Exhibit 75, part 4

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of:	
Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 4

New York Department of Environmental Conservation's Revised Draft Supplemental General Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (September 2011)

January 27, 2012

New York State Department of Environmental Conservation

Revised Draft

Supplemental Generic Environmental Impact Statement

On The Oil, Gas and Solution Mining

Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

Lead Agency:

NYSDEC, 625 Broadway, Albany, NY 12233

Lead Agency Contact:

Eugene Leff
NYSDEC, 625 Broadway, 14th Floor
Albany, NY 12233
(518) 402-8044

Action Location: **Statewide**

Comments Due By: **December 12, 2011**

Prepared By:

NYSDEC, with Assistance from Alpha Environmental, Inc., Ecology and Environment Engineering, P.C., ICF International, URS Corp, NTC Consultants and Sammons/Dutton LLC.

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REVISED DRAFT

Supplemental Generic Environmental Impact Statement

On The Oil, Gas and Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling And High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

Prepared By:

NYSDEC DIVISION OF WATER

NYSDEC DIVISION OF AIR RESOURCES

NYSDEC DIVISION OF LANDS AND FORESTS

NYSDEC DIVISION OF FISH, WILDLIFE & MARINE RESOURCES

Coordinated and Edited By:

NYSDEC DIVISION OF MINERAL RESOURCES

Assisted By:

Ecology and Environment Engineering, P.C.

NEW YORK STATE ENERGY RESEARCH & DEVELOPMENT AUTHORITY*

NEW YORK STATE DEPARTMENT OF HEALTH
Bureau of Water Supply Protection
Bureau of Toxic Substance Assessment
Bureau of Environmental Radiation Protection

NYSDEC OFFICE OF CLIMATE CHANGE
NYSDEC DIVISION OF MATERIALS MANAGEMENT
NYSDEC DIVISION OF ENVIRONMENTAL PERMITS
NYSDEC DIVISION OF ENVIRONMENTAL REMEDIATION

* NYSERDA research assistance for September 2009 draft SGEIS contracted to Alpha Environmental Inc., ICF International, URS Corporation and NTC Consultants. NYSERDA research assistance for 2011 revised draft contracted to Alpha Geological Services, Inc., URS Corporation, NTC Consultants and Sammons/Dutton LLC.

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New York State

DEC

Executive Summary

Revised Draft
Supplemental Generic Environmental Impact Statement

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EXECUTIVE SUMMARY

High-volume hydraulic fracturing is a well stimulation technique that has greatly increased the ability to extract natural gas from very tight rock. High-volume hydraulic fracturing, which is often used in conjunction with horizontal drilling and multi-well pad development, is an approach to extracting natural gas in New York that raises new, potentially significant, adverse impacts not studied in 1992 in the Department of Environmental Conservation's (Department or DEC) previous Generic Environmental Impact Statement (1992 GEIS) on the Oil, Gas and Solution Mining Regulatory Program.[1] Increased production of domestic natural gas resources from deep underground shale deposits in other parts of the country has dramatically altered future energy supply projections and has the promise of lowering costs for users and purchasers of this energy commodity.

High-volume hydraulic fracturing is distinct from other types of well completion that have been allowed in the State under the 1992 GEIS and Department permits due to the much larger volumes of water and additives used to conduct hydraulic fracturing operations. The use of high-volume hydraulic fracturing with horizontal well drilling technology provides for a number of wells to be drilled from a single well pad (multi-pad wells). Although horizontal drilling results in fewer well pads than traditional vertical well drilling, the pads are larger and the industrial activity taking place on the pads is more intense. Also, hydraulic fracturing requires chemical additives, some of which may pose hazards when highly concentrated. The extra water associated with such drilling may also result in significant adverse impacts relating to water supplies, wastewater treatment and disposal and truck traffic. Horizontal wells also generate greater volumes of drilling waste (cuttings). The industry projections of the level of drilling, as

[1] The Generic Environmental Impact Statement (1992 GEIS) on the Oil, Gas and Solution Mining Regulatory Program is posted on the Department's website at http://www.dec.ny.gov/energy/45912.html. The 1992 GEIS includes an analysis of impacts from vertical gas drilling as well as hydraulic fracturing. Since 1992 the Department has used the 1992 GEIS as the basis of its State Environmental Quality Review Act (SEQRA) review for permit applications for gas drilling in New York State.

reflected in the intense development activity in neighboring Pennsylvania, has raised additional concerns relating to community character and socioeconomics.

General Background

In New York, the primary target for shale-gas development is currently the Marcellus Shale, with the deeper Utica Shale also identified as a potential resource. Additional low-permeability reservoirs may be considered by project sponsors for development by high-volume hydraulic fracturing. The Department has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus Shale for natural gas production by high-volume hydraulic fracturing.

The Department has prepared this revised draft Supplemental Generic Environmental Impact Statement (draft SGEIS, dSGEIS, or draft Supplement) to satisfy the requirements of the State Environmental Quality Review Act (SEQRA) by studying the new technique and identifying potential new significant adverse impacts for these anticipated operations. Additionally, the Department prepared this draft SGEIS to satisfy the requirements of the SEQRA for the future enactment of revisions or additions to the Department's regulations associated with high-volume hydraulic fracturing. In reviewing and processing permit applications for high-volume hydraulic fracturing in these deep, low-permeability formations, the Department would apply the requirements contained within regulations, along with the final SGEIS and the findings drawn from it, including criteria and conditions for future approvals, in conjunction with the 1992 GEIS.

The final SGEIS will apply statewide, except in areas that the Department proposes should be off-limits to surface drilling for natural gas using high-volume hydraulic fracturing technology. As explained below, these areas include the watersheds associated with unfiltered water supplied to the New York City and Syracuse areas pursuant to Filtration Avoidance Determinations issued by the U.S. Environmental Protection Agency (EPA), reforestation areas, wildlife management areas, and "primary" aquifers as defined by State regulations, and additional setback and buffer areas. Forest Preserve land in the Adirondacks and Catskills is already off-limits to natural gas development pursuant to the New York State Constitution.

SEQRA Procedure to Date

The public process to develop the dSGEIS began with public scoping sessions in the autumn of 2008. Since then, engineers, geologists and other scientists and specialists in all of the Department's natural resources and environmental quality programs have collaborated to comprehensively analyze a vast amount of information about the proposed operations and the potential significant adverse impacts of these operations on the environment, identify mitigation measures that would prevent or minimize any significant adverse impacts, and identify criteria and conditions for future permit approvals and other regulatory action.

In September 2009, the Department issued a dSGEIS (2009 dSGEIS) for public review and comment. The extensive public comments revealed a significant concern with potential contamination of groundwater and surface drinking water supplies that could result from this new technology. Concerns raised included comments that the 2009 dSGEIS did not fully study the potential for gas migration from this new stimulation technique, or adequately consider impacts from disposal of solid and liquid wastes. Additionally, commenters stated the 2009 dSGEIS did not contain sufficient consideration of visual, noise, traffic, community character or socioeconomic impacts. Accordingly, in 2010 Governor Paterson ordered the Department to issue a revised dSGEIS on or about June 1, 2011. The Executive Order also provided that no permits authorizing high-volume hydraulic fracturing would be issued until the SGEIS was finalized.

Since the issuance of the 2009 draft SGEIS, the Department has gained a more detailed understanding of the potential impacts associated with horizontal drilling from: (i) the extensive public comments from environmental organizations, municipalities, industry groups and other members of the public; (ii) its review of reports and studies of proposed operations prepared by industry groups; (iii) extensive consultations with scientists in several bureaus within the New York State Department of Health (NYSDOH); (iv) the use of outside consulting firms to prepare analyses relating to socioeconomic impacts, as well as impacts on community character, visual, noise and traffic impacts; and, (v) its review of information and data from the Pennsylvania Department of Environmental Protection (PADEP) and the Susquehanna River Basin Commission (SRBC) about events, regulations, enforcement and other matters associated with

ongoing Marcellus Shale development in Pennsylvania. In June 2011, moreover, Commissioner Joseph Martens and Department staff visited a well pad in LeRoy, Pennsylvania, where contaminants had discharged from the well pad into an adjacent stream, and had further conversations with industry representatives and public officials about that event and high-volume hydraulic fracturing operations in Pennsylvania generally.

The Draft SGEIS

The draft SGEIS contains revised and additional analyses relating to high-volume hydraulic fracturing operations compared to the 2009 dSGEIS and the preliminary draft released earlier this year. The draft SGEIS, which is summarized below, supersedes those earlier versions and the expectation is that public comment will focus on the revisions made since the 2009 dSGEIS. For ease of comparison by the public, this document underscores revised or additional discussion from the 2009 draft, and indicates where text from the 2009 draft has been omitted.

Chapter 1 – Introduction

This Chapter contains an introduction to the dSGEIS. The Chapter summarizes the changes in high-volume hydraulic fracturing operations seen since the 2009 SGEIS, describes the methodology of this environmental review, and highlights enhanced mitigation and new precautionary measures incorporated into the document.

Chapter 2 – Description of Proposed Action

This Chapter includes a discussion of the purpose, public need and benefit of proposed high-volume hydraulic fracturing operations, as well as the potential locations, projected activity levels and environmental setting for such operations. Information on the environmental setting focuses on topics determined during scoping to require attention in the SGEIS. The Department has determined, based on industry projections, that it may receive applications to drill approximately 1,700 - 2,500 horizontal and vertical wells for development of the Marcellus Shale by high-volume hydraulic fracturing during a “peak development” year. An average year may see 1,600 or more applications. Development of the Marcellus Shale in New York may occur over a 30-year period. Those peak and average levels of development are the assumptions

upon which the analyses contained in this dSGEIS are based. A consultant to the Department has completed a draft estimate of the potential economic and public benefits of proposed high-volume hydraulic fracturing development, including an analysis based on an average development scenario as well as a more conservative low potential development scenario. That analysis calculates for each scenario the total economic value to the proposed operations, potential state and local tax revenue, and projected total job creation.

Chapter 3 – Proposed SEQRA Review Process

This Chapter describes how the Department intends to use the 1992 GEIS and the final SGEIS in reviewing applications to conduct high-volume hydraulic fracturing operations in New York State. It describes the proposed Environmental Assessment Form (EAF) addendum requirements that would be used in connection with high-volume hydraulic fracturing applications, and also identifies those potential activities that would require site-specific SEQRA determinations of significance after the SGEIS is completed. Specifically, Chapter 3 states that site-specific environmental assessments and SEQRA determinations of significance would be required for the following types of high-volume hydraulic fracturing applications, regardless of the target formation, the number of wells drilled on the pad and whether the wells are vertical or horizontal:

1) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone is shallower than 2,000 feet along a part of the proposed length of the wellbore;

2) Any proposed high-volume hydraulic fracturing 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;

3) Any proposed well pad within the boundaries of a principal aquifer, or outside but within 500 feet of the boundaries of a principal aquifer;

4) Any proposed well pad within 150 feet of a perennial or intermittent stream, storm drain, lake or pond;

5) A proposed surface water withdrawal that is found not to be consistent with the Department's preferred passby flow methodology as described in Chapter 7; and

6) Any proposed well location determined by the New York City Department of Environmental Protection (NYCDEP) to be within 1,000 feet of its subsurface water supply infrastructure.

In all of the aforementioned circumstances a site-specific SEQRA assessment is required because such application is either beyond the scope of the analyses contained in this draft SGEIS or the Department has determined that proposed activities in these areas raise environmental issues that necessitate a site-specific review.

Chapter 3 also identifies the Department's oil and gas well regulations, located at 6 NYCRR Part 550, and it discusses the existence of other regulations and mitigation measures described in this draft SGEIS related to high-volume hydraulic fracturing. For a number of these measures, the Department will propose revisions or additions to its regulations. This chapter discusses how proposed revisions and additions to regulations are part of the environmental review of this draft SGEIS and how the State Administrative Procedure Act process for rulemaking will consider additional impacts of these regulatory actions. These two processes will ensure full review of the proposed environmental controls for high-volume hydraulic fracturing.

Chapter 4 - Geology

Chapter 4 supplements the geology discussion in the 1992 GEIS (Chapter 5) with additional details about the Marcellus and Utica Shales, seismicity in New York State, naturally occurring radioactive materials (NORM) in the Marcellus Shale and naturally occurring methane in New York State. Chapter 4 does not contain significant revisions or additions from the 2009 dSGEIS.

Chapter 5 - Natural Gas Development Activities & High-Volume Hydraulic Fracturing

This Chapter comprehensively describes the activities associated with high-volume hydraulic fracturing and multi-well pad drilling, including the composition of hydraulic fracturing additives and flowback water characteristics. It is based on the most recent up-to-date description of proposed activities provided by industry and informed by high-volume hydraulic fracturing operations currently ongoing in Pennsylvania and elsewhere. In this Chapter, the average disturbance associated with a multi-well pad, access road and proportionate infrastructure during the drilling and fracturing stage is estimated at 7.4 acres, compared to the

average disturbance associated with a well pad for a single vertical well during the drilling and fracturing stage, which is estimated at 4.8 acres. As a result of required partial reclamation, the average well pad would generally be reduced to averages of about 5.5 acres and 4.5 acres, respectively, during the production phase.

This Chapter describes the process for constructing access roads, and observes that because most shale gas development would consist of several wells on a multi-well pad, more than one well would be serviced by a single access road instead of one well per access road as was typically the case when the 1992 GEIS was prepared. Therefore, in areas developed by horizontal drilling using multi-well pads, it is expected that fewer access roads as a function of the number of wells would be constructed. Industry estimates that 90% of the wells used to develop the Marcellus Shale would be horizontal wells located on multi-well pads. This method provides the most flexibility to avoid environmentally sensitive locations within the acreage to be developed.

With respect to overall land disturbance from a horizontal drilling, there would be a larger surface area used for an individual multi-well pad. This would be more than offset, however, by the fewer total number of well pads required within a given area and the need for only a single access road and gas gathering system to service multiple wells on a single pad. Overall, there clearly is a smaller total area of land disturbance associated with horizontal wells for shale gas development than that for vertical wells. For example, a spacing of 40 acres per well for vertical shale gas wells would result in, on average, 70 – 80 acres of disturbance for the well pads, access roads and utility corridors (4.8 acres per well) to develop an area of 640 acres. A single well pad with 6 to 8 horizontal shale gas wells could access all 640 acres with only 7 to 8 acres of total land disturbance.

Chapter 5 describes the constituents of drilling mud and the containment of drilling cuttings, through either a lined on-site reserve pit or in a closed-loop tank system. This Chapter also calculates the projected volume of cuttings and the potential for such cuttings to contain NORM.

This Chapter also discusses the hydraulic fracturing process, the composition of fracturing fluid, on-site storage and handling and transport of fracturing additives. The high-volume hydraulic fracturing process involves the controlled use of water and chemical additives, pumped under

pressure into the cased and cemented wellbore. To protect fresh water zones and isolate the target hydrocarbon-bearing zone, hydraulic fracturing does not occur until after the well is cased and cemented, and typically after the drilling rig and its associated equipment are removed from the well pad. Chapter 5 explains that the Department would generally require at least three strings of cemented casing in the well during fracturing operations. The outer string (i.e., surface casing) would extend below fresh ground water and would have been cemented to the surface before the well was drilled deeper. The intermediate casing string, also called protective string, is installed between the surface and production strings. The innermost casing string (i.e., production casing) typically extends from the ground surface to the toe of the horizontal well.

The fluid used for high-volume hydraulic fracturing is typically comprised of more than 98% fresh water and sand, with chemical additives comprising 2% or less of the fluid. The Department has collected compositional information on many of the additives proposed for use in fracturing shale formations in New York directly from chemical suppliers and service companies and those additives are identified and discussed in detail in Chapter 5. It is estimated that 2.4 million to 7.8 million gallons of water may be used for a multi-stage hydraulic fracturing procedure in a typical 4,000-foot lateral wellbore. Water may be delivered by truck or pipeline directly from the source to the well pad, or may be delivered by trucks or pipeline from centralized water storage or staging facilities consisting of tanks or engineered impoundments.

After the hydraulic fracturing procedure is completed and pressure is released, the direction of fluid flow reverses. The well is “cleaned up” by allowing water and excess proppant (typically sand) to flow up through the wellbore to the surface. Both the process and the returned water are commonly referred to as “flowback.” Chapter 5 discusses the volume, characteristics, recycling and disposal of flowback water. The dSGEIS estimates flowback water volume to range from 216,000 gallons to 2.7 million gallons per well, based on a pumped fluid estimate of 2.4 million to 7.8 million gallons.

Finally, Chapter 5 provides estimates of potential gas production from high-volume hydraulic fracturing operations and also discusses waste disposal associated with high-volume hydraulic fracturing operations, including disposal of cuttings, flowback and production brine

Chapter 6 – Potential Environmental Impacts

This chapter identifies and evaluates the potential significant adverse impacts associated with high-volume hydraulic fracturing operations and, like other chapters, should be read as a supplement to the 1992 GEIS.

Water Resources Impacts

Potential significant adverse impacts on water resources exist with regard to water withdrawals for hydraulic fracturing; stormwater runoff; surface spills, leaks and pit or surface impoundment failures; groundwater impacts associated with well drilling and construction; waste disposal and New York City's subsurface water supply infrastructure. During the public scoping process, additional concerns were raised relating to the potential degradation of New York City's surface drinking water supply and potential groundwater contamination from the hydraulic fracturing procedure itself.

Water for hydraulic fracturing may be obtained by withdrawing it from surface water bodies away from the well site or through new or existing water-supply wells drilled into aquifers. Chapter 6 concludes that, without proper controls on the rate, timing and location of such water withdrawals, the cumulative impacts of such withdrawals could cause modifications to groundwater levels, surface water levels, and stream flow that could result in significant adverse impacts, including but not limited to impacts to the aquatic ecosystem, downstream river channel and riparian resources, wetlands, and aquifer supplies.

Using an industry estimate of a yearly peak activity in New York of 2,462 wells, the dSGEIS estimates that high-volume hydraulic fracturing would result in a calculated peak *annual* fresh water usage of 9 billion gallons. Total *daily* fresh water withdrawal in New York has been estimated at about 10.3 billion gallons. This equates to an annual total of about 3.8 trillion gallons. Based on this calculation, at peak activity high-volume hydraulic fracturing would result in increased demand for fresh water in New York of 0.24%. Thus, water usage for high-volume hydraulic fracturing represents a very small percentage of water usage throughout the state. Nevertheless, as noted, the cumulative impact of water withdrawals, if such withdrawals

were temporally proximate and from the same water resource, could potentially be significant. The mitigation measures to ensure that such impacts are prevented are described in Chapter 7, summarized below.

Chapter 6 also describes the potential impacts on water resources from stormwater flow associated with the construction and operation of high-volume hydraulic fracturing well pads. All phases of natural gas well development, from initial land clearing for access roads, equipment staging areas and well pads, to drilling and fracturing operations, production and final reclamation, have the potential to cause water resource impacts during rain and snow melt events if stormwater is not properly managed. Proposed mitigation measures to prevent significant adverse impacts from stormwater runoff are described in Chapter 7.

The dSGEIS concludes that spills or releases in connection with high-volume hydraulic fracturing could have significant adverse impacts on water resources. The dSGEIS identifies a significant number of contaminants contained in fracturing additives, or otherwise associated with high-volume hydraulic fracturing operations. Spills or releases can occur as a result of tank ruptures, equipment or surface impoundment failures, overfills, vandalism, accidents (including vehicle collisions), ground fires, or improper operations. Spilled, leaked or released fluids could flow to a surface water body or infiltrate the ground, reaching subsurface soils and aquifers. Proposed mitigation measures to prevent significant adverse impacts from spills and releases are described in Chapter 7.

