nothing. This is the default option if you do not make a selection.

  Compensation - If the well produces, the well operator will begin paying you a royalty shortly after production starts. The royalty will be no less than one-eighth of the revenue received by the well operator for the share of production attributable to your acreage. An integration order is not a “forced lease” and will not award you a signing bonus.

Q: What does it mean to elect integration as a Non-Participating Owner?
  Process/Costs/Benefits/Liabilities
A: Costs - If you elect this option, you will have the same responsibilities as a Participating Owner, but you do not risk your own money by paying your share of costs up front. A dry hole costs you nothing.

Compensation - You will not receive any compensation from the well operator, not even a royalty, until the well operator has, through the sale of your share of production, recovered your share of the costs plus a “risk penalty” of 200% of your share of costs, for a total of 300%. This means that the well must pay for itself three times before you are compensated. After the well pays for itself three times, or if you buy out of the risk-penalty phase by making a payment, you will receive your share of production and be treated as a Participating Owner.

If you have leased to someone other than the well operator, then your lessee may owe you a royalty during the risk-penalty phase. This is determined by your lease, and the well operator has no obligation to you.

If your lessee elects to be integrated as a non-participating owner, then the well operator must make royalty payments to your lessee during the risk penalty phase. These payments will be on a graduated scale from 1/16 up to 1/8, based on the percentage of the lessee’s costs that have been recovered through sale of production.

After recovery of the risk-penalty, Integrated Non-Participating Owners are treated the same way and have the same obligations as Integrated Participating Owners.

Non-Participating owners may bear liability for third-party claims.

Q: What does it mean to elect integration as a Participating Owner?

Process/Costs/Benefits/Liabilities

A: Costs - If you elect this option, you must pay your share of estimated well costs by the time of the integration hearing. This money will not be refunded if the well is a dry hole or does not pay for itself.

Compensation - You will receive your full share of production. However, the well operator will have a lien on your share of production to pay any outstanding amounts that you owe.

Responsibilities of Integrated Participating and Non-Participating Owners

A decision to be integrated as a participating or non-participating owner subjects you to obligations that do not enter the picture if you elect to be integrated as a royalty owner. Some of the additional considerations are as follows:

• Actual well costs. The actual cost to drill or plug the well may exceed the estimate that was provided before the hearing. You will be held liable for your share of the additional costs.
• Completion and operating costs. If the well is successful, it will cost money to complete and operate. You will be liable for your share of these costs for the life of the well.
• Gathering line costs. If the well is a producer, the well operator will provide you with the estimated costs to install a gathering line to bring the gas to market. You will have the option of paying your share up front or having your share plus 100% withheld from your
share of production proceeds.

- *Subsequent operations.* The law defines certain operations in the spacing unit, including additional work on the existing well or drilling of another well, when you again must decide to either pay up front or be subject to a risk penalty. Subsequent operations may cost as much as or more than the original drilling.

- *Other liabilities.* As an integrated participating or non-participating owner, you are liable for your proportionate share of taxes and third-party claims related to drilling and operation of the well.

*Integrated Participating Owners* are responsible for their share of costs for the life of the well. There may be time periods where costs exceed production so that money will be due to the well operator. Drilling problems may increase costs above the original estimate, or inflation may cause plugging costs to increase above original estimates. Participating owners may bear liability for third-party claims.

*Note:* The above discussion about the Process/Costs/Benefits/Liabilities of each compulsory integration process are excerpted directly (with minor reworking for readability) from the DEC webpage on “Compulsory Integration.” Quotation marks are omitted. The material is available at http://www.dec.ny.gov/

**Q:** Does the compulsory integration process give the well operator the right to “trespass” on my land? Does the DEC integration order give them this right?

**A:** DEC’s integration order will not give the well operator the right to enter your property.

**Q:** Can extracted gas ever remain on the property?

**A:** No. However, certain leases provide for the gas company to store gas underground. Such leases will provide for this expressly and usually the landowner is compensated for this.
Appendix B: Eminent Domain

Q: How does one establish a “taking” under New York law?
A: To determine whether a mineral rights owner can be awarded just compensation for a taking of mineral property, the legitimate public interest served by environmental land use restrictions must be balanced against the equally legitimate property rights of the mineral rights owner. The New York Court of Appeals has interpreted this balance to mean that a taking has occurred “only if the property is rendered unsuitable for any reasonable income producing or private use for which it is adapted, and thus its economic value, or all but a bare residue of its value, is destroyed.”

Q: What evidence must be shown to establish a taking?
A: (1) The monetary value of the property under its current use and the value of the property under its permitted use.
(2) It must be shown that a permit was applied for and denied.
(3) It must be demonstrated that the effect of the denial is to prevent economically viable use of the land, and
(4) It must be shown that the mineral rights were acquired before the regulations that limit the property use.
The courts will hear a takings claim only if “dollars and cents” value loss can be shown and that administrative avenues for addressing the issue have been resolved. The mineral owner must also demonstrate that the prohibited use would not have a negative or conflict-creating effect on the protected land.

Q: What can a mineral rights owner do if a permit is not granted and they cannot establish a taking?
A: Regulations and/or permit conditions restricting well locations rarely eliminate all drilling options. As such, it is likely still possible to “utilize advanced drilling techniques such as directional drilling” to access the gas. It should be noted however that these techniques come at a cost and many can be cost prohibitive if a large gas reserve is not anticipated.

Q: What entities may exercise eminent domain in New York?
A: The following is a very helpful discussion on eminent domain in the State of New York. It is taken from a New York practice digest available on Westlaw (see hyperlink at the end). The original footnotes are left in place - the relevant parts of which are attached - so that the legal authority can be cited to.