Chapter 6 also assesses the potential significant adverse impacts on groundwater resources from well drilling and construction associated with high-volume hydraulic fracturing. Those potential impacts include impacts from turbidity, fluids pumped into or flowing from rock formations penetrated by the well, and contamination from natural gas present in the rock formations penetrated by the well. The dSGEIS concludes that these potential impacts are not unique to horizontal wells or high-volume hydraulic fracturing and are described and fully assessed in the 1992 GEIS. Nevertheless, because of the concentrated nature of the activity on multi-well pads and the larger fluid volumes and pressures associated with high-volume hydraulic fracturing, enhanced procedures and mitigation measures are proposed and described in Chapter 7.

A supporting study for this dSGEIS concludes that it is highly unlikely that groundwater contamination would occur by fluids escaping from the wellbore for hydraulic fracturing. The 2009 dSGEIS further observes that regulatory officials from 15 states recently testified that groundwater contamination as a result of the hydraulic fracturing process in the tight formation itself has not occurred.

The dSGEIS explains that the potential migration of natural gas to a water well, which presents a safety hazard because of its combustible and asphyxiant nature, especially if the natural gas builds up in an enclosed space such as a well shed, house or garage, was fully addressed in the 1992 GEIS. Well construction associated with high-volume hydraulic fracturing presents no new significant adverse impacts with regard to potential gas migration. Gas migration is a result of poor well construction (i.e., casing and cement problems). As with all gas drilling, well construction practices mandated in New York are designed to prevent gas migration. Those practices would also minimize the risk of migration of other formation fluids such as oil or brine.

The dSGEIS acknowledges that migration of naturally-occurring methane from wetlands, landfills and shallow bedrock can also contaminate water supplies independently or in the absence of any nearby oil and gas activities. Section 4.7 of this dSGEIS explains how the natural occurrence of shallow methane in New York can affect water wells unrelated to natural gas development.

Chapters 5 and 6 contain analyses that demonstrate that no significant adverse impact to water resources is likely to occur due to underground vertical migration of fracturing fluids through the shale formations. The developable shale formations are vertically separated from potential freshwater aquifers by at least 1,000 feet of sandstones and shales of moderate to low permeability. In fact, most of the bedrock formations above the Marcellus Shale are other shales. That shales must be hydraulically fractured to produce fluids is evidence that these types of rock formations do not readily transmit fluids. The high salinity of native water in the Marcellus and other Devonian shales is evidence that fluid has been trapped in the pore spaces for hundreds of millions of years, implying that there is no mechanism for discharge of fluids to other formations.

Hydraulic fracturing is engineered to target the prospective hydrocarbon-producing zone. The induced fractures create a pathway to the intended wellbore, but do not create a discharge mechanism or pathway beyond the fractured zone where none existed before. The pressure differential that pushes fracturing fluid into the formation is diminished once the rock has fractured, and is reversed toward the wellbore during the flowback and production phases. Accordingly, there is no likelihood of significant adverse impacts from the underground migration of fracturing fluids.

No significant adverse impacts are identified with regard to the disposal of liquid wastes. Drilling and fracturing fluids, mud-drilled cuttings, pit liners, flowback water and produced brine, although classified as non-hazardous industrial waste, must be hauled under a New York State Part 364 waste transporter permit issued by the Department. Furthermore, as discussed in Chapter 7, any environmental risk posed by the improper discharge of liquid wastes would be addressed through the institution of a waste tracking procedure similar to that which is required for medical waste, even though the hazards are not equivalent. Another concern relates to potential spills as a result of trucking accidents. Information about traffic management related to high-volume hydraulic fracturing is discussed in Chapter 7.

The disposal of flowback water could cause a significant adverse impact if the wastewater was not properly treated prior to disposal. Residual fracturing chemicals and naturally-occurring constituents from the rock formation could be present in flowback water and could result in treatment, sludge disposal, and receiving-water impacts. Salts and dissolved solids may not be sufficiently treated by municipal biological treatment and/or other treatment technologies which are not designed to remove pollutants of this nature. Mitigation measures have been identified that would eliminate any potential significant adverse impact from flowback water or treatment of other liquid wastes associated with high-volume hydraulic fracturing.

The Department is not proposing to alter its 1992 GEIS Finding that proposed disposal wells require individual site-specific review under SEQRA. Therefore, the potential for significant adverse environmental impacts from any proposal to inject flowback water from high-volume hydraulic fracturing into a disposal well would be reviewed on a site-specific basis with

consideration to local geology (including faults and seismicity), hydrogeology, nearby wellbores or other potential conduits for fluid migration and other pertinent site-specific factors.

The 1992 GEIS summarized the potential impacts of flood damage relative to mud or reserve pits, brine and oil tanks, other fluid tanks, brush debris, erosion and topsoil, bulk supplies (including additives) and accidents. Those potential impacts are equally applicable to high-volume hydraulic fracturing operations. Severe flooding is described as one of the few ways that bulk supplies such as additives "might accidentally enter the environment in large quantities." Mitigation measures to ensure that significant adverse impacts from floods do not occur in connection with high-volume hydraulic fracturing operations are identified and recommended in Chapter 7.

Gamma ray logs from deep wells drilled in New York over the past several decades show the Marcellus Shale to be higher in radioactivity than other bedrock formations including other potential reservoirs that could be developed by high-volume hydraulic fracturing. However, based on the analytical results from field-screening and gamma ray spectroscopy performed on samples of Marcellus Shale NORM levels in cuttings are not significant because the levels are similar to those naturally encountered in the surrounding environment. As explained in Chapter 5, the total volume of drill cuttings produced from drilling a horizontal well may be about 40% greater than that for a conventional, vertical well. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad. The potential water resources impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations would arise from the retention of cuttings during drilling, necessitating a larger reserve pit that may be present for a longer period of time, unless the cuttings are directed into tanks as part of a closed-loop tank system.

Impacts on Ecosystems and Wildlife

The dSGEIS has been revised to expand the analysis of the potential significant adverse impacts on ecosystems and wildlife from high-volume hydraulic fracturing operations. Four areas of concern related to high-volume hydraulic fracturing are: (1) fragmentation of habitat; (2)

potential transfer of invasive species; (3) impacts to endangered and threatened species; and (4) use of state-owned lands.

The dSGEIS concludes that high-volume hydraulic fracturing operations would have a significant impact on the environment because such operations have the potential to draw substantial development into New York, which would result in unavoidable impacts to habitats (fragmentation, loss of connectivity, degradation, etc.), species distributions and populations, and overall natural resource biodiversity. Habitat loss, conversion, and fragmentation (both short-term and long-term) would result from land grading and clearing, and the construction of well pads, roads, pipelines, and other infrastructure associated with gas drilling. Partial mitigation of such impacts is identified in Chapter 7.

The number of vehicle trips associated with high-volume hydraulic fracturing, particularly at multi-well sites, has been identified as an activity which presents the opportunity to transfer invasive terrestrial species. Surface water withdrawals also have the potential to transfer invasive aquatic species. The introduction of terrestrial and aquatic invasive species would have a significant adverse impact on the environment.

State-owned lands play a unique role in New York's landscape because they are managed under public ownership to allow for sustainable use of natural resources, provide recreational opportunities for all New Yorkers, and provide important wildlife habitat and open space. Given the level of development expected for multi-pad horizontal drilling, the dSGEIS anticipates that there would be additional pressure for surface disturbance on State lands. Surface disturbance associated with gas extraction could have an impact on habitats on State lands, and recreational use of those lands, especially large contiguous forest patches that are valuable because they sustain wide-ranging forest species, and provide more habitat for forest interior species.

The area underlain by the Marcellus Shale includes both terrestrial and aquatic habitat for 18 animal species listed as endangered or threatened in New York State that are protected under the State Endangered Species Law (ECL 11-0535) and associated regulations (6 NYCRR Part 182). Endangered and threatened wildlife may be adversely impacted through project actions such as clearing, grading and road building that occur within the habitats that they occupy. Certain

species are unable to avoid direct impact due to their inherent poor mobility (e.g., Blanding's turtle, club shell mussel). Certain actions, such as clearing of vegetation or alteration of stream beds, can also result in the loss of nesting and spawning areas.

Mitigation for potentially significant adverse impacts from potential transfer of invasive species or from use of State lands, and mitigation for potential impacts to endangered and threatened species is identified in Chapter 7.

Impacts on Air Resources

Chapter 6 of the dSGEIS provides a comprehensive list of federal and New York State regulations that apply to potential air emissions and air quality impacts associated with the drilling, completion (hydraulic fracturing and flowback) and production phases (processing, transmission and storage). The revised Chapter includes a regulatory assessment of the various air pollution sources and the air permitting process, as well as a supplemental analysis of impacts not addressed in the 2009 dSGEIS. The review of potential air impacts and expanded analyses accounts for information acquired subsequent to the initial review.

As part of the Department's effort to address the potential air quality impacts of horizontal drilling and hydraulic fracturing activities in the Marcellus Shale and other low-permeability gas reservoirs, an air quality modeling analysis was undertaken by DEC's Division of Air Resources (DAR). The analysis identifies the emission sources involved in well drilling, completion and production, and the analysis of source operations for purposes of assessing compliance with applicable air quality standards.

Since September 2009 industry has provided information that: (1) simultaneous drilling and completion operations at a single pad would not occur; (2) the maximum number of wells to be drilled at a pad in a year would be four in a 12-month period; and (3) centralized flowback impoundments, which are large volume, lined ponds that function as fluid collection points for multiple wells, are not contemplated. Based on these operational restrictions, the Department revised the limited modeling of 24 hour PM2.5 impacts and conducted supplemental air quality modeling to assess standards compliance and air quality impacts. In addition, the Department conducted supplemental modeling to account for the promulgation of new 1 hour SO_2 and NO_2

National Ambient Air Quality Standards (NAAQS) after September 2009. The results of this supplemental modeling indicate the need for the imposition of certain control measures to achieve the NO_2 and PM2.5 NAAQS. These measures, along with all other restrictions reflecting industry's proposed operational restrictions and recommended mitigation measures based on the modeling results, are detailed in Section 7.5.3 of the dSGEIS as proposed operation conditions to be included in well permits. The Department also developed an air monitoring program to fully address potential for adverse air quality impacts beyond those analyzed in the dSGEIS, which are either not fully known at this time or not verifiable by the assessments to date. The air monitoring plan would help determine and distinguish both the background and drilling related concentrations of pertinent pollutants in the ambient air.

Air quality impact mitigation measures are further discussed in Chapter 7 of the dSGEIS, including a detailed discussion of pollution control techniques, various operational scenarios and equipment that can be used to achieve regulatory compliance, and mitigation measures for well pad operations. In addition, measures to reduce benzene emissions from glycol dehydrators and formaldehyde emissions from off-site compressor stations are provided.

Greenhouse Gas Emission Impacts

All operational phases of proposed well pad activities were considered, and resulting greenhouse gas (GHG) emissions determined in the dSGEIS. Emission estimates of carbon dioxide (CO_2) and methane (CH_4) are included as both short tons and as carbon dioxide equivalents (CO_2e) expressed in short tons for expected exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high-volume hydraulic fracturing. The Department not only quantified potential GHG emissions from activities, but also identified and characterized major sources of CO_2 and CH_4 during anticipated operations so that key contributors of GHGs with the most significant Global Warming Potential (GWP) could be addressed and mitigated, with particular emphasis placed on mitigating CH_4, with its greater GWP.

Socioeconomic Impacts

To assess the potential socioeconomic impacts of high-volume hydraulic fracturing, including the potential impacts on population, employment and housing, three representative regions were selected. The three regions were selected to evaluate how high-volume hydraulic fracturing might impact areas with different production potential, different land use patterns, and different levels of experience with natural gas well development. Region A consists of Broome, Chemung and Tioga County. Region B consists of Delaware, Otsego and Sullivan County, and Region C consists of Cattaraugus and Chautauqua County. Using a low and average rate of development based on industry estimates, high-volume hydraulic fracturing will have a significant positive economic effect where the activity takes place. At the maximum rate of well construction, total direct construction employment is predicted to range from 4,408 construction jobs under the low development scenario to 17,634 jobs under the average scenario. An additional 29,174 jobs are predicted to result indirectly from the introduction of high-volume hydraulic fracturing statewide.

There will also be positive impacts on income levels in the state as a result of high-volume hydraulic fracturing. When well construction reaches its maximum levels, total annual construction earnings are projected to range from $298.4 million under the low development scenario to nearly $1.2 billion under the average development scenario. Employee earnings from operational employment are expected to range from $121.2 million under the low development scenario to $484.8 million under the average development scenario in Year 30. Indirect employee earnings are anticipated to range from $202.3 million under the low development scenario to $809.2 million under the average development scenario in Year 30. The total direct and indirect impacts on employee earnings are projected to range from $621.9 million to $2.5 billion per year at peak production and construction levels in Year 30. Chapter 6 details how the potential job creation and employee earnings might be distributed across the three representative regions.

Chapter 6 also assesses the potential temporary and permanent population impacts on each of the three selected regions, finding that Region A will experience an estimated 1.4% increase in the

region's total population the first decade after high-volume hydraulic fracturing in introduced. Region C is projected to be more modestly impacted by high-volume hydraulic fracturing.

While providing positive impacts in the areas of employment and income, high-volume hydraulic fracturing could cause adverse impacts on the availability of housing, especially temporary housing such as hotels and motels. In Region A, where the use of high-volume hydraulic fracturing is expected to be initially concentrated, there could be shortages of rental housing. High-volume hydraulic fracturing would also bring both positive and negative impacts on state and local government spending. Increased activity will result in large increases in local tax revenues and increases in the receipt of production royalties but would also result in an increased demand for local services, including emergency response services.

Visual, Noise and Community Character Impacts

The construction of well pads and wells associated with high-volume hydraulic fracturing will result in temporary, but adverse impacts relating to noise. In certain areas the construction activity would also result in temporary visual impacts. Mitigation measures to address such impacts are summarized in Chapter 7.

The cumulative impact of well construction activity and related truck traffic would cause impacts on the character of the rural communities where much of this activity would take place. Methods to control simultaneous development within a specific area are discussed in Chapter 7.

Transportation Impacts

The introduction of high-volume hydraulic fracturing has the potential to generate significant truck traffic during the construction and development phases of the well. These impacts would be temporary, but the cumulative impact of this truck traffic has the potential to result in significant adverse impacts on local roads and, to a lesser extent, state roads where truck traffic from this activity is concentrated. It is not feasible to conduct a detailed traffic assessment given that the precise location of well pads is unknown at this time. However, such traffic has the potential to damage roads. Chapter 7 discusses the potential mitigation measures to address such impacts, including the requirement that the applicant develop a Transportation Plan that sets

forth proposed truck routes, surveys road conditions along those routes and requires local road use agreements to address any impacts on local roads.

Additional NORM Concerns

Based upon currently available information it is anticipated that flowback water would not contain levels of NORM of significance, whereas production brine could contain elevated NORM levels. Although the highest concentrations of NORM are in produced waters, it does not present a risk to workers because the external radiation levels are very low. However, the build-up of NORM in pipes and equipment (pipe scale and sludge) has the potential to cause a significant adverse impact because it could expose workers handling (cleaning or maintenance) the pipe to increased radiation levels. Also, wastes from the treatment of production waters may contain concentrated NORM and, if so, controls would be required to limit radiation exposure to workers handling this material as well as to ensure that this material is disposed of in accordance with applicable regulatory requirements.

Seismicity

There is a reasonable base of knowledge and experience related to seismicity induced by hydraulic fracturing. Information reviewed indicates that there is essentially no increased risk to the public, infrastructure, or natural resources from induced seismicity related to hydraulic fracturing. The microseisms created by hydraulic fracturing are too small to be felt, or to cause damage at the ground surface or to nearby wells. Accordingly, no significant adverse impacts from induced seismicity are expected to result from high-volume hydraulic fracturing operations.

Chapter 7 – Mitigation Measures

This Chapter describes the measures the Department has identified that, if implemented, would eliminate or mitigate potentially significant adverse impacts from high-volume hydraulic fracturing operations. A number of significant, new mitigation measures not contained in the 2009 dSGEIS have been identified as follows.

No High-Volume Hydraulic Fracturing Operations in the New York City and Syracuse Watersheds

In April 2010 the Department concluded that due to the unique issues presented by high-volume hydraulic fracturing operations within the drinking watersheds for the City of New York and Syracuse, the SGEIS would not apply to activities in those watersheds. Those areas present unique issues that primarily stem from the fact that they are unfiltered water supplies that depend on strict land use and development controls to ensure that water quality is protected.

The revised analysis of high-volume hydraulic fracturing operations in the revised dSGEIS concludes that the proposed high-volume hydraulic fracturing activity is not consistent with the preservation of these watersheds as an unfiltered drinking water supply. Even with all of the criteria and conditions identified in this dSGEIS, a risk remains that significant high-volume hydraulic fracturing activities in these areas could result in a degradation of drinking water supplies from accidents, surface spills, etc. Moreover, such large scale industrial activity in these areas, even without spills, could imperil EPA's Filtration Avoidance Determinations and result in the affected municipalities incurring substantial costs to filter their drinking water supply. Accordingly, this dSGEIS supports a finding that site disturbance relating to high-volume hydraulic fracturing operations not be permitted in the Syracuse and New York City watersheds or in a protective 4,000 foot buffer area around those watersheds.

No High-Volume Hydraulic Fracturing Operations on Primary Aquifers

Although not subject to Filtration Avoidance Determinations, 18 other aquifers in the State of New York have been identified by the New York State Department of Health as highly productive aquifers presently utilized as sources of water supply by major municipal water supply systems and are designated as "primary aquifers." Because these aquifers are the primary source of drinking water for many public drinking water supplies, the Department recommends in this dSGEIS that site disturbance relating to high-volume hydraulic fracturing operations should not be permitted there either or in a protective 500-foot buffer area around them. Horizontal extraction of gas resources underneath primary aquifers from well pads located outside this area would not significantly impact this valuable water resource.

No High-Volume Hydraulic Fracturing Operations on Certain State Lands

This dSGEIS supports a finding that site disturbance relating to high-volume hydraulic fracturing operations should not be permitted on certain State lands because it is inconsistent with the purposes for which those lands have been acquired. In addition, precluding site disturbance on certain State lands would partially mitigate the significant adverse impacts from habitat fragmentation on forest lands due to high-volume hydraulic fracturing activity. It would preclude the loss of such habitat in the protected State land areas which represent some of the largest contiguous forest patches where high-volume hydraulic fracturing activity could occur. Horizontal extraction of gas resources underneath State lands from well pads located outside this area would not significantly impact this valuable habitat on forested State lands.

No High-Volume Hydraulic Fracturing Operations on Principal Aquifers Without Site-Specific Environmental Review

Principal Aquifers are aquifers known to be highly productive or whose geology suggests abundant potential water supply, but which are not intensively used as sources of water supply by major municipal systems at the present time. In order to mitigate the risk of significant adverse impacts on these important water resources from the risk of surface discharges from high-volume hydraulic fracturing well pads, the dSGEIS proposes that for at least two years from issuance of the final SGEIS, applications for high-volume hydraulic fracturing operations at any surface location within the boundaries of principal aquifers, or outside but within 500 feet of the boundaries of principal aquifers, would require (1) site-specific SEQRA determinations of significance and (2) individual SPDES permits for storm water discharges. The dSGEIS proposes the Department re-evaluate the necessity of this restriction after two years of experience issuing permits in areas outside of the 500-foot boundary.