The right of eminent domain is not inherent in any private corporation, but the power of eminent domain has been expressly vested by the legislature in various private corporations, including gas corporations and pipeline corporations.[FN1]

A gas corporation has power and authority to acquire real estate necessary for its corporate purpose by condemnation,[FN2] including a right-of-way for its pipeline through the property of others, once the public service department has made findings that the proposed pipeline is convenient and necessary for the public service.[FN3] Also, if it holds a certificate of public convenience and necessity, a natural gas company which is subject to the regulatory jurisdiction of the Federal Power
Commission, may, by the exercise of the power of eminent domain, acquire necessary pipeline rights of way, and in addition thereto, the land it requires for compressor stations, pressure apparatus, or other equipment incident to the operation of such a pipeline, if it cannot acquire such land by contract or is unable to agree with the owner on the amount of compensation.[FN4] The right of such a company to condemn a pipeline right-of-way has been recognized as absolute, whether the pipeline is intended for the transportation of gas across the state for sale in another state,[FN5] or to deliver gas from an out-of-state source to points within the state.[FN6]

Where a foreign corporation meeting the definition of a natural gas company complies with the provisions of the Natural Gas Act, its right to acquire by eminent domain a necessary and reasonable route across private property within the state may not be denied because the corporation has not complied with the procedural requirements prescribed by the Transportation Corporations Law.[FN7]

A corporation empowered to produce, transport, distribute, or store gas within the state for ultimate public use, and which holds an underground storage permit, or which is otherwise lawfully operating an underground storage reservoir, and which, after reasonable effort, is unable to obtain rights in real property and wells necessary for activation, operation, or protection of such reservoir, is empowered to acquire such rights by condemnation, subject to certain restrictions imposed by the statute.[FN8]

As to condemnation of a right-of-way by a pipeline corporation, see § 84.


[FN3] Home Gas Co. v. Eckerson, 197 Misc. 793, 94 N.Y.S.2d 221 (County Ct. 1950), holding that a corporation organized as a private business corporation before the enactment of the Transportation Corporations Law, for the purpose of supplying gas for public use by acquiring and selling gas at wholesale to public utilities, was a Transportation Corporations Law gas corporation and had the right to acquire rights of way by eminent domain, since it was clothed with a public interest and the laying of its pipeline was a public necessity even though it was engaged in a private business.

[FN4] 15 U.S.C.A. § 717f(h), which also has provisions permitting the institution of condemnation proceedings in federal or state courts, and requiring conformity as close as possible to state practice and procedure if the proceeding is brought in a federal court.
As to federal regulation of pipelines, see § 68.


[FN7] Tennessee Gas Transmission Co. v. Schmidt, 108 N.Y.S.2d 435 (Sup 1951), involving a gas pipeline and holding that a foreign corporation was not barred from exercising the right to take property by eminent domain because it had not been organized in accordance with the statute applicable to pipeline corporations.

As to permits for underground storage of gas or liquefied petroleum gas, see N.Y. Jur. 2d, Energy § 153.
Appendix C: Alternative Dispute Resolution

This section is still being drafted and will shortly follow

Introduction

The traditional response to conflict resolution in the legal community has been litigation. Jacqueline however, there are other problem-solving approaches available through alternative dispute resolution (ADR) that can help disputing parties achieve their goals. Id. at 1-2. “ADR is an umbrella term that refers generally to alternative to the court adjudication of disputes such as negotiation, mediation, arbitration, mini-trial and summary jury trial.” Id. at 2. These different forms of conflict resolution offer creative solutions to problem solving that may better address a particular person’s needs than litigation. Litigation is not necessarily the one size fits all solution to conflicts because it has its own drawbacks. For example, if disputing parties are in a long-term relationship then litigation may not be the right approach to resolving their problems because it is a contentious process that may exacerbate the existing tensions in the relationship and contribute to its demise. Solving the problem through mediation might be a better idea because mediation emphasizes reaching a solution to the problem through a cooperative process seeking to identify the underlying common goals and interests of the parties. In this context, mediation is likely to help repair or maintain the relationship between the parties.

Q: What is ADR?
A: ADR stands for alternative dispute resolution. ADR refers to alternative methods of conflict resolution besides litigation. Some common forms of ADR are mediation, arbitration and negotiation.

Q2: Where is the difference between mediation and arbitration?
A2:

Q3: Where can I find mediators or arbitrators?
A:

- www.adr.org
- www.Cpradr.org
- www.Adroptions.com
- Imimediation.org
- Iam.org
- www.cca.org
Appendix D: Potential Environmental & Community Impacts

INTRODUCTION

This appendix examines the environmental and community impacts associated with natural gas drilling, including the impacts that can be expected in the normal course of drilling as well as the impacts that may result unexpectedly through carelessness or error. This section draws largely on a growing body of empirical information that elucidates the details of contemporary natural gas drilling. For reference, the dSGEIS notes that “the rig work for a single horizontal well—including drilling, casing and cementing—would generally last about four to five weeks, subject to extension for slow drilling or other unexpected problems or delays.” A resident in Van Etten, New York found that drilling preparation went longer than expected, ultimately totaling three months.

EXPECTED IMPACTS

Noise of transportation and drilling

According to the dSGEIS, “moderate to significant noise impacts may be experienced within 1,000 feet of a well site during the drilling phase.” where operations continue for 24 hours a day. Noise sources, which continue for 24 hours a day, include “drilling rig operations, pipe handling, compressors, and operation of trucks, backhoes, tractors and cement mixing.” A resident in Van Etten, New York described her family’s experience this way: “24-hour-a-day drilling, ramming noise, lit up all night.” Residents in DISH, Texas have complained about the noise and vibrations of compressor stations on drilling sites, which, among other complaints, led to an ambient air quality investigation. “Considerable noise was present in all directions favorable with the wind patterns. Compressors exhibited both the operation high pitch whirl as indicated by elevated decibel readings and heavy low decibel vibration tones.” Noise pollution is a significant concern of the Allegheny Defense Project, and was highlighted in a recent

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6 dSGEIS at 7-107.
7 Id. at 7-108.
8 Mingis at 1.
10 Id.
documentary on natural gas development in Colorado. Residents featured in the film experienced 200–300 trucks traveling per day during construction of the well.

**Air pollution**

Residents in Colorado have noticed a decrease in air quality due to extensive drilling. An air quality study conducted in DISH, Texas produced the following results:

Laboratory results confirmed the presence of multiple Recognized and Suspected Human Carcinogens in fugitive air emissions present on several locations test in the Town of DISH. The compounds identified are commonly known to emanate from industrial processes directly related to the natural gas industrial processes of exploration, drilling, flaring and compression. The laboratory results confirmed levels in excess of TCEQ’s [Texas Commission on Environmental Quality's] Short Term and Long Term ESLs [Effects Screening Levels]. In addition, several locations confirmed exceedences in a chemical identified by TCEQ with the capability for ‘disaster potential.’ The Town of DISH has virtually no heavy industry other than the compression stations.

A study conducted on the emissions from oil and gas production in the Barnett Shale region also revealed evidence of significant air pollution, although the figures for natural gas are not isolated. This region in Texas supported 7,700 wells in June 2008. Sources of air pollution include “compressor engine exhausts, oil and condensate tank vents, production well fugitives, well drilling and hydraulic fracturing, well completions, natural gas processing and transmission fugitives.” The results, presented comparatively, were:

A recent emissions inventory has estimated 2009 NOx emissions from all [Dallas-Fort Worth] area airports to be approximately 14 tpd [tons per day], with VOC [volatile organic chemical] emissions at approximately 2.6 tpd, resulting in total ozone and particulate matter precursor emissions of approximately 16 tpd. For comparison, emissions of VOC + NOx in summer 2009 from just the compressor engines in the Barnett Shale area will be approximately 65 tpd, and summer condensate tanks emissions will be approximately 146 tpd.

**Road damage and traffic disruption**

13 **Id.**
14 **Id.**
15 DISH Report at 6. “The ESLs are established limits of exposures to chemicals based on their potential for adverse health effects, odor/nuisance potential and effects on vegetation.” Disaster potential is defined as chemicals with high toxicity to human life, among other things. DISH Report at 5.
17 **Id.** at 1.
18 **Id.** at 5.
19 **Id.** at 25.
The dSGEIS estimates the number of truck trips throughout the life of a well at 890–1340, with mitigation possible through multi-well pads, reused flowback water, and centralized water impoundments that may make it economically feasible to pipe water to the site.\textsuperscript{20} The United States Geological Survey (USGS) Fact Sheet expresses concern that transporting equipment, vehicles, and supplies to drill sites over rural roads could cause erosion and the release of sediment into local water systems.\textsuperscript{21} The same effect is possible due to drill pad and pipeline construction.\textsuperscript{22} While such impacts are not certain due to the relatively low level of drilling at this time, road damage and traffic disruption have already been reported in areas where drilling construction has begun.\textsuperscript{23} A study from Denton, Texas where natural gas drilling is occurring in the Barnett Shale revealed that during all three phases of drilling (pad site preparation, fracking, and maintenance) the average number of one-way truck trips was 592/day/well, with some vehicles weighing 100,000 pounds.\textsuperscript{24} “[T]his could be a significant problem if carried out across thousands of active drill sites.”\textsuperscript{25}

**Land conversion and visual impacts**

The area cleared for horizontal wells is about five acres and slightly larger for multi-well pads.\textsuperscript{26} Pipeline easements vary in size from small to many meters;\textsuperscript{27} they are often thirty feet wide for gathering lines and sixty feet for transmission lines.\textsuperscript{28} Seismic lines to collect subsurface data about the location of gas deposits typically measure six to nine meters across and run for several miles at 400 to 100 meters apart.\textsuperscript{29} New roads, whether in the form of unmanaged trails or paved paths, are “rarely decommissioned since there is a chance that the energy firm may return to re-activate the well, the public now uses the road and/or the cost of road deactivation and reclamation is too expensive.”\textsuperscript{30}

Clearing swaths of land leads to habitat fragmentation, especially in forested areas, which in turn can introduce invasive species and impact native wildlife.\textsuperscript{31} A study conducted in Alberta, Canada found reductions in populations of species dependent on old-growth forests and continuous forest habitat due to oil and gas drilling.\textsuperscript{32} Cutting large openings into forests can subject trees to sunscald, frost cracking, windthrow, and wind snap, ultimately killing or felling

\textsuperscript{20} dSGEIS at 6-138–139.
\textsuperscript{22} Id.
\textsuperscript{23} Id.; Rural Impact!
\textsuperscript{25} USGS Fact Sheet at 4. See also Sullivan Report, 13.
\textsuperscript{26} dSGEIS at 6-132.
\textsuperscript{27} Id. at 26.
\textsuperscript{30} Id. at 5.
\textsuperscript{31} Woodring at 1.
\textsuperscript{32} Alberta Report at 10.
them.\textsuperscript{33}

The drilling rig for a horizontal well could be 140 feet tall or more and would be in place for four to five weeks for drilling and three to five days for fracturing; multi-well pads would likely have 170-foot rigs.\textsuperscript{34} Other visual features include construction equipment, trucks, compressors, pipe racks, temporary work sheds, lined pits, and tank trucks holding fluids. Longer-term visual impacts include “an assembly of wellhead valves and auxiliary equipment such as meters, a dehydrator, a gas-water separator, a brine tank and a small fire-suppression tank.”\textsuperscript{35}

**High water use and aquifer depletion**

Hydrofracturing can use up to three million gallons of water per treatment, which has caused regional and local water management agencies to question “where such large volumes of water will be obtained and what the possible consequences might be for local water supplies.”\textsuperscript{36} The non-profit organization Clean Water Action reports that several streams in Pennsylvania have dried up due to hydrofracking’s intensive use of water.\textsuperscript{37} The Delaware River Basin Commission is reviewing a request to withdraw 75% of the water from the West Branch of the Upper Delaware River, with potential detrimental impacts on Philadelphia’s water supply as well as on the Upper Delaware generally, which is designated as Special Protection Waters.\textsuperscript{38} Such large water withdrawals are considered a serious cause for concern.\textsuperscript{39}

That being said, the Susquehanna River Basin Commission stated in February 2009 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.”\textsuperscript{40} Gas drilling is expected to consume less than six percent of the total use for water supply, power, and recreation in the Susquehanna River Basin.\textsuperscript{41} Nonetheless, the dSGEIS notes that “[t]he 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.”\textsuperscript{42} In addition, water withdrawals for fracking are considered 100% consumptive; water supplies are not returned to the basin’s hydrological cycle. The dSGEIS spends four pages discussing the impacts associated with improperly controlled water controls.\textsuperscript{43} Impacts include reduced stream flow, degradation of a stream’s best use, aquatic habitat and ecosystem disruption, damage to downstream wetlands, and aquifer depletion.