No High-Volume Hydraulic Fracturing Operations within 2,000 feet of Public Drinking Water Supplies

The dSGEIS seeks to mitigate the risk of significant adverse impacts on water resources from the risk of surface discharges from high-volume hydraulic fracturing well pads by proposing that high-volume hydraulic fracturing operations at any surface location within 2,000 feet of public water supply wells, river or stream intakes and reservoirs should not be permitted. The dSGEIS

proposes that the Department re-evaluate the necessity of this approach after three years of experience issuing permits in areas outside of this setback.

No High-Volume Hydraulic Fracturing Operations in Floodplains or Within 500 Feet of Private Water Wells

In order to address potential significant adverse impacts due to flooding, the dSGEIS supports a finding that the Department not issue permits for high-volume hydraulic fracturing operations at any well pad that is wholly or partially within a 100-year floodplain. In order to ensure that there are no impacts on drinking water supplies from high-volume hydraulic fracturing operations, the dSGEIS also supports a finding that no permits be issued for any well pad located within 500 feet of a private water well or domestic use spring, unless waived by the landowner.

Mandatory Disclosure of Hydraulic Fracturing Additives and Alternatives Analysis

The dSGEIS identifies by chemical name and Chemical Abstract Services (CAS) number, 322 chemicals proposed for use for high-volume hydraulic fracturing in New York. Chemical usage was reviewed by NYSDOH, which provided health hazard information that is presented in the document. In response to public concerns relating to the use of hydraulic fracturing additives and their potential impact on water resources, this dSGEIS adds a new requirement that operators evaluate the use of alternative hydraulic fracturing additive products that pose less potential risk to water resources. In addition, in the EAF addendum a project sponsor must disclose all additive products it proposes to use, and provide Material Safety Data Sheets for those products, so that the appropriate remedial measures can be imposed if a spill occurs. The Department will publicly disclose the identities of hydraulic fracturing fluid additive products and their Material Safety Data Sheets, provided that information which meets the confidential business information exception to the Department's records access program will not be subject to public disclosure.

Enhanced Well Casing

In order to mitigate the risk of significant adverse impacts to water resources from the migration of gas or pollutants in connection with high-volume hydraulic fracturing operations, the dSGEIS adds a requirement for a third cemented "string" of well casing around the gas production wells

in most situations. This enhanced casing specification is designed to specifically address concerns over migration of gas into aquifers.

Required Secondary Containment and Stormwater Controls

In order to mitigate the risk of a significant adverse impact to water resources from spills of chemical additives, hydraulic fracturing fluid or liquid wastes associated with high-volume hydraulic fracturing, secondary containment, spill prevention and storm water pollution prevention are comprehensively addressed for all stages of well pad development. The dSGEIS supports the Department's proposal for a new stormwater general permit for gas drilling operations that would address potential stormwater impacts associated with high-volume hydraulic fracturing operations.

Conditions Related to Disposal of Wastewater and Solid Waste

As provided in the 2009 dSGEIS, to ensure that wastewater from high-volume hydraulic fracturing operation is properly disposed, the Department proposes to require that before any permit is issued the operator have Department-approved plans in place for disposing of flowback water and production brine. In addition, the Department proposes to require a tracking system, similar to what is in place for medical waste, for all liquid and solid wastes generated in connection with high-volume hydraulic fracturing operations.

The dSGEIS also proposes to expand its proposed requirement for closed-loop drilling in order to ensure that no significant adverse impacts related to the disposal of pyrite-rich Marcellus Shale cuttings on-site.

Air Quality Control Measures and Mitigation for Greenhouse Gas Emissions

The dSGEIS identifies additional mitigation measures designed to ensure that emissions associated with high-volume hydraulic fracturing operations do not result in the exceedance of any NAAQS. In addition, the Department has committed to implement local and regional level air quality monitoring at well pads and surrounding areas.

The dSGEIS also identifies mitigation measures that can be required through permit conditions and possibly new regulations to ensure that high-volume hydraulic fracturing do not result in significant adverse impacts relating to climate change. The dSGEIS proposes to require a greenhouse gas emission impacts mitigation plan (the Plan). The Plan must include: a list of best management practices for GHG emission sources for implementation at the permitted well site; a leak detection and repair program; use of EPA's Natural Gas Star best management practices for any pertinent equipment; use of reduced emission completions that provide for the recovery of methane instead of flaring whenever a gas sales line and interconnecting gathering line are available; and a statement that the operator would provide the Department with a copy of the report filed with EPA to meet the GHG Reporting Rule.

Mitigation for Loss of Habitat and Impacts on Wildlife

In order to further mitigate significant adverse impacts on wildlife habitat caused by fragmentation of forest and grasslands on private land, the Department proposes to require that surface disturbance in contiguous forest patches of 150 acres or more and contiguous grassland patches of 30 acres or more within specified Forest and Grassland Focus areas, respectively, be contingent upon site-specific ecological assessments conducted by the permit applicant and implementation of best management practices identified through such assessments.

Other Control Measures

Other important existing and anticipated regulatory requirements and/or permit conditions that would be imposed to ensure that high-volume hydraulic fracturing operations do not cause significant impacts on the environment in New York include:

- Before a permit is issued, Department staff would review the proposed layout of the well site based on analysis of application materials and a site visit. Risky site plans would either not be approved or would be subject to enhanced site-specific construction requirements.

- The Department's staff reviews the proposed casing and cementing plan for each well prior to permit issuance. Permits are not issued for improperly designed wells, and in

the case of high-volume hydraulic fracturing, the as-built wellbore construction would be verified before the operation is allowed to proceed.

- The current dSGEIS proposes to require in most cases fully cemented intermediate casing, with the setting depths of both surface and intermediate casing determined by site-specific conditions.

- Fracturing equipment components would be pressure tested with fresh water, mud or brine prior to the introduction of chemical additives.

- The current dSGEIS requires pressure testing of blowout prevention equipment, the use of at least two mechanical barriers that can be tested, the use of specialized equipment designed for entering the wellbore when pressure is anticipated, and the on-site presence of a certified well control specialist.

- Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.

- The Department has a robust permitting and approval process in place to address any proposals to discharge flowback water or production brine to wastewater treatment plants. The Department would require that before any permit is issued the operator have Department-approved plans in place for disposing of flowback water and production brine. Permission to treat such wastewater at a treatment plant in New York State would not be granted without a demonstrable showing that such wastewater can be properly treated at the plant. Additionally, the Department anticipates that operators would favor reusing flowback water for subsequent fracturing operations as they are now doing in Pennsylvania, so that disposal of flowback would be minimized.

- The Department would require that a Transportation Plan be developed and included with any permit application. That plan would include proposed truck routes and an assessment of road conditions along such routes. Any local road use agreement(s)

would have to be disclosed and the applicant would have to demonstrate that the roads to be used are sufficient to accommodate the proposed truck traffic.

- The Department would consult with local governments and, where appropriate, place limits on the number of wells and/or well pads that can be constructed in a specific area at a single time in order to mitigate potential adverse impacts on community character, tourism and other potential socioeconomic impacts that could result from a concentration of well construction activity in a short period of time within a confined area.

- The Department would also impose measures designed to reduce adverse noise or visual impacts from well construction.

Chapter 8 – Permit Process and Regulatory Coordination

This Chapter explains inter- and intra-agency coordination relative to the well permit process, including the role of local governments and a revised approach to local government notification and consideration of potential impacts of high-volume hydraulic fracturing operations on local land use laws and policies. Unlike the 2009 dSGEIS, the current draft Supplement supports a condition that local governments be given notice in writing of all high-volume hydraulic fracturing applications in the locality. A continuously updated database of local government officials and an electronic notification system would be developed for this purpose.

In addition, the EAF Addendum would require the project sponsor to identify whether the proposed location of the well pad, or any other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies. The project sponsor would also be required to identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s). Where the project sponsor indicates that the location of the well pad, or any other activity under the jurisdiction of the Department, is either consistent with local land use laws, regulations, plans or policies, or is not covered by such local land use laws, regulations, plans or policies, no further review of local land use laws and policies would be required.

In cases where a project sponsor indicates that all or part of their proposed application is inconsistent with local land use laws, regulations, plans or policies, or where the potentially impacted local government advises the Department that it believes the application is inconsistent with such laws, regulations, plans or policies, the Department intends to request additional information in the permit application process to determine whether this inconsistency raises significant adverse environmental impacts that have not been addressed in the SGEIS.

Chapter 9 – Alternative Actions

Chapter 9 discusses the alternatives to well permit issuance that were reviewed and considered by the Department. Chapter 21 of the 1992 GEIS and the 1992 Findings Statement discussed a range of alternatives concerning oil and gas resource development in New York State that included both its prohibition and the removal of oil and gas industry regulation. Regulation as described by the GEIS was found to be the best alternative.

The dSGEIS considers a range of alternatives to the proposed approach for regulating and authorizing high-volume hydraulic fracturing operations in New York. As required by SEQRA, the dSGEIS considers the no action alternative. The Department finds that the no action alternative would not result in any of the significant adverse impacts identified herein, but would also not result in the significant economic and other benefits identified with natural gas drilling by this method. The Department believes that this alternative is not preferable because significant adverse impacts from high-volume hydraulic fracturing operations can be fully or partially mitigated.

The alternatives analysis also considers the use of a phased-permitting approach to developing the Marcellus Shale and other low permeability gas reservoirs, including consideration of limiting and/or restricting resource development in designated areas. As discussed above, the Department proposes to partially adopt this alternative by restricting resource development in the New York City and Syracuse watersheds (plus buffer), public water supplies, primary aquifers and certain state lands. In addition, restrictions and setbacks relating to development in other areas near public water supplies, principal aquifers and other resources as outlined above are recommended. The Department does not believe that resource development should be further

limited by imposing an annual limit on permits issued for high-volume hydraulic fracturing operations. The Department believes any such annual limit would be arbitrary. Rather, the Department proposes to limit permit issuance to match the Department resources that are made available to review and approve permit applications, and to adequately inspect well pads and enforce permit conditions and regulations. Although it is not possible to predict the number of permit applications that will be submitted in any given area, and therefore proscribe the level of activity that any one operator may undertake in those areas, the Department has the ability to respond and adjust to conditions in the field. If it is demonstrated, for example, that the measures in place to mitigate noise impacts do not adequately address the impact of high-volume hydraulic fracturing on a host community, the department retains the option through the permitting process to impose additional conditions on operations, such as phasing of drilling operations on adjacent well pads, to prevent or mitigate cumulative or simultaneous operations from impacting nearby residents.

The dSGEIS also contains a review and analysis of the development and use of "green" or non-chemical fracturing alternatives. The Department finds that the use of environmentally-friendly or "green chemicals" would proceed based on the characteristics of the Marcellus Shale play and other shale plays across the United States, as well as the potential environmental impacts of the development. While more research and approval criteria would be necessary to establish benchmarks for "green chemicals," this dSGEIS adopts this alternative approach where feasible by requiring applicants to review and consider the use of alternative additive products that may pose less risk to the environment, including water resources, and to publicly disclose the chemicals that make up these additives. These requirements may be altered and/or expanded as the use of "green chemicals" begin to provide reasonable alternatives and the appropriate technology, criteria and processes are in place to evaluate and produce "green chemicals."

Chapter 10 – Review of Selected Non-Routine Incidents in Pennsylvania

Chapter 10 discusses a number of widely publicized incidents involving high-volume hydraulic fracturing operations in Pennsylvania that have caused public concern about the safety and potential adverse impacts associated with high-volume hydraulic fracturing operations. The case

studies describe the events and their likely causes, and explains how protective measures currently in place or identified as proposed mitigation measures in this dSGEIS would further minimize the risk of such events occurring should high-volume hydraulic fracturing operations be permitted in New York.

Chapter 11 – Summary of Potential Impacts and Mitigation Measures

Chapter 11 highlights the mitigation measures implemented through the 1992 GEIS and summarizes the impacts and mitigation that are discussed in Chapters 6 and 7.

Next Steps

Following the public comment period for the revised draft SGEIS and the draft regulations, the Department will produce a final SGEIS. The final SGEIS will include summaries of the substantive comments received on both the 2009 draft SGEIS and the revised dSGEIS, along with the Department's responses to such comments. The final SGEIS will also incorporate by reference all volumes of the 1992 GEIS.

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DEC

Chapter 1

Introduction

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Chapter 1 – Introduction

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Chapter 1 INTRODUCTION

The Department of Environmental Conservation (Department) has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus and Utica Shales for natural gas production. To release the gas embedded in the shale formations, wells would undergo a stimulation process known as high-volume hydraulic fracturing. While the horizontal well applications received to date are for proposed locations in Broome, Cattaraugus, Chemung, Chenango, Delaware, and Tioga Counties, the Department expects to receive applications to drill in other areas, including counties where natural gas production has not previously occurred. There is also potential for development of the Utica Shale using horizontal drilling and high-volume hydraulic fracturing in Otsego and Schoharie Counties and elsewhere as shown in Chapter 4. Other shale and low-permeability formations in New York may also be targeted for future application of horizontal drilling and high-volume hydraulic fracturing. The Department has prepared this revised draft Supplemental Generic Environmental Impact Statement (SGEIS) to satisfy the requirements of the State Environmental Quality Review Act (SEQRA) for some of these anticipated operations. In reviewing and processing permit applications for horizontal drilling and hydraulic fracturing in these deep, low-permeability formations, the Department would apply the findings and requirements of the SGEIS, including criteria and conditions for future approvals, in conjunction with the existing Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, issued by the Department in 1992 (1992 GEIS).[1]

1.1 Hydraulic Fracturing and Multi-Well Pad Drilling

Hydraulic fracturing is a well stimulation technique which consists of pumping an engineered fluid system and a propping agent (proppant) such as sand down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock. The fractures serve as pathways for hydrocarbons to move to the wellbore for production. Further information on high-volume hydraulic fracturing, including the composition of the fluid system, is provided in Chapter 5.

[1] The 1992 GEIS is posted on the Department's website at http://www.dec.ny.gov/energy/45912.html.

For environmental review purposes pursuant to SEQRA, stimulation including hydraulic fracturing is considered part of the action of drilling a well. Wells where high-volume hydraulic fracturing is used may be drilled vertically, directionally or horizontally. Multiple wells may be drilled from a common location (multi-well pad or multi-well site).

1.1.1 Significant Changes in Proposed Operations Since 2009

The gas drilling industry has informed the Department of the following changes in its planned operations in New York, based, in part, on experience gained in actively developing the Marcellus Shale in Pennsylvania. These changes are reflected in the assumptions used in this revised draft SGEIS to identify and consider potential significant adverse impacts.

1.1.1.1 Use of Reserve Pits or Centralized Impoundments for Flowback Water

The Department was informed in September 2010 that operators would not routinely propose to store flowback water either in reserve pits on the wellpad or in centralized impoundments.[2] Therefore, these practices are not addressed in this revised draft SGEIS and such impoundments would not be approved without site-specific environmental review.

1.1.1.2 Flowback Water Recycling

The Department was also informed in September 2010 that operators plan to maximize reuse of flowback water for subsequent high-volume hydraulic fracturing operations, with some companies targeting goals of recycling 100% of flowback water.[3] The technologies for accomplishing this have evolved through ongoing Marcellus Shale development in Pennsylvania. The Susquehanna River Basin Commission (SRBC) has confirmed that operators are re-using flowback water.[4] This development has the potential to greatly reduce the volume of flowback water that requires treatment, hauling and disposal, and the related environmental concerns. Fresh water consumption and hauling are also somewhat reduced, but in current practice fresh water still comprises 80-90% of the water used at each well for high-volume hydraulic fracturing.

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[2] ALL Consulting, 2010, pp. 18-19.

[3] ALL Consulting, 2010, pp. 73-76.

[4] Richenderfer, 2010, p. 30.

1.2 Regulatory Jurisdiction

The State of New York's official policy, enacted into law, is "to conserve, improve and protect its natural resources and environment . . . ,"[5] and it is the Department's responsibility to carry out this policy. As set forth in Environmental Conservation Law (ECL) §3-0301(1), the Department's broad authority includes, among many other things, the power to:

- manage natural resources to assure their protection and balanced utilization;
- prevent and abate water, land and air pollution; and
- regulate storage, handling and transport of solids, liquids and gases to prevent pollution.

The Department regulates the drilling, operation and plugging of oil and natural gas wells to ensure that activities related to these wells are conducted in accordance with statutory mandates found in the ECL. In addition to protecting the environment and public health and safety, the Department is also required by Article 23 of the ECL (ECL 23) to prevent waste of the State's oil and gas resources, to provide for greater ultimate recovery of the resources, and to protect correlative rights.[6]

1.3 State Environmental Quality Review Act

As explained in greater detail in Chapter 3, the Department's SEQRA regulations authorize the use of generic environmental impact statements to assess the environmental impacts of separate actions having generic or common impacts. Drilling and production of separate oil and gas wells, and other wells regulated under the Oil, Gas and Solution Mining Law (ECL 23) have common impacts. After a comprehensive review of all the potential environmental impacts of oil and gas drilling and production in New York, the Department finalized a Generic Environmental Impact Statement and issued SEQRA Findings on the regulatory program in 1992 (1992 GEIS). In 2008, the Department determined that some aspects of the current and anticipated application of high-volume hydraulic fracturing, which is often used in conjunction with horizontal drilling and multi-well pad development, warranted further review in the context

[5] Environmental Conservation Law (ECL) §1-0101(1).

[6] Correlative rights are the rights of mineral owners to receive or recover oil and gas, or the equivalent thereof, from their owned tracts without drilling unnecessary wells or incurring unnecessary expense.

of a SGEIS. This revised draft SGEIS discusses high-volume hydraulic fracturing in great detail and describes the potential significant impacts from this activity as well as measures that would fully or partially mitigate the identified impacts. Specific mitigation measures would be adopted as part of the Department's Findings Statement in the event high-volume hydraulic fracturing is authorized pursuant to the studies presented herein.

1.4 Project Chronology

1.4.1 February 2009 Final Scope

The Department released a draft Scope for public review in October 2008, and held public scoping sessions at six venues in the Southern Tier and Catskills in November and December, 2008. A total of 188 verbal comments were received at these sessions. In addition, over 3,770 written comments were received (via e-mail, mail, or written comment card). All of these comments were read and reviewed by Department staff and the Final Scope was completed in February 2009, outlining the detailed analysis required for a thorough understanding of the potentially significant environmental impacts of horizontal drilling and high-volume hydraulic fracturing in low-permeability shale.

1.4.2 2009 Draft SGEIS

The Department released the 2009 draft SGEIS for public review on September 30, 2009 and held public hearings at four venues in New York City (NYC), the Catskills and the Southern Tier in October and November, 2009. Comments were accepted at the hearings verbally and in writing, by postal mail, by e-mail and through a web-based application developed specifically for that purpose. More than 2,500 people attended the Department hearings, and more than 200 verbal comments were delivered by individuals, local government officials, representatives of environmental groups and other organizations and members of the oil and gas industry. The Department also received over 13,000 comments via e-mail, postal mail and the web-based comment system. In addition, transcripts from hearings held by the New York State Assembly, the City of Oneonta, and the Tompkins County Council of Governments on the 2009 draft SGEIS also provided the Department with numerous comments.

1.4.2.1 April 2010 Announcement Regarding Communities with Filtration Avoidance Determinations

On April 23, 2010, then-Commissioner Pete Grannis announced that due to the unique issues related to the protection of NYC and Syracuse drinking water supplies, these watersheds would be excluded from the generic environmental review process.