**Stress on wastewater treatment facilities**\textsuperscript{44}

\begin{footnotesize}
\textsuperscript{33} Woodring at 2.
\textsuperscript{34} dSGEIS at 6-132.
\textsuperscript{35} Id. at 6-133.
\textsuperscript{36} USGS Fact Sheet at 4.
\textsuperscript{38} Id.
\textsuperscript{39} Sullivan Report at 9.
\textsuperscript{40} dSGEIS at 7-21–22.
\textsuperscript{41} Id. at 6-11.
\textsuperscript{42} Id. at 6-10.
\textsuperscript{43} Id. at 6-4–8.
\textsuperscript{44} See the section below on surface water contamination, specifically regarding the elevated TDS levels in the Monongahela River.
\end{footnotesize}
There is concern that local wastewater treatment plants will not be able to accommodate the wastewater resulting from the hydrofracturing process, which, including the added chemicals, can contain “a variety of formation materials, including brines, heavy metals, radionuclides, and organics.” For example, no plant in Pennsylvania can currently remove total dissolved solids, and the most developed technology will not be ready for use until at least 2013. One treatment plant proposed for Athens Township, Pennsylvania would pump water through skim ponds and then filter the water to remove and condense chemicals into sludge to be shipped off-site. The permit application for the plant expresses concern that the sludge will be rendered radioactive waste due to the concentration of “Radium 226, Radium 228, Gross Alpha, and Gross Beta.” Although the state has over 100 years of experience with oil drilling, it was “caught off guard” by the amount of waste produced in Marcellus Shale natural gas drilling. Pennsylvania estimates that, by 2011, natural gas drilling will produce 19 million gallons of wastewater per day in the state alone. High saline levels in some Appalachian rivers have been linked to the disposal of brines from Marcellus Shale drilling. Other methods of disposal, such as reinjection and evaporation from an open tank, do not seem suitable to the Marcellus Shale region due to the high water table and the humid climate. It is possible that drilling companies might release this “flowback” to surface waters as long as the release does not violate the State’s water quality standards established under Section 303(c)(1) of the Clean Water Act. Some states consider wastewater disposal to be the biggest challenge in the drilling process, a challenge that might lead to illegal disposal of waste.

UNEXPECTED IMPACTS

Groundwater contamination

The Congressional Research Service report released on September 9, 2009 examines the nature of natural gas drilling in the Marcellus Shale region. The report contends that while groundwater contamination from improper drilling and casing is a possibility, as it is for any type

45 USGS Fact Sheet at 5.
46 Total dissolved solids and their impact on human and environmental health are explained in more detail below, in the Surface Water Contamination section.
48 Id.
49 Id.
50 Bloom.
51 Id.
52 USGS Fact Sheet at 5.
53 Id.
55 Id.
of drilling, the risk of contamination in the Marcellus region is remote.\textsuperscript{57} First, the shale above groundwater sources is “typically much greater than the height of the fractures induced during hydraulic fracturing.”\textsuperscript{58} Second, engineers want to ensure that the fractures remain in the shale so that saline fluids or brines do not enter the shale and disturb production.\textsuperscript{59}

Nonetheless, the Report goes on to describe a variety of scenarios where groundwater contamination could occur. First, fluid from the drilling well that is pumped back to the surface can contaminate shallow groundwater if the fluids are disposed of improperly. The Report indicates that this potential contamination poses particular risk in the permeable “unconsolidated sand and gravel deposits” in northern Pennsylvania and southern New York because of the short distance from the land surface to the water table.\textsuperscript{60} These water sources are listed as “primary” or “principal” aquifers in New York, meaning they “are highly productive and presently utilized as a significant source of water, or are a potentially abundant water supply.”\textsuperscript{61} Second, fracking fluid can infiltrate domestic water wells that are not cased from the surface or properly constructed. Other processes that can lead to contamination include seismic testing to determine the thickness of shale and improper plugging of an abandoned well.\textsuperscript{62}

The New York City Department of Environmental Protection (NYCDEP) is very concerned about possible groundwater contamination because many aqueducts, tunnels, and reservoirs, which feed the Hudson River and ultimately provide the city’s drinking water, lie within 500 to 1500 vertical feet of the Marcellus Shale formation.\textsuperscript{63} Casing or grouting failures, pipe corrosion, or poor cementing could create pathways between water supply structures and fluids containing brine water, hydrocarbons, heavy metals, radionuclides or other potential contaminants.\textsuperscript{64} It is also possible that chemicals in fracturing fluid may migrate beyond the fracture zone through naturally occurring fractures or induced fractures beyond the target formation.\textsuperscript{65}

The USGS Fact Sheet expresses concern over the possibility of contamination through spills or leaks of fluids or chemical additives as they are transported and handled.\textsuperscript{66} Where the fracking requires three million gallons of water, it will result in about 15,000 gallons of chemicals in the wastewater due to additives.\textsuperscript{67} Indeed, in late 2008 near Parachute, Colorado, about 1.6 million gallons of used fracking fluid leaked from a waste pit, soaked into the ground, and ultimately reached the Colorado River.\textsuperscript{68} Similar leaks have occurred in Utah and New Mexico.\textsuperscript{69} Manhattan Borough President Scott Stringer release a report in February 2009 that

\textsuperscript{57} Id. at 18.
\textsuperscript{58} Id.
\textsuperscript{59} Id.
\textsuperscript{60} Id.
\textsuperscript{61} Id.
\textsuperscript{63} NYSDEP Report, at ES-4.
\textsuperscript{64} Id. at 33.
\textsuperscript{65} Id. at 35.
\textsuperscript{66} USGS Fact Sheet at 4.
\textsuperscript{67} Id.
\textsuperscript{68} Sarah Crean, City Wants Answers, Input on Upstate Drill Plan, City Limits WEEKLY #702, Sept. 21, 2009, http://www.citylimits.org/content/articles/viewarticle.cfm?article_id=3805.
\textsuperscript{69} Id.
listed seven states with “serious incidents of water contamination near hydraulic fracturing drilling sites,” including Alabama, Colorado, Montana, New Mexico, Ohio, Texas and Wyoming. The Penn State Cooperative Extension conducted a study of 200 private water wells in 2007 and found that 8% of such wells have experienced mild to severe impacts from natural gas drilling. The study explains that this figure could be an overestimate due to stricter regulations in the 1980s or an underestimate due to the high volume of waste produced in hydraulic fracturing. “The bottom line is that nobody can state with confidence what the probability is that a gas well will contaminate freshwater supplies.”