1.4.2.2 Subsequent Exclusion of Communities with Filtration Avoidance Determinations

The analysis of high-volume hydraulic fracturing conducted since the 2009 draft SGEIS supports a finding that high-volume hydraulic fracturing is not consistent with the preservation of these watersheds as an unfiltered drinking water supply.

1.4.3 Revised Draft SGEIS

On January 1, 2011, Governor Cuomo continued Executive Order No. 41 (EO 41), which had been issued by then-Governor Paterson on December 13, 2010. EO 41 directed the Department to publish a revised draft SGEIS on or about June 1, 2011 and to accept public comment on the revisions for a period of not less than 30 days.

1.4.4 Next Steps

Once the revised draft SGEIS is deemed complete, the public comment period will begin. The Department will address the comments and include summaries of the substantive comments received on both the 2009 draft SGEIS and the revised draft SGEIS, along with the Department's responses in the final SGEIS. The final SGEIS will incorporate all volumes of the 1992 GEIS.

At least 10 days after issuance of the final SGEIS, the Department will issue a written Findings Statement. Chapter 3 presents detailed information about a proposed future SEQRA compliance process.

1.5 Methodology

1.5.1 Information about the Proposed Operations

For the 2009 draft SGEIS, the Department primarily relied on two sources of information regarding the operations proposed for New York: (1) a number of permit applications filed with the Department; and (2) the Independent Oil & Gas Association of New York (IOGA-NY),

which provided the Department with information from operators actively developing the Marcellus Shale in Pennsylvania.

Preliminary review of comments on the 2009 draft SGEIS led Department staff to identify additional technical and operational details needed from industry in order to evaluate and address the comments. In April 2010, Department staff sent a "Notice of Information Needs" to IOGA-NY and to specific exploration/production and service companies that commented on the 2009 draft SGEIS. Again, IOGA-NY coordinated industry's response, which was received in September 2010 (ALL Consulting, 2010).

Department staff also communicated with and reviewed information and data made available from the Pennsylvania Department of Environmental Protection (PADEP) and the SRBC about events, regulations, enforcement and other matters associated with ongoing Marcellus Shale development in Pennsylvania.

1.5.2 Intra-/Inter-agency Coordination

Within the Department, preparation of both the 2009 draft SGEIS and the revised draft SGEIS involved all of the programs listed on the "Acknowledgements" page of each document.[7] Other State agencies also provided assistance. Department staff consulted extensively with New York State Department of Health (NYSDOH) staff, and staff in the Department of Public Service (Public Service Commission, or PSC) assisted with the text describing that Department's jurisdiction and regulation over gas gathering facilities.

1.5.3 Comment Review

Of the nearly 13,300 comments received on the 2009 draft SGEIS, at least 9,830 were identified as various campaigns likely generated by on-line form letters, eleven were unique petitions signed by 31,464 individuals and organizations collectively, and seven were the transcripts of the hearings described in Subsection 1.4.2. Each of the transcripts includes comments from a large number of speakers, some of whom also submitted written comments. These transcripts were treated as official public comments, and all comments received are being given equal

[7] As a result of organizational changes within the Department, the Division of Solid & Hazardous Materials is now the Division of Materials Management.

consideration regardless of the method by which they are received. Department staff read and categorized every transcript and every piece of correspondence received to ensure that all substantive comments would be evaluated.

Although the comment period officially closed on December 31, 2009, the Department accepted all comments submitted through January 8, 2010 to further ensure that all substantive comments would be considered.

Following the comment period for the revised draft SGEIS, Department staff will again review and categorize every comment. Comments on both draft documents will be consolidated, and all programs involved in preparing the revised draft SGEIS will also be involved with developing responses to the summarized comments.

1.6 Layout and Organization

The revised draft SGEIS supplements the existing 1992 GEIS, and does not exhaustively repeat narrative from the 1992 GEIS that remains applicable to well permit issuance for horizontal drilling and high-volume hydraulic fracturing.

1.6.1 Chapters

Chapter 1 is an introduction that explains the context, history and contents of the document, and highlights the enhanced procedures, regulations and mitigation measures incorporated into the document.

Chapter 2 is a description of the proposed action, and includes sections on purpose, public need and benefit, project location and environmental setting that are required by SEQRA. The environmental setting section focuses on topics that arose during the public scoping sessions. For a comprehensive understanding of the environmental setting where high-volume hydraulic fracturing might occur, it is necessary to also consult the 1992 GEIS.

Chapter 3 describes the use of a generic environmental impact statement and the resultant SEQRA review process, identifies those potential projects which would require site-specific SEQRA determinations of significance after the SGEIS is completed, and identifies restricted locations where high-volume hydraulic fracturing would be prohibited.

Chapter 4 supplements the geology discussion in Chapter 5 of the 1992 GEIS with additional details about the Marcellus and Utica Shales, seismicity in New York State, naturally-occurring radioactive materials (NORM) in the Marcellus Shale and naturally-occurring methane in New York State.

Chapter 5 comprehensively describes the activities associated with high-volume hydraulic fracturing and multi-well pad drilling, including the composition of hydraulic fracturing additives and flowback water characteristics.

Chapter 6 describes potential impacts associated with the proposed activity and, like other chapters, should be read as a supplement to the 1992 GEIS.

Chapter 7 describes the enhanced procedures, regulations and proposed mitigation measures that have been identified to fully and/or partially mitigate potential significant adverse impacts from high-volume hydraulic fracturing activities to be covered by the SGEIS and 1992 GEIS for SEQRA purposes.

Chapter 8 explains intra- and interagency coordination involved in the well permitting process, including the role of local governments and an expanded approach to local government notification. Descriptions of other regulatory programs that govern some aspects of the potential activities that were previously distributed among several chapters in the document are also now included in Chapter 8.

Chapter 9 discusses the alternatives to well permit issuance that were reviewed and considered.

Chapter 10 is new in the revised draft SGEIS and provides information on certain non-routine incidents in Pennsylvania where development of the Marcellus Shale by high-volume hydraulic fracturing is currently ongoing.

Chapter 11 is new in the revised draft SGEIS and summarizes the impacts and mitigation discussed in Chapters 6 and 7.

1.6.2 Revisions

Except for the Executive Summary which is entirely new, revisions to the 2009 draft SGEIS text are generally marked by vertical lines in the page margins, and new text is underlined. Revised or new Tables, Figures and Appendices are identified as such in their captions or on their cover pages.

1.6.3 Glossary, Bibliographies and Appendices

The Chapters described above are augmented by 27 Appendices and a lengthy glossary that includes acronyms and technical or scientific terms that appear in the document. References cited throughout the document are listed in a bibliography, and separate bibliographies are included that list the various consultants' sources.

1.7 Enhanced Impact Analyses and Mitigation Measures

The Department has identified numerous enhanced procedures and proposed mitigation measures that are available to address the potential significant environmental impacts associated with well permit issuance for horizontal drilling and high-volume hydraulic fracturing. Only the most significant are listed below. Chapter 7 of this document and the 1992 GEIS in its entirety would need to be consulted for the full range of available and required mitigation practices.

The list presented below does not include analyses and mitigation measures proposed in September 2009 that are superseded by the revised draft SGEIS, or that are no longer relevant because of changes in proposed operations.

1.7.1 Hydraulic Fracturing Chemical Disclosure

The Department's hydraulic fracturing chemical disclosure requirements and public disclosure approach set forth in Chapter 8, combined with the chemical disclosures required from industry for the SGEIS analysis, make the Department's disclosure regime among the most stringent in the country. The Department's regime exceeds the requirements of 22 of the 27 oil and gas producing states reviewed and is on par with the five states currently leading the country on chemical disclosure. Additionally, the enhanced disclosure requirements are equivalent to the proposed requirements of the federal Fracturing Awareness and Responsibility (FRAC) Act of 2011.

1.7.2 Water Well Testing

Prior to drilling, operators would be required to test private wells within 1,000 feet of the drill site to provide baseline information and allow for ongoing monitoring. If there are no wells within 1,000 feet, the survey area would extend to 2,000 feet. Chapter 7 reflects updated recommendations from the NYSDOH regarding what analyses should be conducted.

1.7.3 Water Withdrawal and Consumption

1.7.3.1 2009 Draft SGEIS

Applicants would not only have to follow SRBC and Delaware River Basin Commission (DRBC) protocols for water withdrawal where applicable, but would also be required to adhere to a more stringent and protective passby flow requirement in regards to water withdrawal plans - whether inside or outside of the Susquehanna or Delaware river basins. The intended results of these requirements would be to protect aquatic organisms and their habitats in surface waters.

1.7.3.2 Revised Draft SGEIS

The discussion of passby flow and the required streamflow analysis have been updated based on research and studies conducted after the release of the 2009 draft SGEIS. Additionally, details have been added regarding the Department's methodology for evaluating and determining approvable groundwater withdrawal rates.

1.7.4 Well Control and Emergency Response Planning

Although current practices and requirements have proven effective at countless wells throughout New York State, the Department has responded to the public's heightened concerns regarding well control and emergency response issues by including three significant revisions in the revised draft SGEIS:

- Submission, for review in the permit application, of the operator's proposed blowout preventer use and test plan for drilling and completion;
- Description of the required elements of an emergency response plan (ERP); and
- Submission and on-site availability of an ERP consistent with the SGEIS, including a list of emergency contact numbers for the community surrounding the well pad.

1.7.5 Local Planning Documents

The Department proposes that applicants be required to compare the proposed well pad location to local land use laws, regulations, plans and policies to determine whether the proposed activity is consistent with such local land use laws, regulations, plans and policies. If the applicant or the potentially impacted local government informs the Department that it believes a conflict exists, the Department would request additional information with regard to this issue so it can consider whether significant adverse impacts relating to land use and zoning would result from permit issuance.

1.7.6 Secondary Containment, Spill Prevention and Stormwater Pollution Prevention

The Department proposes to require, via permit condition and/or new regulation, that operators provide secondary containment around all additive staging areas and fueling tanks, manned fluid/fuel transfers and visible piping and appropriate use of troughs, drip pads or drip pans. In addition, drilling and hydraulic fracturing operations would be subject to an activity-specific general stormwater permit that would address industrial activities as well as the construction activities that are traditionally the focus of stormwater permitting for oil and gas well sites. The comprehensive Stormwater Pollution Prevention Plan (SWPPP) would incorporate by reference a Spill Prevention, Control and Countermeasures Plan.

1.7.7 Well Construction

Existing requirements are designed to ensure that surface casing be set deeply enough to not only isolate fresh water zones but also to serve as an adequate foundation for well control while drilling deeper. It is also necessary under existing requirements, to the extent possible, to avoid extending the surface casing into shallow gas-bearing zones. Existing casing and cementing requirements that are incorporated into permit conditions establish the required surface casing setting depth based on the best available site-specific information. Each subsequent installation of casing and cement serves to further protect the surface casing and hence, the surrounding fresh water zones.

1.7.7.1 2009 Draft SGEIS

Proposed well construction enhancements for high-volume hydraulic fracturing included:

- Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool; and

- Required certification prior to hydraulic fracturing of the sufficiency of as-built wellbore construction.

1.7.7.2 Revised Draft SGEIS

Additional well construction enhancements for high-volume hydraulic fracturing that the Department proposes to require pursuant to permit condition and/or regulation are listed below:

- Specific American Petroleum Institute (API) standards, specifications and practices would be incorporated into permit conditions related to well construction. Among these would be requirements to adhere to specifications for centralizer type and for casing and cement quality;

- Fully cemented intermediate casing would be required unless supporting site-specific documentation to waive the requirement is presented. This directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones;

- Additional measures to ensure cement strength and sufficiency would be incorporated into permit conditions, also directly addressing gas migration concerns. Compliance would continue to be tracked through site inspections and required well completion reports, and any other documentation the Department deems necessary for the operator to submit or make available for review; and

- Minimum compressive strength requirements.

    - Minimum waiting times during which no activity is allowed which might disturb the cement while it sets;

    - Enhanced requirements for use of centralizers which serve to ensure the uniformity and strength of the cement around the well casing; and

    - Required use of more advanced cement evaluation tools.

1.7.8 Flowback Water Handling On-Site

The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.

1.7.9 Flowback Water Disposal

Under existing regulations, before a permit is issued, the operator must disclose plans for disposal of flowback water and production brine. Further, in the SGEIS the Department proposes to use a new "Drilling and Production Waste Tracking" process, similar to the process applicable to medical waste, to monitor disposal. Under existing regulations, full analysis and approvals under state water laws and regulations are required before a water treatment facility can accept flowback from high-volume hydraulic fracturing operations. Appendix 22 includes a description and flow chart of the required approval process for discharge of flowback water or production brine from high-volume hydraulic fracturing to a Publicly-Owned Treatment Works (POTW). An applicant proposing discharge to a POTW would be required to submit a treatment capacity analysis for the receiving POTW, and, in the event that the POTW is the primary fluid disposal plan, a contingency plan. Additionally, limits would be established for NORM in POTW influent.

1.7.10 Management of Drill Cuttings

The Department has determined that drill cuttings are solid wastes, specifically construction and demolition debris, under the State's regulatory system. Therefore, the Department would allow disposal of cuttings from drilling processes which utilize only air and/or water on-site, at construction and demolition (C&D) debris landfills, or at municipal solid waste (MSW) landfills, while cuttings from processes which utilize any oil-based or polymer-based products could only be disposed of at MSW landfills. The revised draft SGEIS proposes to require, pursuant to permit conditions and/or regulation, that a closed-loop tank system be used instead of a reserve pit to manage drilling fluids and cuttings for:

- Horizontal drilling in the Marcellus Shale without an acceptable acid rock drainage (ARD) mitigation plan for on-site cuttings burial; and
- Cuttings that, because of the drilling fluid composition used must be disposed off-site, including at a landfill.

Only ARD mitigation plans that do not require long-term monitoring would be acceptable. Examples are provided in Chapter 7.

1.7.11 Emissions and Air Quality

The need to re-evaluate air quality impacts and the applicability of various regulations was raised during the scoping process, with emphasis on the duration of activities at a multi-well pad and the number of internal combustion engines used for high-volume hydraulic fracturing.

1.7.11.1 2009 Draft SGEIS

The following conclusions and requirements were set forth:

- Per United States Environmental Protection Agency (EPA) NESHAPS subpart ZZZZ, the compressor station would have an oxidation catalyst for formaldehyde. This also reduces carbon monoxide (CO) by 90% and Volatile Organic Compounds (VOCs) by 70%;

- Per EPA subpart HH, the glycol dehydrator would have a condenser to achieve a benzene emission of <1 ton per year (Tpy) (if "wet" gas is detected);

- Use of Ultra Low Sulfur Fuel (ULSF) of 15 parts per million (ppm) in all engines would be required;

- Small stack height increases on compressor, vent and dehydrator would be required (if "sour" and "wet" gas encountered for the latter two, respectively);

- All annual and short-term ambient standards (National Ambient Air Quality Standards, or NAAQS) and the Department's toxics thresholds (Annual and Short-Term Guideline Concentrations, or AGCs and SGCs) would be met, except 24-hour PM10/PM2.5 NAAQS due to drilling and hydraulic fracturing engines; and

- Impacts from a nearby pad modeled and indicated no overlap in the calculated "cumulative" impacts on local scale.

The facility definition for permitting was based on Clean Air Act (CAA) 112(n)(4) per EPA guidance at the time, which limits it to "surface area" (i.e., per pad). Annual emissions from all sources were calculated assuming ten wells per pad and resulted in a classification of the emissions as "minor" sources. No final determination was made as to whether non-road engines would be part of "stationary" facility since it was unclear before September 2009 if these would be at the pad more than 12 months.

1.7.11.2 Revised Draft SGEIS

The Department performed substantive additional emissions and air quality analyses, which identified the following mitigation measures that the Department proposes to require through enhanced procedures, permit conditions and/or regulations:

- The diesel fuel used in drilling and completion equipment engines would be limited to ULSF with a maximum sulfur content of 15 ppm;
- There would not be any simultaneous operations of the drilling and completion equipment engines at the single well pad;
- The maximum number of wells to be drilled and completed annually or during any consecutive 12-month period at a single pad would be limited to four;
- The emissions of benzene at any glycol dehydrator to be used at the well pad would be limited to 1 Tpy as determined by calculations with the Gas Research Institute's (GRI) GlyCalc program. If wet gas is encountered, then the dehydrator would have a minimum stack height of 30 feet (9.1 meters) and would be equipped with a control device to limit the benzene emissions to 1 Tpy;
- Condensate tanks used at the well pad would be equipped with vapor recovery systems to minimize fugitive VOC emissions;
- During the flowback phase, the venting of gas from each well pad would be limited to a maximum of 5 million standard cubic feet (MMscf) during any consecutive 12 month period. If "sour" gas is encountered with detected hydrogen sulfide (H_2S) emissions, the height at which the gas would be vented would be a minimum of 30 feet (9.1 meters);
- During the flowback phase, flaring of gas at each well pad would be limited to a maximum of 120 MMscf during any consecutive 12-month period;
- Wellhead compressors would be equipped with Non-Selective Catalytic Reduction (NSCR) controls;
- No uncertified (i.e., EPA Tier 0) drilling or completion equipment engines would be used for any activity at the well sites;
- The drilling engines and drilling air compressors would be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these would be equipped with both particulate traps (Continuously Regenerating Diesel Particulate Filters, or CRDPF) and Selective Catalytic Reduction (SCR) controls. During operations, this equipment would be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation

and/or control measures to demonstrate ambient standard compliance, site-specific information would be provided to the Department for review and concurrence; and

- The completion equipment engines would be limited to EPA Tier 2 or newer equipment. CRDPFs would be required for all Tier 2 engines. SCR control would be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment would be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information would be provided to the Department for review and concurrence.

In addition, the revised draft SGEIS discusses the effect of region-wide emissions on State Implementation Plan (SIP) for Ozone NAAQS and implementation of local and regional level air quality monitoring at well pads and surrounding areas.

1.7.12 Greenhouse Gas Mitigation

All operational phases of well pad activities, and all greenhouse gas (GHG) emission sources are evaluated in both the 2009 draft SGEIS and the current draft. Based on this analysis, the Department proposes in the current draft to require the following controls and mitigation measures, pursuant to permit conditions and/or regulation:

- Implementation by the operator of a Leak Detection and Repair Program;
- Upon request, the operator would be required to provide a copy of data required under federal (EPA) GHG reporting rule;
- Reduced Emissions Completion (REC) would be required whenever a gathering line is already constructed. In addition, two years after issuance of the first permit for high-volume hydraulic fracturing, the Department would evaluate whether the number of wells that can be drilled on a pad without REC should be limited; and
- Implementation of other control technologies when applicable, as described in Chapter 7.

1.7.13 Habitat Fragmentation

The current draft includes a substantially augmented analysis of potential impacts from high-volume hydraulic fracturing on wildlife and habitat. Based on that analysis, two measures that were not included in the 2009 draft SGEIS are proposed as mitigation in the revised draft SGEIS:

- *Grassland Focus Areas on private land* – Surface disturbance in grassland patches comprised of 30 acres or more of contiguous grassland within Grassland Focus Areas would be contingent on the findings of a a site-specific ecological assessment conducted by the permit applicant and implementation of mitigation measures identified as part of such ecological assessment; and

- *Forest Focus Areas on private land* – Surface disturbance in forest patches comprised of 150 acres or more of undisturbed, contiguous forest within Forest Focus Areas would be contingent on a site-specific ecological assessment conducted by the permit applicant and implementation of mitigation measures identified as part of such ecological assessment.

1.7.14 State Forests, State Wildlife Management Areas and State Parks

Surface disturbance associated with high-volume hydraulic fracturing would not be allowed on State-owned lands administered by the Department, including but not limited to State Forests and State Wildlife Management Areas, because it is inconsistent with the suite of purposes for which those lands have been acquired. Current Office of Parks, Recreation and Historic Preservation (OPRHP) policy would impose a similar restriction on State Parks.

1.7.15 Community and Socioeconomic Impacts

Chapter 6 of this revised draft SGEIS includes a significantly expanded discussion of community and socioeconomic impacts, traffic impacts, and noise and visual impacts, with measures that will be implemented by the Department to mitigate these impacts described in Chapter 7.

1.8 Additional Precautionary Measures

In order to safeguard the environment from risks associated with spills or other events that could release contaminants into environmentally sensitive areas, the revised draft SGEIS includes the following prohibitions and mitigation measures for high-volume hydraulic fracturing:

- Well pads for high-volume hydraulic fracturing would be prohibited in the NYC and Syracuse watersheds, and within a 4,000-foot buffer around those watersheds;

- Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing);

- Well pads for high-volume hydraulic fracturing would be prohibited within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing);

- For at least two years from issuance of the first permit for high-volume hydraulic fracturing, proposals for high-volume hydraulic fracturing at any well pad within within 500 feet of principal aquifers, would require (1) site-specific SEQRA determinations of significance and (2) individual State Pollutant Discharge Elimination System (SPDES) permits for stormwater discharges. The Department would re-evaluate the necessity of this approach after two years of experience issuing permits in areas outside of the 500-foot boundary;

- The Department would not issue permits for proposed high-volume hydraulic fracturing at any well pad in 100-year floodplains; and

- The Department would not issue permits for proposed high-volume hydraulic fracturing at any proposed well pad within 500 feet of a private water well or domestic use spring, unless waived by the owner.

New York State

DEC

Chapter 2

Description of Proposed Action

Revised Draft
Supplemental Generic Environmental Impact Statement

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Chapter 2 – Description of Proposed Action

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Chapter 2 DESCRIPTION OF PROPOSED ACTION

The proposed action is the Department's issuance of permits to drill, deepen, plug back or convert wells for horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale and other low-permeability natural gas reservoirs. Wells where high-volume hydraulic fracturing is used may be drilled vertically, directionally or horizontally. The proposed action, however, does not include horizontal drilling where high-volume hydraulic fracturing is not employed. Such drilling is covered under the GEIS.

Hydraulic fracturing is a well stimulation technique which consists of pumping an engineered fluid system and a proppant such as sand down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock. The fractures serve as pathways for hydrocarbons to move to the wellbore for production. High-volume hydraulic fracturing, using 300,000 gallons of water or more per well, is also referred to as "slick water fracturing." An individual well treatment may consist of multiple stages (multi-stage frac). Further information on high-volume hydraulic fracturing, including the composition of the fluid system, is provided in Chapter 5.

Multiple wells may be drilled from a common location (multi-well pad, or multi-well site). The Department may receive applications to drill approximately 1,700 – 2,500 horizontal and vertical wells for development of the Marcellus Shale by high-volume hydraulic fracturing during a "peak development" year. An average year may see 1,600 or more applications. Development of the Marcellus Shale in New York may occur over a 30-year period.[1] More information about these activity estimates and the factors which could affect them is presented in Chapter 5.

This SGEIS is focused on topics not addressed by the 1992 GEIS, with emphasis on potential impacts associated with the large volumes of water required to hydraulically fracture horizontal shale wells using the slick water fracturing technique and the disturbance associated with multi-well sites. An additional aspect of this SGEIS is to consider measures that will be incorporated into revisions or additions to the Department's regulations concerning high-volume hydraulic fracturing.

[1] ALL Consulting, 2010, pp. 7 - 9.

2.1 Purpose

As stated in the 1992 GEIS, a generic environmental impact statement is used to evaluate the environmental effects of a program having wide application and is required for direct programmatic actions undertaken by a state agency. The SGEIS will address new activities or new potential impacts not addressed by the 1992 GEIS and will set forth practices and mitigation designed to reduce environmental impacts to the maximum extent practicable. The SGEIS and its findings will be used to satisfy SEQR for the issuance of permits to drill, deepen, plug back or convert wells for horizontal drilling and high-volume hydraulic fracturing. The SGEIS will also be used to satisfy SEQR for the enactment of revisions or additions to the Department's regulations relating to high-volume hydraulic fracturing.

2.2 Public Need and Benefit

The exploration and development of natural gas resources serves the public's need for energy while providing substantial economic and environmental benefits. Natural gas consumption comprises about 23 percent of the total energy consumption in the United States. Natural gas is used for many purposes: home space and water heating; cooking; commercial and industrial space heating; commercial and industrial processes; as a raw material for the manufacture of fertilizer, plastics, and petrochemicals; as vehicle fuel; and for electric generation. Over 50 percent of the homes in the United States use natural gas as the primary heating fuel. In 2008 U.S. natural gas consumption totaled about 23.2 trillion cubic feet (Tcf), nearly matching the peak consumption of 23.3 Tcf reached in 2000.[2]

New York is the fourth largest natural gas consuming state in the nation using about 1,200 billion cubic feet (Bcf) of natural gas per year and accounting for about five percent of U.S. demand.[3]

In 2008 New York's 4.3 million residential customers used about 393 Bcf of natural gas or 33 percent of total statewide gas use. The State's 394,000 commercial customers used about 292 Bcf or 25 percent of total natural gas use. Natural gas consumption in the residential and commercial sectors in New York represents a larger proportion of the total consumption than

[2] New York State Energy Planning Board, December 2009, p. 7.

[3] New York State Energy Planning Board, December 2009, p. 8.

U.S. consumption for those sectors which is 21 and 13 percent, respectively. The primary use of natural gas in New York for residential and small commercial customers is for space heating and is highly weather sensitive. The State's natural gas market is winter- peaking with over 70 percent of residential and 60 percent of commercial natural gas consumption occurring in the five winter months (November through March).[4]

Since natural gas is a national market, developments nationwide regarding gas supply are critical to the State. U.S. natural gas dry production totaled 20.5 Tcf in 2008, which was 6 percent higher than in 2007. About 98 percent of the natural gas produced in the United States comes from production areas in the lower 48 states. The overall U.S. dry natural gas production has been relatively flat over much of the last ten years. However, in the past few years, there has been a significant shift in gas supplies from conventional or traditional supply areas and sources to unconventional or new supply areas and sources. U.S. natural gas production from traditional, more mature and accessible natural gas supply basins has steadily declined. However, this has been offset by increased drilling and production from new unconventional gas supply areas. In 2008 natural gas production from new supply resources totaled about 10.4 Tcf (28.5 Bcf per day) or about 51 percent of the total U.S. dry natural gas production.[5]

The increased production from unconventional resources is primarily from tight sands, coal-bed methane, and shale formations. The Rocky Mountain Region is the fastest-growing region for tight sands natural gas production and the predominant region for coal-bed methane natural gas production in the United States. There are at least 21 shale gas basins located in over 20 states in the United States. Currently, the most prolific-shale producing areas in the country are in the southern US and include the Barnett Shale area in Texas, the Haynesville Shale in Texas and Louisiana, the Woodford Shale in Oklahoma, and the Fayetteville Shale in Arkansas. In the Appalachian region, which extends into New York, the Marcellus Shale is expected to develop into a major natural gas production area. Proven natural gas reserves for the United States totaled over 237 Tcf at the end of 2007, an increase of about 12 percent over 2006 levels. The

[4] New York State Energy Planning Board, December 2009, p. 8.

[5] New York State Energy Planning Board, December 2009, p. 10.

increase in reserves was the ninth year in a row that U.S. natural gas proven reserves have increased.[6]

Over 95 percent of the natural gas supply required to meet the demands of New York natural gas customers is from other states, principally the Gulf Coast region, and Canada. The gas supply is brought to the New York market by interstate pipelines that move the gas from producing and storage areas for customers, such as local distribution companies (LDCs) and electric generators, who purchase the gas supplies from gas producers and marketers.

New York natural gas production supplies about 5 percent of the State's natural gas requirements. Currently, there are about 6,700 active natural gas wells in the State. For the 2010 calendar year, total reported State natural gas production was 35.7 Bcf, down 35 percent from the 2006 record total of 55.2 Bcf. These figures represent an increase of over 100 percent since 1998 (16.7 Bcf).[7]

The Marcellus Shale formation has attracted great attention as a significant new source of natural gas production. The Marcellus Shale extends from Ohio through West Virginia and into Pennsylvania and New York. In New York, the Marcellus Shale is located in much of the Southern Tier stretching from Chautauqua and Erie Counties in the west to the counties of Sullivan, Ulster, Greene and Albany in the east. According to researchers at Penn State University, the Marcellus Shale is the largest known shale deposit of gas in the world.[8] Engelder and Lash (2008) first estimated gas-in-place to be between 168 and 500 Tcf with a recoverable estimate of 50 Tcf.[9] While it is early in the productive life of Marcellus Shale wells, the most recent estimates by Engelder using well production decline rates indicate a 50 percent probability that recoverable reserves could be as high as 489 Tcf.[10]

In Pennsylvania, where Marcellus Shale development is underway, researchers at Penn State University estimated that the natural gas industry generated $2.3 billion in total value, added

[6] New York State Energy Planning Board, December 2009, p. 12.

[7] New York State Energy Planning Board, August 2009, p.14.

[8] Considine et al., 2009, p.2.

[9] Engelder and Lash, 2008, p.87.

[10] Engelder, 2009, p.5.

more than 29,000 jobs, and $240 million in state and local taxes in 2008. With a substantially higher pace of development projected by these researchers subsequently, they anticipated substantially higher economic output, state and local tax revenues, and job creation.[11]

The Draft 2009 New York State Energy Plan recognizes the potential benefit to New York by development of the Marcellus Shale natural gas resource:

Production and use of in-state energy resources – renewable resources and natural gas – can increase the reliability and security of our energy systems, reduce energy costs, and contribute to meeting climate change, public health and environmental objectives. Additionally, by focusing energy investments on in-state opportunities, New York can reduce the amount of dollars "exported" out of the State to pay for energy resources.[12]

The New York State Energy Plan further includes a recommendation to encourage development of the Marcellus Shale natural gas formation with environmental safeguards that are protective of water supplies and natural resources.[13]

The New York State Commission on State Asset Maximization recommends that "Taking into account the significant environmental considerations, the State should study the potential for new private investment in extracting natural gas in the Marcellus Shale on State-owned lands, in addition to development on private lands." Depending on the geology, a typical horizontal well in the Marcellus Shale (covering approximately 80 acres) may produce 1.0 to 1.5 Bcf of gas cumulatively over the first five years in service. At a natural gas price of $6 per thousand cubic feet (Mcf), a 12.5 percent royalty could result in royalty income to a landowner of $750,000 to over $1 million over a five-year period.[14]

The Final report concludes that an increase in natural gas supplies would place downward pressure on natural gas prices, improve system reliability and result in lower energy costs for New Yorkers. In addition, natural gas extraction would create jobs and increase wealth to

[11]- Considine et al., 2009, p. 30.

[12] New York State Energy Planning Board, December 2009, p. xiv.

[13] New York State Energy Planning Board, December 2009, p.xv.

[14] New York State Commission on State Asset Maximization, June 2009, p. 62.

upstate landowners, and increase State revenue from taxes and landowner leases and royalties. The report also concludes that development of State-owned lands not protected by Article XIV of the State Constitution could provide revenue relief to the State and spur economic development and job creation in economically depressed regions of the State.[15]

Broome County, New York commissioned a study entitled *Potential Economic and Fiscal Impacts from Natural Gas Production in Broome County, New York,* which was released in July 2009. The report details significant potential economic impacts on the Greater Binghamton Region:

Table 2.1 - Economic and Fiscal Impacts of Gas Well Drilling Activities in Broome County, NY Over 10 Years[16]

Description	Impact 2,000 Wells	Impact 4,000 Wells
Total Spending	$ 7,000,000,000	$ 14,000,000,000
Total Economic Activity	$ 7,648,652,000	$ 15,297,304,000
Total Wages, Salaries, Benefits (labor income)	$ 396,436,000	$ 792,872,000
Total Employment (person years)	8,136	16,272
Total Property Income*	$ 605,676,000	$ 1,211,352,000
State Taxes†	$ 22,240,000	$ 44,480,000
Local Taxes†	$ 20,528,000	$ 41,056,000

**Includes royalties, rents, dividends, and corporate profits. † Includes sales, excise, property taxes, fees, and licenses.*

The local economic impacts are already being realized in some cases as exploration companies continue to lease prospective acreage in the Southern Tier and as oil and gas service companies seek to locate in the heart of the activity to better serve their customers. News reports on June 20, 2009, detailed the terms of a lease agreement between Hess Corporation and a coalition of landowners in the Towns of Binghamton and Conklin. The coalition represents some 800 residents who control more than 19,000 acres. The lease provides bonus payments of $3,500 per acre and a royalty of 20 percent. On August 26, 2009, it was reported that in Horseheads, New York, Schlumberger Technology Corporation planned to build a $30 million facility to house

[15] New York State Commission on State Asset Maximization, June 2009, p. 62.

[16] Broome County, 2009, p. 10.

$120 million worth of equipment and technology to service oil and gas exploration companies in the Southern Tier and Northern Pennsylvania. As of June 2011, construction of the Schlumberger CT (coiled tubing) facility was ongoing but the facility was offering some services. Once completed, the facility will comprehensively service horizontal multistage completion needs in the Marcellus Shale. The facility is ideally located to respond to immediate callout and minimize mobilization time and costs. This operations base will be designed to combine CT, cementing, stimulation, and other completion expertise.[17]

According to researchers at Penn State University, natural gas will play a pivotal role in the transformation of our economy to achieve lower levels of GHG emissions. Natural gas has lower carbon emissions than both coal and oil, so that any displacement of these fuels by natural gas to supply power plants and other end-users will produce a reduction in GHG.[18]

In Chapter 6 the potential negative environmental impacts of the proposed action will be systematically identified and discussed. What is clear is that there are significant positive economic consequences along with significant potential impacts on the environment that need to be carefully considered.

2.3 Project Location

The 1992 GEIS is applicable to onshore oil and gas well drilling statewide. Sedimentary rock formations which may someday be developed by horizontal drilling and hydraulic fracturing exist from the Vermont/Massachusetts border up to the St. Lawrence/Lake Champlain region, west along Lake Ontario to Lake Erie and across the Southern Tier and Finger Lakes regions. Drilling will not occur on State-owned lands in the Adirondack and Catskill Forest Preserves because of the State Constitution's requirement that Forest Preserve lands be kept forever wild and not be leased or sold. Drilling will not occur on State reforestation areas and wildlife management areas that are located in the Forest Preserve because the State Constitution prohibits those areas from being leased or sold. Surface disturbance associated with high-volume hydraulic fracturing would not be allowed on State-owned lands administered by DEC outside of the Forest Preserve, including but not limited to State Forests and State Wildlife Management

[17] http://www.slb.com/~/media/Files/coiled_tubing/brochures/usland_ct_br.ashx.

[18] Considine et al., 2009, p. 2.

Areas, because high-volume hydraulic fracturing would be inconsistent with the purposes for which those lands were acquired. Current OPRHP policy would impose a similar restriction on State Parks. In addition, the subsurface geology of the Adirondacks, NYC and Long Island and other factors render drilling for hydrocarbons in those areas unlikely.

The prospective region for the extraction of natural gas from Marcellus and Utica Shales has been roughly described as an area extending from Chautauqua County eastward to Greene, Ulster and Sullivan Counties, and from the Pennsylvania border north to the approximate location of the east-west portion of the New York State Thruway between Schenectady and Auburn. The maps in Chapter 4 depict the prospective area.

2.4 Environmental Setting

Environmental resources discussed in the 1992 GEIS with respect to potential impacts from oil and gas development include: waterways/water bodies; drinking water supplies; public lands; coastal areas; wetlands; floodplains; soils; agricultural lands; intensive timber production areas; significant habitats; areas of historical, architectural, archeological and cultural significance; clean air and visual resources.[19] Further information is provided below regarding specific aspects of the environmental setting for Marcellus and Utica Shale development and high-volume hydraulic fracturing that were determined during Scoping to require attention in the SGEIS.

2.4.1 Water Use Classifications[20]

Water use classifications are assigned to surface waters and groundwaters throughout New York. Surface water and groundwater sources are classified by the best use that is or could be made of the source. The preservation of these uses is a regulatory requirement in New York. Classifications of surface waters and groundwaters in New York are identified and assigned in 6 NYCRR Part 701.

[19] NYSDEC, 1992, GEIS Chapter 6 provides a broad background of these environmental resources, including the then-existing legislative protections, other than SEQRA, guarding these resources from potential impacts. Chapters 8, 9, 10, 11, 12, 13, 14 and 15 of the GEIS contain more detailed analyses of the specific environmental impacts of development on these resources, as well as the mitigation measures required to prevent these impacts.

[20] URS, 2009, p. 4-2.

In general, the discharge of sewage, industrial waste, or other wastes must not cause impairment of the best usages of the receiving water as specified by the water classifications at the location of discharge and at other locations that may be affected by such discharge. In addition, for higher quality waters, the Department may impose discharge restrictions (described below) in order to protect public health, or the quality of distinguished value or sensitive waters.

A table of water use classifications, usages and restrictions follows.

Table 2.2 - New York Water Use Classifications

Water Use Class	Water Type	Best Usages and Suitability	Notes
N	Fresh Surface	1, 2	
AA-Special	Fresh Surface	3, 4, 5, 6	Note a
A-Special	Fresh Surface	3, 4, 5, 6	Note b
AA	Fresh Surface	3, 4, 5, 6	Note c
A	Fresh Surface	3, 4, 5, 6	Note d
B	Fresh Surface	4, 5, 6	
C	Fresh Surface	5, 6, 7	
D	Fresh Surface	5, 7, 8	
SA	Saline Surface	4, 5, 6, 9	
SB	Saline Surface	4, 5, 6,	
SC	Saline Surface	5, 6, 7	
I	Saline Surface	5, 6, 10	
SD	Saline Surface	5, 8	
GA	Fresh Groundwater	11	
GSA	Saline Groundwater	12	Note e
GSB	Saline Groundwater	13	Note f
Other – T/TS	Fresh Surface	Trout/Trout Spawning	
Other – Discharge Restriction Category	All Types	N/A	See descriptions below

Best Usage/Suitability Categories [Column 3 of Table 2.2 above]

1. Best usage for enjoyment of water in its natural condition and, where compatible, as a source of water for drinking or culinary purposes, bathing, fishing, fish propagation, and recreation;

2. Suitable for shellfish and wildlife propagation and survival, and fish survival;

3. Best usage as source of water supply for drinking, culinary or food processing purposes;

4. Best usage for primary and secondary contact recreation;

5. Best usage for fishing;

6. Suitable for fish, shellfish, and wildlife propagation and survival;

7. Suitable for primary and secondary contact recreation, although other factors may limit the use for these purposes;

8. Suitable for fish, shellfish, and wildlife survival (not propagation);

9. Best usage for shellfishing for market purposes;

10. Best usage for secondary, but not primary, contact recreation;

11. Best usage for potable water supply;

12. Best usage for source of potable mineral waters, or conversion to fresh potable waters, or as raw material for the manufacture of sodium chloride or its derivatives or similar products; and

13. Best usage is as receiving water for disposal of wastes (may not be assigned to any groundwaters of the State, unless the Commissioner finds that adjacent and tributary groundwaters and the best usages thereof will not be impaired by such classification).