Specific examples of groundwater contamination include the following:

1. Wyoming

“The federal Environmental Protection Agency has found evidence of caustic chemicals associated with natural gas production in 11 private water supplies in the state of Wyoming.” In Pavillon, Wyoming residents smelled foul water, and the EPA began an investigation in March 2009. Residents offer other stories linked to the contaminated water including blinded animals, oil slicks on well water, and nervous system disorder. The Agency recommends further testing to determine the source of high levels of arsenic, methane, 2-butoxyethanol, and other chemicals associated with gas drilling. Due to the lack of industry in the area, the drilling is a primary suspect. That being said, no confirmed example in the U.S. has yet scientifically linked fracturing fluids to groundwater contamination.

In 2006, a gas well blew out in Clark, Wyoming, resulting in a 10 million cubic foot plume of contamination—the equivalent of 100 Olympic-sized swimming pools. “The plume has contaminated drinking water aquifers, two private water wells and natural springs with benzene, diesel range organics, and an extensive list of toxic chemicals. The plume is also putting more than 20 downstream drinking water wells at risk.”

2. Pennsylvania

Dangerous levels of methane have been found in private water wells near drilling sites in Dimock, Pennsylvania—up to fifteen square miles from the site in one case and in at least seven

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70 Crean (quoting the Stringer report).
71 Penningroth at 2.
72 Id.
73 Id.
75 Wilber I at 2.
76 Lustgarten I.
77 Wilber I at 2.
78 Id. See also Lustgarten (explaining that the EPA is also considering other culprits such as (1) agricultural activity, although no pesticides were found with the contamination and (2) household cleaners washed down sinks, although such cleaners would have had to migrate not only to wells but also to the aquifer, which is considered unlikely).
79 Lustgarten I.
81 Id.
Pennsylvania counties since 2004. The state hired a full-time inspector just to monitor methane in homeowners’ wells. Methane is not toxic but can cause violent explosions. In addition, “[w]hen methane is found in water supplies, it can also signal that deeply drilled gas wells are linked with drinking water systems.” The regional Pennsylvania Department of Environmental Protection (PADEP) oil and gas manager initially described the situation in Dimock as an anomaly; however, similar problems have occurred in Bradford, Pennsylvania, where PADEP found methane and metals in wells and required the drilling contractor to install water treatment systems at homes with contamination. The methane leaks appear to have been due to nonexistent or poor casing and cementing around the well pipe. Other instances of “methane migration” in Pennsylvania include the following:

1. Bridgeville - two homes exploded due to methane seepage from a well casing failure;
2. Dayton - residents evacuated after a well casing failure;
3. Vandergrift - pressure from new drilling forced gas into abandoned adjacent wells, which percolated to the surface around homes in a heavily populated neighborhood; and
4. Jefferson County - gas collected in a home until it exploded, killing the residents and shooting debris across the road and into trees.

3. Ohio

On December 15, 2007, a family’s house exploded in Bainbridge, Ohio due to methane build-up through a private water well. Nineteen other homes were subsequently evacuated due to high methane levels. The state Division of Mineral Resources Management determined the source of the contamination to be natural gas drilling in the region’s “Clinton” sandstone, a formation of inter-bedded sandstones, siltstones, and shales. The specific causes of the gas invasion included inadequate cementing of the production casing, hydrofracking with minimal cement behind the production casing, and shutting in of the annular space between the surface and production casings.

Surface water contamination

Contaminated surfaces at the drill site can also lead to pollution in surrounding water bodies through runoff after a rainstorm. Such “storm water discharges” are typically regulated

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83 Id.
84 Wilber I at 3.
85 Lustgarten II.
86 Id.
87 Id.
88 Id.
89 Id.
91 Id. at 4.
92 CRS Report at 5.
under the Clean Water Act, but the Energy Policy Act of 2005 exempts oil and gas drilling sites from the Act’s National Pollution Discharge Elimination System (NPDES) requirements.\textsuperscript{93} States, however, can regulate erosion and sedimentation controls under non-federal law.\textsuperscript{94}

In September 2009, aquatic life—including two species under federal endangered species protection—began to rapidly die off in Dunkard Creek, one of the most ecologically diverse streams in Pennsylvania and West Virginia.\textsuperscript{95} Eighteen species of fish and sixteen species of freshwater mussels have been wiped out, although the cause is still unclear.\textsuperscript{96} State and federal investigators initially looked to a mine water treatment facility but are considering nearby Marcellus Shale drilling after finding “extremely high total dissolved solids, or TDS, and chlorides—properties found in wastewater from . . . drilling operations but not mine water.”\textsuperscript{97} As of mid-October 2009, PADEP believes that the underground flow of methane gas well drilling water into a mine was “the primary immediate source” of the fish kill.\textsuperscript{98}

Improper disposal of wastewater led to elevated TDS levels that exceeded the federal safe drinking water standards in the Monongahela River, which is fed by Dunkard Creek, in 2008 and 2009.\textsuperscript{99} Elevated TDS levels affect the taste and odor of water, and are not considered to be a significant health risk.\textsuperscript{100} Nonetheless, PADEP has instructed sewage treatment plants to only accept gas well drilling wastewater as one percent of their daily flow, a reduction of ninety to ninety-five percent.\textsuperscript{101}

General careless operating procedures

“[T]here are risks associated with . . . accidents every step of the way, from leaky pumps and seals, to faulty well casings.”\textsuperscript{102} For example, PADEP issued a cease and desist order on July 10, 2009 to U.S. Energy Development Corporation because of 302 violations over two years.\textsuperscript{103} “The violations include failure to implement measures to prevent accelerated erosion, unpermitted discharges, failure to restore well sites, encroachments into streams and wetlands without obtaining required permits, and failure to plug abandoned wells.”\textsuperscript{104} In August 2009, Exxon-Mobil pleaded guilty to violating the federal Migratory Bird Treaty Act (MBTA) in five states during the past five years.\textsuperscript{105} “About 85 protected birds . . . died after exposure to hydrocarbons in uncovered natural gas well reserve pits and waste water storage facilities at

\textsuperscript{93} NYSDEP Report at 4.
\textsuperscript{94} CRS Report at 28.
\textsuperscript{96} Id.
\textsuperscript{97} Id.
\textsuperscript{98} Id.
\textsuperscript{100} Hopey I.
\textsuperscript{102} Id.
\textsuperscript{103} Wilber I at 3.
\textsuperscript{105} Id.
Exxon-Mobil sites in Colorado, Wyoming, Kansas, Oklahoma and Texas.\textsuperscript{106}