Notes [Column 4 of Table 2.2 above]

a. These waters shall contain no floating solids, settleable solids, oil, sludge deposits, toxic wastes, deleterious substances, colored or other wastes or heated liquids attributable to sewage, industrial wastes or other wastes; there shall be no discharge or disposal of sewage, industrial wastes or other wastes into these waters; these waters shall contain no phosphorus and nitrogen in amounts that will result in growths of algae, weeds and slimes that will impair the waters for their best usages; there shall be no alteration to flow that will impair the waters for their best usages; there shall be no increase in turbidity that will cause a substantial visible contrast to natural conditions;

b. This classification may be given to those international boundary waters that, if subjected to approved treatment, equal to coagulation, sedimentation, filtration and disinfection with additional treatment, if necessary, to reduce naturally present impurities, meet or will meet NYSDOH drinking water standards and are or will be considered safe and satisfactory for drinking water purposes;

c. This classification may be given to those waters that if subjected to pre-approved disinfection treatment, with additional treatment if necessary to remove naturally present impurities, meet or will meet NYSDOH drinking water standards and are or will be considered safe and satisfactory for drinking water purposes;

d. This classification may be given to those waters that, if subjected to approved treatment equal to coagulation, sedimentation, filtration and disinfection, with additional treatment if necessary to reduce naturally present impurities, meet or will meet NYSDOH drinking water standards and are or will be considered safe and satisfactory for drinking water purposes;

e. Class GSA waters are saline groundwaters. The best usages of these waters are as a source of potable mineral waters, or conversion to fresh potable waters, or as raw material for the manufacture of sodium chloride or its derivatives or similar products; and

f. Class GSB waters are saline groundwaters that have a chloride concentration in excess of 1,000 milligrams per liter (mg/L) or a total dissolved solids (TDS) concentration in excess of 2,000 mg/L; this classification shall not be assigned to any groundwaters of the State, unless the Department finds that adjacent and tributary groundwaters and the best usages thereof will not be impaired by such classification.

Discharge Restriction Categories [Last Row of Table 2.2 above]

Based on a number of relevant factors and local conditions, per 6 NYCRR §701.20, discharge restriction categories may be assigned to: (1) waters of particular public health concern; (2) significant recreational or ecological waters where the quality of the water is critical to maintaining the value for which the waters are distinguished; and (3) other sensitive waters

where the Department has determined that existing standards are not adequate to maintain water quality.

1. Per 6 NYCRR §701.22, new discharges may be permitted for waters where discharge restriction categories are assigned when such discharges result from environmental remediation projects, from projects correcting environmental or public health emergencies, or when such discharges result in a reduction of pollutants for the designated waters. In all cases, best usages and standards will be maintained;

2. Per 6 NYCRR §701.23, except for storm water discharges, no new discharges shall be permitted and no increase in any existing discharges shall be permitted; and

3. Per 6 NYCRR §701.24, specified substances shall not be permitted in new discharges, and no increase in the release of specified substances shall be permitted for any existing discharges. Storm water discharges are an exception to these restrictions. The substance will be specified at the time the waters are designated.

2.4.2 Water Quality Standards

Generally speaking, groundwater and surface water classifications and quality standards in New York are established by the United States Environmental Protection Agency (USEPA) and the Department. The NYC Department of Environmental Protection (NYCDEP) defers to the New York State Department of Health (NYSDOH) for water classifications and quality standards. The most recent NYC Drinking Water Quality Report can be found at http://www.nyc.gov/html/dep/pdf/wsstate10.pdf. The Susquehanna River Basin Commission (SRBC) has not established independent classifications and quality standards. However, one of SRBC's roles is to recommend modifications to state water quality standards to improve consistency among the states. The Delaware River Basin Commission (DRBC) has established independent classifications and water quality standards throughout the Delaware River Basin, including those portions within New York. The relevant and applicable water quality standards and classifications include the following:

- 6 NYCRR Part 703, Surface Water and Groundwater Quality Standards and Groundwater Effluent Limitations;[21]
- USEPA Drinking Water Contaminants;[22]
- 18 CFR Part 410, DRBC Administrative Manual Part III Water Quality Regulations;[23]
- 10 NYCRR Part 5, Subpart 5-1 Public Water Systems;[24] and
- NYCDEP Drinking Water Supply and Quality Report.[25]

2.4.3 Drinking Water[26]

The protection of drinking water sources and supplies is extremely important for the maintenance of public health, and the protection of this water use type is paramount. Chemical or biological substances that are inadvertently released into surface water or groundwater sources that are designated for drinking water use can adversely impact or disqualify such usage if there are constituents that conflict with applicable standards for drinking water. These standards are discussed below.

2.4.3.1 Federal

The Safe Drinking Water Act (SDWA), passed in 1974 and amended in 1986 and 1996, gives USEPA the authority to set drinking water standards. There are two categories of drinking water standards: primary and secondary. Primary standards are legally enforceable and apply to public water supply systems. The secondary standards are non-enforceable guidelines that are recommended as standards for drinking water. Public water supply systems are not required to comply with secondary standards unless a state chooses to adopt them as enforceable standards. New York has elected to enforce both as Maximum Contaminant Levels (MCLs) and does not make the distinction.

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[21] http://www.dec.ny.gov/regs/4590.html.

[22] http://www.epa.gov/safewater/contaminants/index.html.

[23] http://www.state.nj.us/drbc/regs/WQRegs_071608.pdf.

[24] http://www.health.state.ny.us/environmental/water/drinking/part5/subpart5.htm

[25] http://www.nyc.gov/html/dep/html/drinking_water/wsstate.shtml.

[26] URS, 2009, pp. 4-5:4-16.

The primary standards are designed to protect drinking water quality by limiting the levels of specific contaminants that can adversely affect public health and are known or anticipated to occur in drinking water. The determinations of which contaminants to regulate are based on peer-reviewed science research and an evaluation of the following factors:

- Occurrence in the environment and in public water supply systems at levels of concern;
- Human exposure and risks of adverse health effects in the general population and sensitive subpopulations;
- Analytical methods of detection;
- Technical feasibility; and
- Impacts of regulation on water systems, the economy and public health.

After reviewing health effects studies and considering the risk to sensitive subpopulations, EPA sets a non-enforceable Maximum Contaminant Level Goal (MCLG) for each contaminant as a public health goal. This is the maximum level of a contaminant in drinking water at which no known or anticipated adverse effect on the health of persons would occur, and which allows an adequate margin of safety. MCLGs only consider public health and may not be achievable given the limits of detection and best available treatment technologies. The SDWA prescribes limits in terms of MCLs or Treatment Techniques (TTs), which are achievable at a reasonable cost, to serve as the primary drinking water standards. A contaminant generally is classified as microbial in nature or as a carcinogenic/non-carcinogenic chemical.

Secondary contaminants may cause cosmetic effects (such as skin or tooth discoloration) or aesthetic effects (such as taste, odor, or color) in drinking water. The numerical secondary standards are designed to control these effects to a level desirable to consumers.

Table 2.3 and Table 2.4 list contaminants regulated by federal primary and secondary drinking water standards.

Table 2.3 - Primary Drinking Water Standards

Microorganisms

Contaminant	MCLG (mg/L)	MCL or TT (mg/L)
Cryptosporidium	0	TT
Giardia Lamblia	0	TT
Heterotrophic plate count	n/a	TT
Legionella	0	TT
Total Coliform (including fecal coliform and E. coli)	0	5%
Turbidity	n/a	TT
Viruses (enteric)	0	TT

MCLG: Maximum contaminant level goal
MCL: Maximum contaminant level
TT: Treatment technology

Disinfection Byproducts

Contaminant	MCLG (mg/L)	MCL or TT (mg/L)
Bromate	0	0.01
Chlorite	0.8	1
Haloacetic acids (HAA5)	n/a	0.06
Total Trihalomethanes (TTHMs)	n/a	0.08

Disinfectants

Contaminant	MRDLG (mg/L)	MRDL (mg/L)
Chloramines (as Cl_2)	4.0	4.0
Chlorine (as Cl_2)	4.0	4.0
Chlorine dioxide (as ClO_2)	0.8	0.8

MRDL: Maximum Residual Disinfectant Level
MRDLG: Maximum Residual Disinfectant Level Goal

Inorganic Chemicals

Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
Antimony	07440-36-0	0.006	0.006
Arsenic	07440-38-2	0	0.01 as of 01/23/06
Asbestos (fiber >10 micrometers)	01332-21-5	7 million fibers per liter	7 MFL
Barium	07440-39-3	2	2
Beryllium	07440-41-7	0.004	0.004
Cadmium	07440-43-9	0.005	0.005
Chromium (total)	07440-47-3	0.1	0.1
Copper	07440-50-8	1.3	TT; Action Level=1.3
Cyanide (as free cyanide)	00057-12-5	0.2	0.2
Fluoride	16984-48-8	4	4

Inorganic Chemicals

Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
Lead	07439-92-1	0	TT; Action Level=0.015
Mercury (inorganic)	07439-97-6	0.002	0.002
Nitrate (measured as Nitrogen)		10	10
Nitrite (measured as Nitrogen)		1	1
Selenium	07782-49-2	0.05	0.05
Thallium	07440-28-0	0.0005	0.002

Organic Chemicals

Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
Acrylamide	00079-06-1	0	TT
Alachlor	15972-60-8	0	0.002
Atrazine	01912-24-9	0.003	0.003
Benzene	00071-43-2	0	0.005
Benzo(a)pyrene (PAHs)	00050-32-8	0	0.0002
Carbofuran	01563-66-2	0.04	0.04
Carbon tetrachloride	00056-23-5	0	0.005
Chlordane	00057-74-9	0	0.002
Chlorobenzene	00108-907	0.1	0.1
2,4-Dichloro-phenoxyacetic acid (2,4-D)	00094-75-7	0.07	0.07
Dalapon	00075-99-0	0.2	0.2
1,2-Dibromo-3-chloropropane (DBCP)	00096-12-8	0	0.0002
o-Dichlorobenzene	00095-50-1	0.6	0.6
p-Dichlorobenzene	00106-46-7	0.075	0.075
1,2-Dichloroethane	00107-06-2	0	0.005
1,1-Dichloroethylene	00075-35-4	0.007	0.007
cis-1,2-Dichloroethylene	00156-59-2	0.07	0.07
trans-1,2-Dichloroethylene	00156-60-5	0.1	0.1
Dichloromethane	00074-87-3	0	0.005
1,2-Dichloropropane	00078-87-5	0	0.005
Di(2-ethylhexyl) adipate	00103-23-1	0.4	0.4
Di(2-ethylhexyl) phthalate	00117-81-7	0	0.006
Dinoseb	00088-85-7	0.007	0.007
Dioxin (2,3,7,8-TCDD)	01746-01-6	0	0.00000003
Diquat		0.02	0.02
Endothall	00145-73-3	0.1	0.1
Endrin	00072-20-8	0.002	0.002
Epichlorohydrin		0	TT
Ethylbenzene	00100-41-4	0.7	0.7
Ethylene dibromide	00106-93-4	0	0.00005
Glyphosate	01071-83-6	0.7	0.7
Heptachlor	00076-44-8	0	0.0004

Organic Chemicals

Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
Heptachlor epoxide	01024-57-3	0	0.0002
Hexachlorobenzene	00118-74-1	0	0.001
Hexachlorocyclopentadiene	00077-47-4	0.05	0.05
Lindane	00058-89-9	0.0002	0.0002
Methoxychlor	00072-43-5	0.04	0.04
Oxamyl (Vydate)	23135-22-0	0.2	0.2
Polychlorinated biphenyls (PCBs)		0	0.0005
Pentachlorophenol	00087-86-5	0	0.001
Picloram	01918-02-1	0.5	0.5
Simazine	00122-34-9	0.004	0.004
Styrene	00100-42-5	0.1	0.1
Tetrachloroethylene	00127-18-4	0	0.005
Toluene	00108-88-3	1	1
Toxaphene	08001-35-2	0	0.003
2,4,5-TP (Silvex)	00093-72-1	0.05	0.05
1,2,4-Trichlorobenzene	00120-82-1	0.07	0.07
1,1,1-Trichloroethane	00071-55-6	0.2	0.2
1,1,2-Trichloroethane	00079-00-5	0.003	0.005
Trichloroethylene	00079-01-6	0	0.005
Vinyl chloride	00075-01-4	0	0.002
Xylenes (total)		10	10

Radionuclides

Contaminant	MCLG (mg/L)	MCL or TT (mg/L)
Alpha particles	none ---------- zero	15 picocuries per Liter (pCi/L)
Beta particles and photon emitters	none ---------- zero	4 millirems per year
Radium 226 and Radium 228 (combined)	none ---------- zero	5 pCi/L
Uranium	zero	30 ug/L

Table 2.4 - Secondary Drinking Water Standards

Contaminant	CAS number	Standard
Aluminum	07439-90-5	0.05 to 0.2 mg/L
Chloride		250 mg/L
Color		15 (color units)
Copper	07440-50-8	1.0 mg/L
Corrosivity		Non-corrosive
Fluoride	16984-48-8	2.0 mg/L
Foaming Agents (surfactants)		0.5 mg/L
Iron	07439-89-6	0.3 mg/L
Manganese	07439-96-5	0.05 mg/L
Odor		3 threshold odor number
pH		6.5-8.5
Silver	07440-22-4	0.10 mg/L
Sulfate	14808-79-8	250 mg/L
Total Dissolved Solids		500 mg/L
Zinc	07440-66-6	5 mg/L

New York State is a primacy state and has assumed responsibility for the implementation of the drinking water protection program.

2.4.3.2 New York State

Authorization to use water for a public drinking water system is subject to Article 15, Title 15 of the ECL administered by the Department, while the design and operation of a public drinking water system and quality of drinking water is regulated under the State Sanitary Code 10 NYCRR, Subpart 5-1 administered by NYSDOH.[27]

Anyone planning to operate or operating a public water supply system must obtain a Water Supply Permit from the Department before undertaking any of the regulated activities.

Contact with the Department and submission of a Water Supply Permit application will automatically involve NYSDOH, which has a regulatory role in water quality and other sanitary aspects of a project relating to human health. Through the State Sanitary Code (Chapter 1 of 10 NYCRR), NYSDOH oversees the suitability of water for human consumption. Section 5-1.30 of

[27] 6 NYCRR 601 – http://www.dec.ny.gov/regs/4445.html.

10 NYCRR[28] prescribes the required minimum treatment for public water systems, which depends on the source water type and quality. To assure the safety of drinking water in New York, NYSDOH, in cooperation with its partners, the county health departments, regulates the operation, design and quality of public water supplies; assures water sources are adequately protected, and sets standards for constructing individual water supplies.

NYSDOH standards, established in regulations found at Section 5-1.51 of 10 NYCRR and accompanying Tables in Section 1.52, meet or exceed national drinking water standards. These standards address national primary standards, secondary standards and other contaminants, including those not listed in federal standards such as principal organic contaminants with specific chemical compound classification and unspecified organic contaminants.

2.4.4 Public Water Systems

Public water systems in New York range in size from that of NYC, the largest engineered water system in the nation, serving more than nine million people, to those run by municipal governments or privately-owned water supply companies serving municipalities of varying size and type, schools with their own water supply, and small retail outlets in rural areas serving customers water from their own wells. Privately owned, residential wells supplying water to individual households do not require a water supply permit. In total, there are nearly 10,000 public water systems in New York State. A majority of the systems (approximately 8,460) rely on groundwater aquifers, although a majority of the State's population is served by surface water sources. Public water systems include community water systems (CWS) and non-community water systems (NCWS). NCWSs include non-transient non-community (NTNC) and transient non-community (TNC) water systems. NYSDOH regulations contain the definitions listed in Table 2.5.

[28] 10 NYCRR 5-1.30 – http://www.health.state.ny.us/nysdoh/phforum/nycrr10.htm.

Table 2.5 - Public Water System Definition[29]

Public water system means a community, non-community or non-transient non-community water system which provides water to the public for human consumption through pipes or other constructed conveyances, if such system has at least five service connections or regularly serves an average of at least 25 individuals daily at least 60 days out of the year. Such term includes: a. collection, treatment, storage and distribution facilities under control of the supplier of water of such system and used with such system; and b. collection or pretreatment storage facilities not under such control which are used with such system. **Community water system (CWS)** means a public water system which serves at least five service connections used by year-round residents or regularly serves at least 25 year-round residents. **Noncommunity water system (NCWS)** means a public water system that is not a community water system. **Non-transient noncommunity water system (NTNC)** means a public water system that is not a community water system but is a subset of a noncommunity water system that regularly serves at least 25 of the same people, four hours or more per day, for four or more days per week, for 26 or more weeks per year. **Transient noncommunity water system (TNC)** means a noncommunity water system that does not regularly serve at least 25 of the same people over six months per year.

2.4.4.1 Primary and Principal Aquifers

About one quarter of New Yorkers rely on groundwater as a source of potable water. In order to enhance regulatory protection in areas where groundwater resources are most productive and most vulnerable, the NYSDOH, in 1981, identified 18 Primary Water Supply Aquifers (also referred to simply as Primary Aquifers) across the State. These are defined in the Division of Water (DOW) Technical and Operational Guidance Series (TOGS) 2.1.3[30] as "highly productive aquifers presently utilized as sources of water supply by major municipal water supply systems."

Many Principal Aquifers have also been identified and are defined in the DOW TOGS as "highly productive, but which are not intensively used as sources of water supply by major municipal systems at the present time." Principal Aquifers are those known to be highly productive aquifers or where the geology suggests abundant potential supply, but are not presently being heavily used for public water supply. The 21 Primary and the many Principal Aquifers greater than one square mile in area within New York State (excluding Long Island) are shown on

[29] 10 NYCRR, Part 5, Subpart 5-1 Public Water Systems (Current as of: October 1, 2007); SUBPART 5-1; PUBLIC WATER SYSTEMS; 5-1.1 Definitions. (Effective Date: May 26, 2004).

[30] http://www.dec.ny.gov/docs/water_pdf/togs213.pdf.

Map No.	Aquifer Name	Number of Wells Within Mapped Aquifer Boundary		
		Gas Wells	Oil Wells	Other Wells*
1	Baldwinsville	37	0	3
2	Batavia	0	0	5
3	Corning	5	0	4
4	Cortland-Homer-Preble	0	0	2
5	Elmira-Horseheads-Big Flats	6	0	16
6	Endicott-Johnson City	0	0	3
7	Fulton	4	0	2
8	Jamestown	82	11	14
9	Lower Cohocton	4	0	24
10	Olean	7	310	81
11	Owego	0	0	2
12	Salamanca	14	2	6
13	Upper Cohocton	0	0	3
14	Waverly	0	0	1
	Principal Aquifer	1,664	749	1,344
	Total	*1,823*	*1,072*	*1,510*

Notes:

* - Other wells include storage, solution brine, dry hole, injection, stratigraphic, geothermal, and not listed well types.

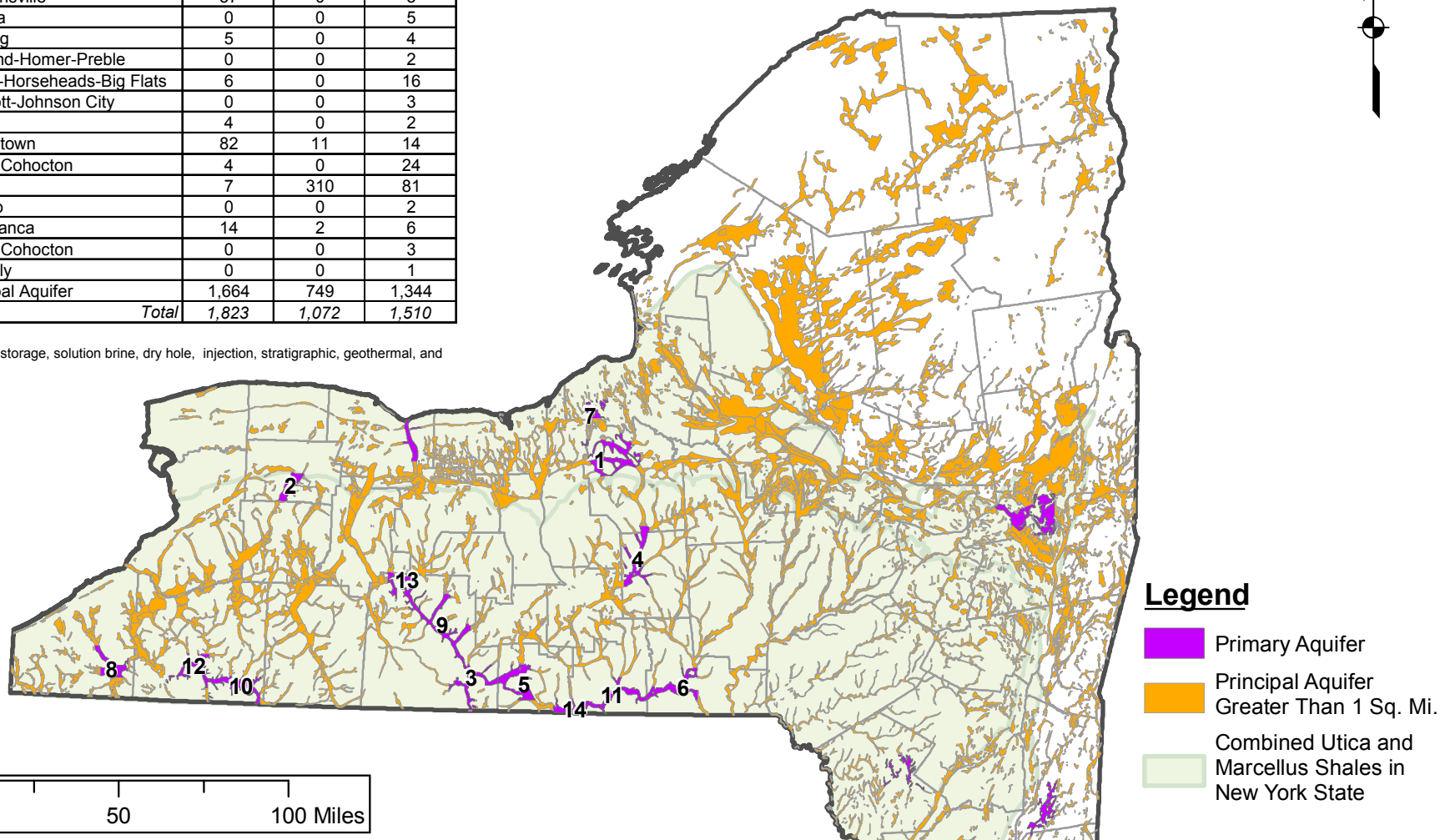

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FIGURE 2.1

REGULATED OIL, GAS, & OTHER WELLS IN PRIMARY AND PRINCIPAL AQUIFERS IN NEW YORK STATE

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

Source:
- "New York State Aquifers" by NYS Department of Health, Bureau of Public Water Supply Protection (April 2001) on http://nysgis.state.ny.us/gis9/nyaquifers.zip.
- Well information from (February 2009) http://www.dec.ny.gov/energy/1603.html

Figure 2.1. The remaining portion of the State is underlain by smaller aquifers or low-yielding groundwater sources that typically are suitable only for small community and non-community public water systems or individual household supplies.[31]

2.4.4.2 Public Water Supply Wells

NYSDOH estimates that over two million New Yorkers outside of Long Island are served by public groundwater supplies.[32] Most public water systems with groundwater sources pump and treat groundwater from wells. Public groundwater supply wells are governed by Subpart 5-1 of the State Sanitary Code under 10 NYCRR.[33]

2.4.5 Private Water Wells and Domestic-Supply Springs

There are potentially tens to hundreds of thousands of private water supply wells in the State. To ensure that private water wells provide adequate quantities of water fit for consumption and intended uses, they need to be located and constructed to maintain long-term water yield and reduce the risk of contamination. Improperly constructed water wells can allow for easy transport of contaminants to the well and pose a significant health risk to users. New, replacement or renovated private wells are required to be in compliance with the New York State Residential Code, NYSDOH Appendix 5-B "Standards for Water Wells,"[34] installed by a certified Department-registered water well contractor and have groundwater as the water source. However, many private water wells installed before these requirements took effect are still in use. The 1992 GEIS describes how improperly constructed private water wells are susceptible to pollution from many sources, and proposes a 150-foot setback to protect vulnerable private wells.[35]

NYSDOH includes springs – along with well points, dug wells and shore wells – as susceptible sources that are vulnerable to contamination from pathogens, spills and the effects of drought.[36]

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[31] Alpha, 2009, p. 3-2.

[32] http://www.health.state.ny.us/environmental/water/drinking/facts_figures.htm.

[33] http://www.health.state.ny.us/environmental/water/drinking/part5/subpart5.htm.

[34] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm.

[35] NYSDEC, 1992, GEIS, p. 8-22.

[36] http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs5_susceptible_water_sources.htm.

Use of these sources for drinking water is discouraged and should be considered only as a last resort with proper protective measures. With respect to springs, NYSDOH specifically states:

> Springs occur where an aquifer discharges naturally at or near the ground surface, and are broadly classified as either rock or earth springs. It is often difficult to determine the true source of a spring (that is, whether it truly has the natural protection against contamination that a groundwater aquifer typically has.) Even if the source is a good aquifer, it is difficult to develop a collection device (e.g., "spring box") that reliably protects against entry of contaminants under all weather conditions. (The term "spring box" varies, and, depending on its construction, would be equivalent to, and treated the same, as either a spring, well point or shore well.) Increased yield and turbidity during rain events are indications of the source being under the direct influence of surface water.[37]

Because of their vulnerability, and because in addition to their use as drinking water supplies they also supply water to wetlands, streams and ponds, the 1992 GEIS proposes a 150-foot setback.[38]

For oil and gas regulatory purposes, potable fresh water is defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS[39] and salt water is defined as containing more than 250 ppm sodium chloride or 1,000 ppm TDS.[40] Groundwater from sources below approximately 850 feet in New York typically is too saline for use as a potable water supply; however, there are isolated wells deeper than 850 feet that produce potable water and wells less than 850 feet that produce salt water. A depth of 850 feet to the base of potable water is commonly used as a practical generalization for the maximum depth of potable water; however, a variety of conditions affect water quality, and the maximum depth of potable water in an area should be determined based on the best available data.[41]

2.4.6 History of Drilling and Hydraulic Fracturing in Water Supply Areas

A tabulated summary of the regulated oil, gas, and other wells located within the boundaries of the Primary and Principal Aquifers in the State is provided on Figure 2.1. There are 482 oil and gas wells located within the boundaries of 14 Primary Aquifers and 2,413 oil and gas wells

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[37] NYSDOH - http://www.health.ny.gov/environmental/water/drinking/part5/append5b/docs/fs5_susceptible_water_sources.pdf.

[38] NYSDEC, 1992, GEIS, p. 8-16.

[39] 6 NYCRR Part 550.3(ai).

[40] 6 NYCRR Part 550.3(at).

[41] Alpha, 2009, p. 3-3.

located within the boundaries of Principal Aquifers. Another 1,510 storage, solution brine, injection, stratigraphic, geothermal, and other deep wells are located within the boundaries of the mapped aquifers. The remaining regulated oil and gas wells likely penetrate a horizon of potable freshwater that can be used by residents or communities as a drinking water source. These freshwater horizons include unconsolidated deposits and bedrock units.[42]

Chapter 4, on Geology, includes a generalized cross-section (Figure 4.3) across the Southern Tier of New York State which illustrates the depth and thickness of rock formations including the prospective shale formations.

No documented instances of groundwater contamination from previous horizontal drilling or hydraulic fracturing projects in New York are recorded in the Department's well files or records of complaint investigations. No documented incidents of groundwater contamination in public water supply systems could be recalled by the NYSDOH central office and Rochester district office (NYSDOH, 2009a; NYSDOH, 2009b). References have been made to some reports of private well contamination in Chautauqua County in the 1980s that may be attributed to oil and gas drilling (Chautauqua County Department of Health, 2009; NYSDOH, 2009a; NYSDOH, 2009b; Sierra Club, undated). The reported Chautauqua County incidents, the majority of which occurred in the 1980s and which pre-date the current casing and cementing practices and fresh water aquifer supplementary permit conditions, could not be substantiated because pre-drilling water quality testing was not conducted, improper tests were run which yielded inconclusive results and/or the incidents of alleged well contamination were not officially confirmed.[43]

An operator caused turbidity (February 2007) in nearby water wells when it continued to pump compressed air for many hours through the drill string in an attempt to free a stuck drill bit at a well in the Town of Brookfield, Madison County. The compressed air migrated through natural fractures in the shallow bedrock because the well had not yet been drilled to the permitted surface casing seat depth. This non-routine incident was reported to the Department and staff were dispatched to investigate the problem. The Department shut down drilling operations and ordered the well plugged when it became apparent that continued drilling at the wellsite would cause

[42] Alpha, 2009, p. 3-3.

[43] Alpha, 2009, p. 3-3.

turbidity to increase above what had already been experienced. The operator immediately provided drinking water to the affected residents and subsequently installed water treatment systems in several residences. Over a period of several months the turbidity abated and water wells returned to normal. Operators that use standard drilling practices and employ good oversight in compliance with their permits would not typically cause the excessive turbidity event seen at the Brookfield wells. The Department has no records of similar turbidity caused by well drilling as occurred at this Madison County well. Geoffrey Snyder, Director Environmental Health Madison County Health Department, stated in a May 2009 email correspondence regarding the Brookfield well accident that, "Overall we find things have pretty much been resolved and the water quality back to normal if not better than pre-incident conditions."

2.4.7 Regulated Drainage Basins

New York State is divided into 17 watersheds, or drainage basins, which are the basis for various management, monitoring, and assessment activities.[44] A watershed is an area of land that drains into a body of water, such as a river, lake, reservoir, estuary, sea or ocean. The watershed includes the network of rivers, streams and lakes that convey the water and the land surfaces from which water runs off into those water bodies. Since all of New York State's land area is incorporated into watersheds, all oil and gas drilling that has occurred since 1821 has occurred within watersheds, specifically, in 13 of the State's 17 watersheds. Watersheds are separated from adjacent watersheds by high points, such as mountains, hills and ridges. Groundwater flow within watersheds may not be controlled by the same topographic features as surface water flow.

The river basins described below are subject to additional jurisdiction by existing regulatory bodies with respect to certain specific activities related to high-volume hydraulic fracturing.

The delineations of the Susquehanna and Delaware River Basins in New York are shown on Figure 2.2.

2.4.7.1 Delaware River Basin

Including Delaware Bay, the Delaware River Basin comprises 13,539 square miles in four states (New York, Pennsylvania, Delaware and New Jersey). Approximately 18.5 % of the surface area

[44] See map at http://www.dec.ny.gov/lands/26561.html.

of the basin, or 2,362 square miles, lies within portions of Broome, Chenango, Delaware, Schoharie, Greene, Ulster, Sullivan and Orange Counties in New York. This acreage overlaps with NYC's West of Hudson Watershed; the Basin supplies about half of NYC's drinking water and 100% of Philadelphia's supply.

The DRBC was established by a compact among the federal government, New York, New Jersey, Pennsylvania and Delaware to coordinate water resource management activities and the review of projects affecting water resources in the basin. New York is represented on the DRBC by a designee of New York State's Governor, and the Department has the opportunity to provide input on projects requiring DRBC action.

DRBC has identified its areas of concern with respect to natural gas drilling as reduction of flow in streams or aquifers, discharge or release of pollutants into ground water or surface water, and treatment and disposal of hydraulic fracturing fluid. DRBC staff will also review drill site characteristics, fracturing fluid composition and disposal strategy prior to recommending approval of shale gas development projects in the Delaware River Basin.[45]

2.4.7.2 Susquehanna River Basin

The Susquehanna River Basin comprises 27,510 square miles in three states (New York, Pennsylvania and Maryland) and drains into the Chesapeake Bay. Approximately 24 % of the basin, or 6,602 square miles, lies within portions of Allegany, Livingston, Steuben, Yates, Ontario, Schuyler, Chemung, Tompkins, Tioga, Cortland, Onondaga, Madison, Chenango, Broome, Delaware, Schoharie, Otsego, Herkimer and Oneida Counties in New York.

[45] http://www.state.nj.us/drbc/naturalgas.htm

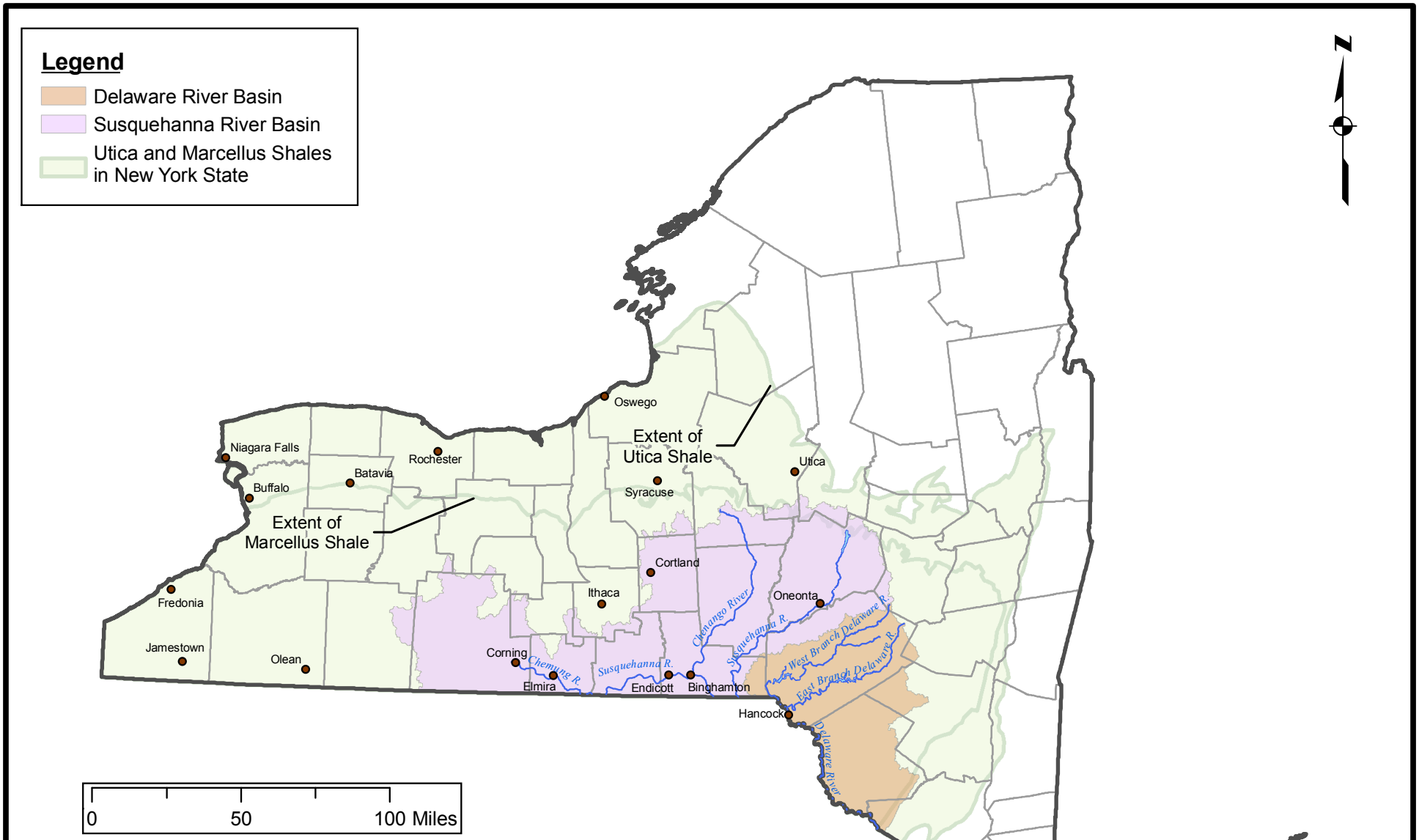

FIGURE 2.2

MAJOR TRIBUTARIES IN THE SUSQUEHANNA & DELAWARE RIVER BASINS IN NEW YORK STATE

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

ALPHA GEOSCIENCE

Alpha Project No. 09104

Sources:
- Delaware River Basin Commission Geographic Information System http://www.state.nj.us/drbc/gis.htm.
- Susquehanna River Basin Commision Map and Data Atlas http://www.srbc.net/atlas/whatgis.asp

The SRBC was established by a compact among the federal government, New York, Pennsylvania and Maryland to coordinate water resource management activities and review of projects affecting water resources in the Basin. New York is represented on the SRBC by a designee of the Department's Commissioner, and the Department has the opportunity to provide input on projects requiring SRBC action.

The Susquehanna River is the largest tributary to the Chesapeake Bay, with average annual flow to the Bay of over 20 billion gallons per day (gpd). Based upon existing consumptive use approvals plus estimates of other uses below the regulatory threshold requiring approval, SRBC estimates current maximum use potential in the Basin to be 882.5 million gpd. Projected maximum consumptive use in the Basin for gas drilling, calculated by SRBC based on twice the drilling rate in the Barnett Shale play in Texas, is about 28 million gpd as an annual average.[46]

2.4.7.3 Great Lakes-St. Lawrence River Basin

In New York, the Great Lakes-St. Lawrence River Basin is the watershed of the Great Lakes and St. Lawrence River, upstream from Trois Rivieres, Quebec, and includes all or parts of 34 counties, including the Lake Champlain and Finger Lakes sub-watersheds. Approximately 80 percent of New York's fresh surface water, over 700 miles of shoreline, and almost 50% of New York's lands are contained in the drainage basins of Lake Ontario, Lake Erie, and the St. Lawrence River. Jurisdictional authorities in the Great Lakes-St. Lawrence River Basin, in addition to the Department, include the Great Lakes Commission, the Great Lakes Fishery Commission, the International Joint Commission, the Great Lakes-St. Lawrence River Water Resources Compact Council, and the Great Lakes-St. Lawrence Sustainable Water Resources Regional Body.

2.4.8 Water Resources Replenishment[47]

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

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[46] http://www.srbc.net/programs/projreviewmarcellustier3.htm.

[47] Alpha, 2009, p. 3-26.

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

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

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

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

Floods may occur from short or long periods of above-normal precipitation and rapid snow melt. Flooding results in increased flow in streams and rivers and may increase levels in lakes and reservoirs. Periods of above-normal precipitation that may cause flooding also may result in

increased groundwater levels and greater availability of groundwater. The duration of floods typically is relatively short compared to periods of drought.