EARTHWORKS, a non-profit organization based in Washington, D.C., has catalogued numerous complaints of health problems associated with coalbed methane drilling in Colorado.\textsuperscript{107} An organizer for the Clark Resource Council in Clark, Wyoming has complained that “[w]e’ve had years of leaking waste pits, illegal dumping of drilling fluids, inadequate engineering, and finally, the blow out, which left us with contaminated drinking water aquifers. Windsor said the contamination plume wouldn't move into private water wells or jump the Creek, and it did both. Now we fear that Windsor will join their predecessors by bankrupting and simply walk away from their mess.”\textsuperscript{108}

Specific examples of problems associated with shale drilling in other parts of the country include the following:

1. Dimock, Pennsylvania

   On Wednesday, September 16, 2009, between six and eight thousand gallons of lubricating fluid used to decrease resistance in the drilling process leaked from a pipe at a drilling site in Dimock, Pennsylvania in two episodes.\textsuperscript{109} The spills consisted of fluid that, according to the material safety data sheet, can cause “headache, dizziness, or other central nervous system effects” in addition to “respiratory irritation . . . chemical pneumonia . . . slurred speech, giddiness and unconsciousness” when inhaled.\textsuperscript{110} The release impacted a wetland area and Stevens Creek, a tributary of the Susquehanna River.\textsuperscript{111} The company, Cabot Oil & Gas Corp., reported a third spill on Tuesday, September 22, 2009.\textsuperscript{112}

   Since 2008, Dimock has seen at least two other spills requiring cleanup; one involved 800 gallons of diesel fuel spilled by operators that threatened a nearby stream, and the other involved an undetermined amount of diesel released when a cement truck slid down a hill.\textsuperscript{113} In addition, PADEP has deactivated four wells and has required testing at over a dozen wells due to high levels of methane and a risk of explosions.\textsuperscript{114} The drilling company has installed systems in homes to remove natural gas or drilling-related contamination from water.\textsuperscript{115}

   On September 25, 2009, PADEP ordered Cabot to halt operations in Susquehanna County out of concern for concern for the company’s drilling processes and the region’s environment.\textsuperscript{116} PADEP allowed Cabot to resume drilling on October 16, 2009 after reviewing

\textsuperscript{106} Id.
\textsuperscript{107} The health concerns relate to everything from air pollution to gas-contaminated drinking water. Health Concerns in Colorado’s Oil and Gas Fields, EARTHWORKS, http://www.earthworksaction.org/Colohealth.cfm.
\textsuperscript{111} Id.
\textsuperscript{112} Id.
\textsuperscript{113} Wilber II.
\textsuperscript{114} Id.
\textsuperscript{115} Id.
the company’s plans to limit future problems and respond to emergencies.\textsuperscript{117}

2. Coos County, Oregon

US District Judge Michael Hogan issued an order in early 2009 directing MasTec Inc., a contractor hired to build a 60-mile long natural gas pipeline, to pay $1.5 million in penalties because of damage caused to streams and rivers, including “fill[ing] streambeds with drilling spoils.”\textsuperscript{118} Residents and environmental groups also faulted the Oregon Department of Environmental Quality for not adequately overseeing and inspecting the project.\textsuperscript{119}

3. Lebanon, New York

On March 18, 2009 a gas well exploded in Lebanon, New York,\textsuperscript{120} the second explosion after the January 1 explosion in Smyrna, New York.\textsuperscript{121} Something ignited the gas when workers were pulling out pipe after drilling at the site.\textsuperscript{122} The flames and black smoke were visible for two miles, and the well area burned for ten hours.\textsuperscript{123} There was no need for evacuation of residents in the area.\textsuperscript{124}

\textsuperscript{119} Id.
\textsuperscript{122} Gifford.
\textsuperscript{123} Id.
\textsuperscript{124} Id.
Appendix E: Federal, State and local Law

Q: What is the Susquehanna River Basin Commission (SRBC)?
A: The SRBC is a federal-interstate compact commission established by the federal government and the states of New York, Pennsylvania, and Maryland. The SRBC is a local agency responsible for managing the Marcellus Shale’s water resources.

Q: What is an environmental assessment?
A: An environmental assessment is a process of evaluating the known or potential environmental consequences of a proposed activity. During the environmental assessment process, agencies are provided with an opportunity to “identify their concerns about an action, provide guidance to the lead agency in making its determination of significance, and help determine whether additional relevant information about potential impacts is needed.”

Q: What is an Environmental Assessment Form (“EAF”)?
A: The EAF is a form specifically developed for SEQR that “provides an organized approach to identifying and assessing the information needed by the lead agency as it makes its determination of significance” The properly completed form will do the following things:
- Describe the action;
- Indicate the location of the proposed action;
- State the purpose of the action; and
- Describe the potential impacts on the environment of the action.

Q: What are some effects of natural gas drilling that we should be worried about?
A: • Water quality & availability
  • Visual and aesthetic impacts
  • Noise levels
  • Pollution – chemicals resulting from the drilling process
  • Endangering the habitats of certain species of birds, fish, etc.

Q: What is the DEC’s policy on mitigating and assessing visual impacts?
A: According to the DEC’s Assessing and Mitigating Visual Impacts Program Policy, facilities “located in visual proximity to sensitive land uses can produce significant visual impacts.” The DEC’s policy and guidance defines what visual and aesthetic impacts are, describes when a visual assessment is necessary and how to review a visual impact assessment, differentiate state and local concerns, and defines avoidance, mitigation and offset measures that eliminate, reduce, or compensate for negative visual effects.

The policy issued by the DEC makes clear that it does not reduce an applicant’s responsibility to local and other state agencies and departments to address aesthetic and visual issues. The DEC’s guidance is meant to “provide a mechanism for complying with the balancing provisions of the State Environmental Quality Review Act with respect to environmental aesthetics.” The policy also helps to define aesthetic concerns of statewide significance from those of local significance. The staff of the DEC is generally responsible for identifying and mitigating impacts to aesthetic resources that have been designated as of state and federal significance. There is a preference to leave resources designated as local to local decision makers because they “are likely to be more familiar with and best
suited to address them.”

**Q: How does the policy work?**

**A:** When an organization applies for a permit approval from the DEC, “staff must evaluate the potential for adverse visual and aesthetic impacts on receptors outside of the facility or property.” When gas drilling sites are potentially within the “viewshed” of an area designated as an aesthetic resource, visual assessments are required before a permit will be approved. If the visual assessment identifies significant visual impacts, then the gas companies will be required to “employ reasonable and necessary measures to either eliminate, mitigate or compensate for adverse aesthetic effects.” Since such measures will be important in helping to reduce the negative visual consequences that gas drilling could create, it is important to understand how the visual assessment process works and what exactly are designated aesthetic resources.

When reviewing an application for a permit, DEC staff have the responsibility of evaluating the potential for negative aesthetic effects on sensitive places. SEQR requires the DEC to mitigate to the maximum extent practicable any significant adverse visual impacts identified during the permit application process. A SEQR analysis requires the balancing the impacts against the cost of the mitigation measures and their practicality.

While reviewing applications, DEC staff must ensure that all aspects of aesthetic and visual concerns are addressed, including impacts from all project components and their operation on all inventoried resources. If DEC discovers an impact, an analysis must yield an equitable level of expectations between the potential significance of the impact, the degree of sophistication of the analysis required of applicant and appropriate level of mitigation strategies. The goal of visual assessment is for DEC to reveal impacts and effective mitigation strategies.

The Department has identified certain basic steps that its staff must take to make sure that concerns are fully reviewed in each permit application:

1. Verify the applicant’s inventory of aesthetic resources.
2. Verify the applicant’s visual assessment, using either graphic viewshed and line-of-sight profile analysis or more sophisticated visual simulations and digital viewshed analysis, as needed.
3. Determine or verify the applicant’s assessment of the potential significance of the impact.
4. Confirm that applicant’s mitigation strategies are reasonable and are likely to be effective, or assure mitigation by requiring the applicant to submit a design that includes the required mitigation, or, impose permit conditions consistent with those mitigation requirements.

**Q: What is the Clean Air Act (CAA)?**

**A:** The CAA refers to a series of regulations designed to enforce regulations to protect the general public from exposure to airborne contaminants that are known to be hazardous to human health. The Act and its subsequent amendment are codified in 42 U.S.C. § 7401 and are federal law covering the entire country.

**Q: Do the states play any role in Clean Air Act (CAA) enforcement?**

**A:** Yes. Under the CAA, states enforce the Act because pollution control problems often require special understanding of local industries, geography, housing patterns, etc. States are not allowed to have weaker pollution controls than those set for the whole country. For example, a state may require a pipeline to comply with overall air quality requirements under the CAA through its state implementation plan (SIP). A SIP “may establish enforceable emission limitations for particular emission sources, permitting programs for the construction of new or modified air pollutant-emitting facilities, and other control
measures applicable to emission sources within the state to ensure that the National Ambient Air Quality Standards will be achieved and maintained within each air quality control region within a state.”

Q: What are compressor stations and their potential risks?

A: The compressor station, also called a pumping station, is the "engine" that powers an interstate natural gas pipeline. As the name implies, the compressor station compresses the natural gas (pumping up its pressure) thereby providing energy to move the gas through the pipeline. Pipeline companies install compressor stations along a pipeline route, typically every 40 to 100 miles. The size of the station and the number of compressors (pumps) varies, based on the diameter of the pipe and the volume of gas to be moved. Nevertheless, the basic components of a station are similar.

Q: Do compressor stations require Clean Air Act (CAA) permits?

A: Compressor stations commonly do “trigger requirements under several CAA sub programs, including the New Source Review (NSR) and Prevention of Significant Deterioration (PSD) program and the permitting program for major stationary sources under Title V of the CAA.

Q: What is the New Source Review (NSR) program?

A: The NSR program applies to new source construction and proposals to conduct major modifications of existing industrial facilities that are located in “non-attainment” areas (i.e., regions with poor air quality that do not satisfy the National Ambient Air Quality Standards).

Q: What is the Prevention of Significant Deterioration (PSD) program?

A: The “Prevention of Significant Deterioration” requirements apply to project proposals that are located in areas which are in “attainment” with applicable National Ambient Air Quality Standards (i.e., ambient air quality in the region surrounding the new or modified source complies with the national standards)."

Q: Will the DEC ever enact regulations without any prior notice?

A: No, not unless there is an emergency and action must be taken to “prevent waste, pollution or to protect correlative rights.” Such emergency provisions are only effective for 15 days. Normal orders, rules, and regulations must be given a public hearing after 10 days notice. 6 NYCRR 550.4.

Accommodation Doctrine

Q: What is the accommodation doctrine and when does the accommodation doctrine apply?

A: The accommodation doctrine is also known as the alternative means doctrine. The doctrine arises when there is a conflict between a land owner who may have surface rights to a property and a gas company which may have subterranean rights to the land. The doctrine balances the rights of a mineral owner and a surface owner in the use of a surface where conflicts arise. In such circumstances, under the doctrine, a lessee may be required to adopt an alternative means by the rules of reasonable usage if: 1) an existing use by the surface owner would otherwise be impaired, and 2) the lessee has alternatives under established industry practices whereby the minerals can be recovered.
In legal terms, the accommodation doctrine applies “in determining whether inverse condemnation of a mineral estate occurs when a governmental entity that owns the surface estate restricts the use of the surface by the mineral owner and lessee. The governmental surface owner bears the burden of proving that the use of the surface by the lessee is not reasonably necessary. This proof may be made by showing that noninterfering and reasonable ways and means of producing the mineral are available, and that their use will permit the surface owner to continue the existing use of the surface.” 32 Tex. Jur. 3d Eminent Domain § 496.

**Well Spacing and Siting**

**Q: How far must a well be from a building under the DEC permits?**

**A:** NYCRR 553.2 stipulates that a well cannot be located:
- closer than 100 feet from any inhabited private home without the owner’s written consent;
- closer than 150 feet from any “public building or area which may be used as a place of resort, assembly, education, entertainment, lodging, trade, manufacture, repair, storage, traffic or occupancy by the public;”
- closer than 75 feet “to the traveled part of any State, county, township, or municipal road or any public street, road or highway;”
- closer than 50 feet from any public river, stream or other body of water

This regulation, which is adopted in the interest of public safety, does not apply to a building or structure which is incident to agricultural use of the land on which it is located, unless such building is used as a private dwelling house or in the business of retail trade. 125

**Q: What are the regulations dealing with well spacing in New York?**

**A:** NYCRR 553.1 outlines well spacing rules in New York. In general, oil and gas wells:
- cannot be located less than 660 feet from any boundary line of the lease, integrated leases or unit,
- and
- cannot be closer than 1,320 feet from any other oil and gas well in the same pool.

Generally, a well with a lease, integrated lease, or unit that uses the New York-Pennsylvania border as one of its boundary lines may not be drilled within 330 feet of the border.

**Q: When must the DEC issue a well spacing unit permit?**

**A:** The DEC must issue a permit if an applicant controls 60% of the acreage and a proposed unit conforms to the Environmental Conservation Law criteria.

**Q: How does the DEC determine spacing unit size?**

**A:** The Environmental Conservation Law establishes criteria for spacing unit sizes and how close the well can be to the unit boundaries. The existence of a particular spacing unit within the parameters of the ECL criteria is determined by the gas company when it seeks the permit to drill.

**Q: Will the DEC ever force a well operator to revise a spacing unit?**

**A:** Yes, under certain circumstances the DEC may modify a unit previously established by a permit or a spacing order after all affected parties have had an opportunity to comment. Such Department-initiated modifications are very rare. However, when an operator, in accordance with the pooling

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125 Environmental Conservation Law, §§ 23-0301, 23-0305[8], 23-0501
clause in its lease, forms a voluntary unit that is different from the spacing unit established under the Environmental Conservation Law, the DEC may issue a well permit.

Operators are not required to inform the DEC of voluntary units, and the DEC does not track them. However, only the spacing units established by DEC permits and orders are recognized for the purposes of compulsory integration and future well permitting in a given area.\footnote{http://www.dec.ny.gov/}
Appendix F: Acronyms and Glossary

Acronyms

CWA: ........................................................................................................... Clean Water Act
CAA: ........................................................................................................... Clean Air Act
DEC: .................................................................................................................. NYS Department of Environmental Conservation
DOT: .................................................................................................................. United States Department of Transportation
DPS: ........................................................................................................................... Department of Public Services
DRBS: .................................................................................................................. Delaware River Basin Commission
DSGEIS: ........................................................................................................... Draft Supplemental Generic Environmental Impact Statement
EAF: ..................................................................................................................... Environmental Assessment Form
EIS: ..................................................................................................................... Environmental Impact Statement
EPA: ................................................................................................................... Environmental Protection Agency
FERC: ................................................................................................................ Federal Energy Regulatory Commission
FOIL: .................................................................................................................. Freedom of Information Law
FSGEIS: ........................................................................................................... Final Supplemental Generic Environmental Impact Statement
IMP: .................................................................................................................. Integrity Management Program
NOI: .................................................................................................................. Notice of Intent
NORMS: ........................................................................................................... Naturally Occurring Radioactive Materials
NPDES: ........................................................................................................... National Pollutant Discharge Elimination System
NRDC: ............................................................................................................ Natural Resources Defense Council
OSHA: .............................................................................................................. Occupational Safety and Health Administration
PHMSA: ........................................................................................................ Pipeline and Hazardous Material Safety Administration
PIPESA: ............................................................................................................ Pipeline Inspection, Protection, Enforcement and Safety Act
PSC: ................................................................................................................... Public Service Commission
SDWA: ............................................................................................................. Safe Drinking Water Act
SEQR: ................................................................................................................ State Environmental Quality Review Act
SGEIS: ........................................................................................................... Supplemental Generic Environmental Impact Statement
SPDES: ............................................................................................................ State Pollutant Discharge Elimination System
SRBC: ............................................................................................................... Susquehanna River Basin Commission
UIC: .................................................................................................................. Underground Injection Control
USC: ................................................................................................................... Upper Susquehanna Coalition

Glossary

Access Roads
Compensation
Compulsory Integration
Compulsory Integration Hearings
Condemnation
Correlative Rights
Devonian Black Shale
Dispute Arbitration
Drill Sites
Easement
Eminent Domain
Environmental Assessment and Environmental Assessment Form
Gas Lease
Gas reservoirs
Gathering lines
Hydrofracking
Injection Wells
Landmen
Lease Terms
Mineral Rights
Non-Participating Owners
Pooling
Pounds per square inch (PSI)
Production Unit
Rights-of-way
Royalties
Service Lines
Shut-in Royalty
Spacing units
Supplemental Generic Environmental Assessment Statement
Takings
Termination
Transmission lines
Underground Gas Storage
Vacuum pumps
Viewshed
Water use
Well casings
Well platform
Well plugging
Well spacing
Appendix G: Technical Resources

Albany County
Soil & Water Conservation District
Box 497, 24 Martin Road
Voorheesville, NY 12186
Phone: (518) 765-7923
Fax: (518) 765-2490
Email: susan.lewis@ny.nacdnet.net

Allegany County
Soil & Water Conservation District
Ag Service Center
5425 County RT. 48
Belmont, NY 14813-9758
Phone: (585) 268-7831, Ext. 3
Fax: (585) 268-7224
Email: alleganyswcd@hotmail.com

Broome County
Soil & Water Conservation District
1163 Front Street
Binghamton, NY 13905
Phone: (607) 724-9268
Fax: (607) 723-1015
Email: broomesoil@juno.com

Cattaraugus County
Soil & Water Conservation District
8 Martha Street, PO Box 1765
Ellicottville, NY 14731
Phone: (716) 699-2326/2327
Fax: (716) 699-5506
Email: briandavis47@hotmail.com

Cayuga County
Soil & Water Conservation District
7413 County House Road
Auburn, NY 13021
Phone: (315) 252-4171/0793
Fax: (315) 252-1900
Email: cayugaswcd@cayugaswcd.org

Chautauqua County
Soil & Water Conservation District
Frank W. Bratt Ag Center
3542 Turner Road
Jamestown, NY 14701-9605
Phone: (716) 664-2355 Ext. 3
Fax: (716) 483-0773
Email: chaut-co@soilwater.org

Chemung County
Soil & Water Conservation District
851 Chemung St.
Horseheads, NY 14845
Phone: (607) 739-2009/4392
Fax: (607) 739-4392
Email: karentillotson@stny.rr.com

Chenango County
Soil & Water Conservation District
99 North Broad St
Norwich, NY 13815-1388
Phone: (607) 334-4632/8634
Fax: (607) 336-2918
Email: vicki.reynolds@frontiernet.net