The SRBC and DRBC have established evaluation processes and mitigation measures to ensure adequate replenishment of water resources. The evaluation processes for proposed withdrawals address recharge potential and low-flow conditions. Examples of the mitigation measures utilized by the SRBC include:

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

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

2.4.9 Floodplains

Floodplains are low-lying lands next to rivers and streams. When left in a natural state, floodplain systems store and dissipate floods without adverse impacts on humans, buildings, roads or other infrastructure. Floodplains can be viewed as a type of natural infrastructure that can provide a safety zone between people and the damaging waters of a flood. Changes to the landscape outside of floodplain boundaries, like urbanization and other increases in the area of impervious surfaces in a watershed, may increase the size of floodplains. Floodplain information is found on Flood Insurance Rate Maps (FIRMs) produced by the Federal Emergency Management Agency (FEMA). These maps are organized on either a county, town, city or

village basis and are available through the FEMA Map Service Center.[48] They may also be viewed at local government facilities, the Department, and county and regional planning offices.

A floodplain development permit issued by a local government (town, city or village) must be obtained before commencing any floodplain development activity. This permit must comply with a local floodplain development law (often named Flood Damage Prevention Laws), designed to ensure that development will not incur flood damages or cause additional off-site flood damages. These local laws, which qualify communities for participation in the National Flood Insurance Program (NFIP), require that any development in mapped, flood hazard areas be built to certain standards, identified in the NFIP regulations (44 CFR 60.3) and the Building Code of New York State and the Residential Code of New York State. Floodplain development is defined to mean any man-made change to improved or unimproved real estate, including but not limited to buildings or other structures (including gas and liquid storage tanks), mining, dredging, filling, paving, excavation or drilling operations, or storage of equipment or materials. Virtually all communities in New York with identified flood hazard areas participate in the NFIP.

The area that would be inundated by a 100-year flood (also thought of as an area that has a one percent or greater chance of experiencing a flood in any single year) is designated as a Special Flood Hazard Area. The 100-year flood is also known as the *base flood*, and the elevation that the base flood reaches is known as the base flood elevation (BFE). The BFE is the basic standard for floodplain development, used to determine the required elevation of the lowest floor of any new or substantially improved structure. For streams where detailed hydraulic studies have identified the BFE, the 100-year floodplain has been divided into two zones, the floodway and the floodway fringe. The floodway is that area that must be kept open to convey flood waters downstream. The floodway fringe is that area that can be developed in accordance with FEMA standards as adopted in local law. The floodway is shown either on the community's FIRM or on a separate “Flood Boundary and Floodway” map or maps published before about 1988. Flood Damage Prevention Laws differentiate between more hazardous floodways and other areas inundated by flood water. In particular for floodways, no encroachment can be permitted unless

[48] http://msc.fema.gov.

there is an engineering analysis that proves that the proposed development does not increase the BFE by any measurable amount at any location.

Each participating community in the State has a designated floodplain administrator. This is usually the building inspector or code enforcement official. If development is being considered for a flood hazard area, then the local floodplain administrator reviews the development to ensure that construction standards have been met before issuing a floodplain development permit.

2.4.9.1 Analysis of Recent Flood Events[49]

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

The increased frequency and magnitude of flooding has raised a concern for unconventional gas drilling in the floodplains of these rivers and tributaries, and the recent flooding has identified concerns regarding the reliability of the existing FEMA FIRMs that depict areas that are prone to flooding with a defined probability or recurrence interval. The concern focused on the Susquehanna and Delaware Rivers and associated tributaries in Steuben, Chemung, Tioga, Broome, Chenango, Otsego, Delaware and Sullivan Counties, New York.

2.4.9.2 Flood Zone Mapping[50]

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

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[49] Alpha, 2009, p. 3-30.

[50] Alpha, 2009, p. 3-30.

Appendix 1 Alpha's Table 3.4 – FIRM Maps summarizes the availability of FIRMs for New York State as of July 23, 2009 (FEMA, 2009a). FIRMs are available for all communities in Broome, Delaware, and Sullivan Counties. The effective date of each FIRM is included in Appendix 1. As shown, many of the communities in New York use FIRMs with effective dates prior to the recent flood events. Natural and anthropogenic changes in stream morphology (e.g., channelization) and land use/land cover (e.g., deforestation due to fires or development) can affect the frequency and extent of flooding. For these reasons, FIRMs are updated periodically to reflect current information. Updating FIRMs and incorporation of recent flood data can take two to three years (FEMA, 2009b).

While the FIRMs are legal documents that depict flood-prone areas, the most up-to-date information on extent of recent flooding is most likely found at local or county-wide planning or emergency response departments (DRBC, 2009). Many of the areas within the Delaware and Susquehanna River Basins that were affected by the recent flooding of 2004 and 2006 lie outside the flood zones noted on the FIRMs (SRBC, 2009; DRBC, 2009; Delaware County 2009). Flood damage that occurs outside the flood zones often is related to inadequate maintenance or sizing of storm drain systems and is unrelated to streams. Mapping the areas affected by recent flooding in the Susquehanna River Basin currently is underway and is scheduled to be published in late 2012 (SRBC, 2011). Updated FIRMs are being prepared for communities in Delaware County affected by recent flooding and are expected to be released in late 2012 (Delaware County, 2011).

According to the DOW, preliminary county-wide FIRMs have been completed and adopted by Sullivan County. County-wide FIRMs for Broome and Delaware Counties are scheduled to be completed in late 2012.

2.4.9.3 Seasonal Analysis[51]

The historic and recent flooding events do not show a seasonal trend. Flooding in Delaware County, which resulted in Presidential declarations of disaster and emergency between 1996 and 2006, occurred during the following months: January 1996, November 1996, July 1998, August 2003, October 2004, August 2004 and April 2005 (Tetra Tech, 2005). The Delaware River and many of its tributaries in Delaware and Sullivan Counties experienced major flooding that caused

[51] Alpha, 2009, p. 3-31.

extensive damage from September 2004 to June 2006 (Schopp and Firda, 2008). These data show that flooding is not limited to any particular season and may occur at any time during the year.

2.4.10 Freshwater Wetlands

Freshwater wetlands are lands and submerged lands, commonly called marshes, swamps, sloughs, bogs, and flats, supporting aquatic or semi-aquatic vegetation. These ecological areas are valuable resources, necessary for flood control, surface and groundwater protection, wildlife habitat, open space, and water resources. Freshwater wetlands also provide opportunities for recreation, education and research, and aesthetic appreciation. Adjacent areas may share some of these values and, in addition, provide a valuable buffer for the wetlands.

The Department has classified regulated freshwater wetlands according to their respective functions, values and benefits. Wetlands may be Class I, II, III or IV. Class I wetlands are the most valuable and are subject to the most stringent standards.

The Freshwater Wetlands Act (FWA), Article 24 of the ECL, provides the Department and the Adirondack Park Agency (APA) with the authority to regulate freshwater wetlands in the State. The NYS Legislature passed the Freshwater Wetlands Act in 1975 in response to uncontrolled losses of wetlands and problems resulting from those losses, such as increased flooding. The FWA protects wetlands larger than 12.4 acres (5 hectares) in size, and certain smaller wetlands of unusual local importance. In the Adirondack Park, the APA regulates wetlands, including wetlands above one acre in size, or smaller wetlands if they have free interchange of flow with any surface water. The law requires the Department and APA to map those wetlands that are protected by the FWA. In addition, the law requires the Department and APA to classify wetlands. Inside the Adirondack Park, wetlands are classified according to their vegetation cover type. Outside the Park, the Department classifies wetlands according to 6 NYCRR Part 664, Wetlands Mapping and Classification.[52] Around every regulated wetland is a regulated adjacent area of 100 feet, which serves as a buffer area for the wetland.

FWA's main provisions seek to regulate those uses that would have an adverse impact on wetlands, such as filling or draining. Other activities are specifically exempt from regulation,

[52] 6 NYCRR 664 - http://www.dec.ny.gov/regs/4612.html.

such as cutting firewood, continuing ongoing activities, certain agricultural activities, and most recreational activities like hunting and fishing. In order to obtain an FWA permit, a project must meet the permit standards in 6 NYCRR Part 663, Freshwater Wetlands Permit Requirement Regulations.[53] Intended to prevent despoliation and destruction of freshwater wetlands, these regulations were designed to:

- preserve, protect, and enhance the present and potential values of wetlands;
- protect the public health and welfare; and
- be consistent with the reasonable economic and social development of the State.

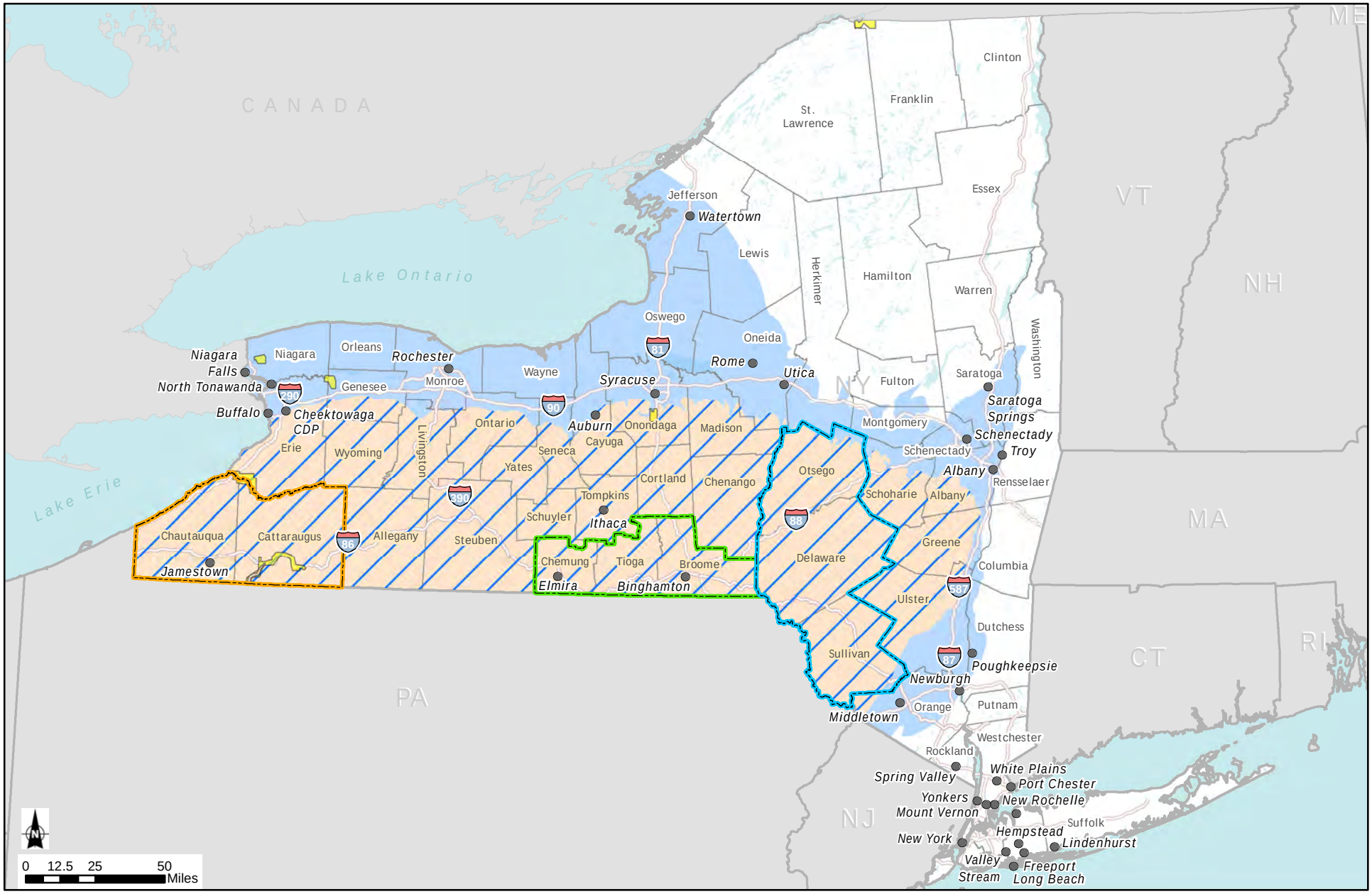
2.4.11 Socioeconomic Conditions[54]

The Marcellus and Utica Shales are the most prominent shale formations in New York State. The prospective region for the extraction of natural gas from these formations generally extends from Chautauqua County eastward to Greene, Ulster, and Sullivan Counties, and from the Pennsylvania border north to the approximate location of the east-west portion of the New York State Thruway, between Schenectady and Auburn (Figure 2.3). This region covers all or parts of 30 counties. Fourteen counties are entirely within the area underlain by the Marcellus and Utica Shales, and 16 counties are partially within the area.

Due to the broad extent of the prospective region for the extraction of natural gas from the Marcellus and Utica Shales, the socioeconomic analysis in the SGEIS focuses on representative regional and local areas of New York State where natural gas extraction may occur, and also provides a statewide analysis. The three regions were selected to evaluate differences between areas with a high, moderate and low production potential; areas that have experienced gas development in the past and areas that have not experienced gas development in the past; and differences in land use patterns. The three representative regions and the respective counties within the region are:

[53] 6 NYCRR 663 - http://www.dec.ny.gov/regs/4613.html.

[54] Subsection 2.4.11, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.



Representative Regions
- Region A
- Region B
- Region C

CDP = Census Designated Place

- Place with Year 2010 Population Greater than 25,000
- Major Water Bodies
- County Boundary
- State Boundary
- Tribal Lands Boundary
- Marcellus Shale Extent in New York State
- Utica Shale Extent in New York State
- Extent of Marcellus and Utica Shales in NYS

Figure 2.**3**: Representative Regions within the Marcellus Shale Extent in New York

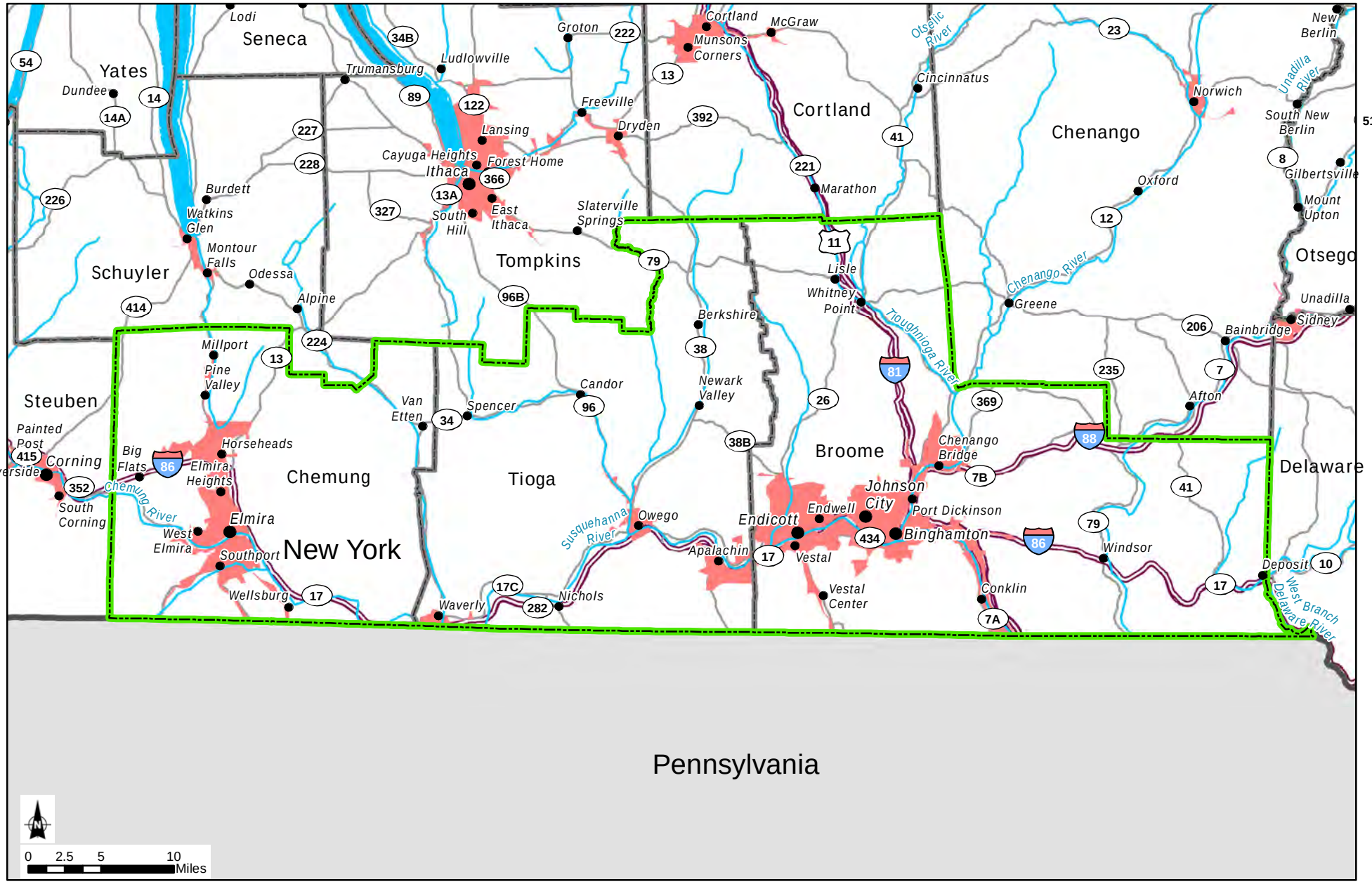
Source: ESRI, 2010; USGS, 2002

- Region A: Broome County, Chemung County, and Tioga County (Figure 2.4a);
- Region B: Delaware County, Otsego County, and Sullivan County (Figure 2.4b); and
- Region C: Cattaraugus County and Chautauqua County (Figure 2.4c);

Region A is defined as a high-potential production area. Wells in Broome, Chemung, and Tioga Counties are expected to yield some of the highest production of shale gas, based on the geology, thermal maturity of the organic matter, and other geochemical factors of the Marcellus and Utica Shale formations. Due to the proximity to active gas drilling in these counties, and neighboring counties in Pennsylvania, the associated infrastructure (pipelines) has already been developed. With the associated infrastructure in place, developers are expected to begin development of wells in this area if development in New York State is approved. Region A encompasses urban/suburban land uses associated with the larger cities of Binghamton and Elmira, as well as rural settings. In addition, conventional natural gas development has occurred in this area.

Region B is defined as an average-potential production area. High-volume hydraulic-fracturing is expected to occur in portions of Delaware, Otsego, and Sullivan Counties, but the production of shale gas is not anticipated to reach the levels expected in Region A. Region B is largely rural and encompasses part of the Catskill Mountains. Development in this region would be limited by the exclusion of drilling from the New York City watershed and state-owned lands (e.g., the Forest Preserve) in the Catskill Mountains. To date, only exploratory natural gas well development has occurred in this region.

Region C is defined as a low-potential production area. Although Chautauqua and Cattaraugus Counties are within the footprints of both the Utica and Marcellus Shales, they are outside of the fairways for both shales; thus, horizontal wells in this region would not be expected to yield enough gas to be economically feasible. However, thousands of vertical gas wells exist in conventional formations, and additional vertical wells would likely be constructed. If the price of gas increases or drilling technology advances, gas production in the Utica or other formations in this region may become more feasible. Region C is largely rural, and conventional natural gas development has been occurring in this area for many years.



Representative Region A
County Boundary
State Boundary
Urban Area
River/Stream
Highway/Major Road
Secondary Road

Figure 2.4a: Representative Region A

Source: ESRI, 2010; USGS, 2002

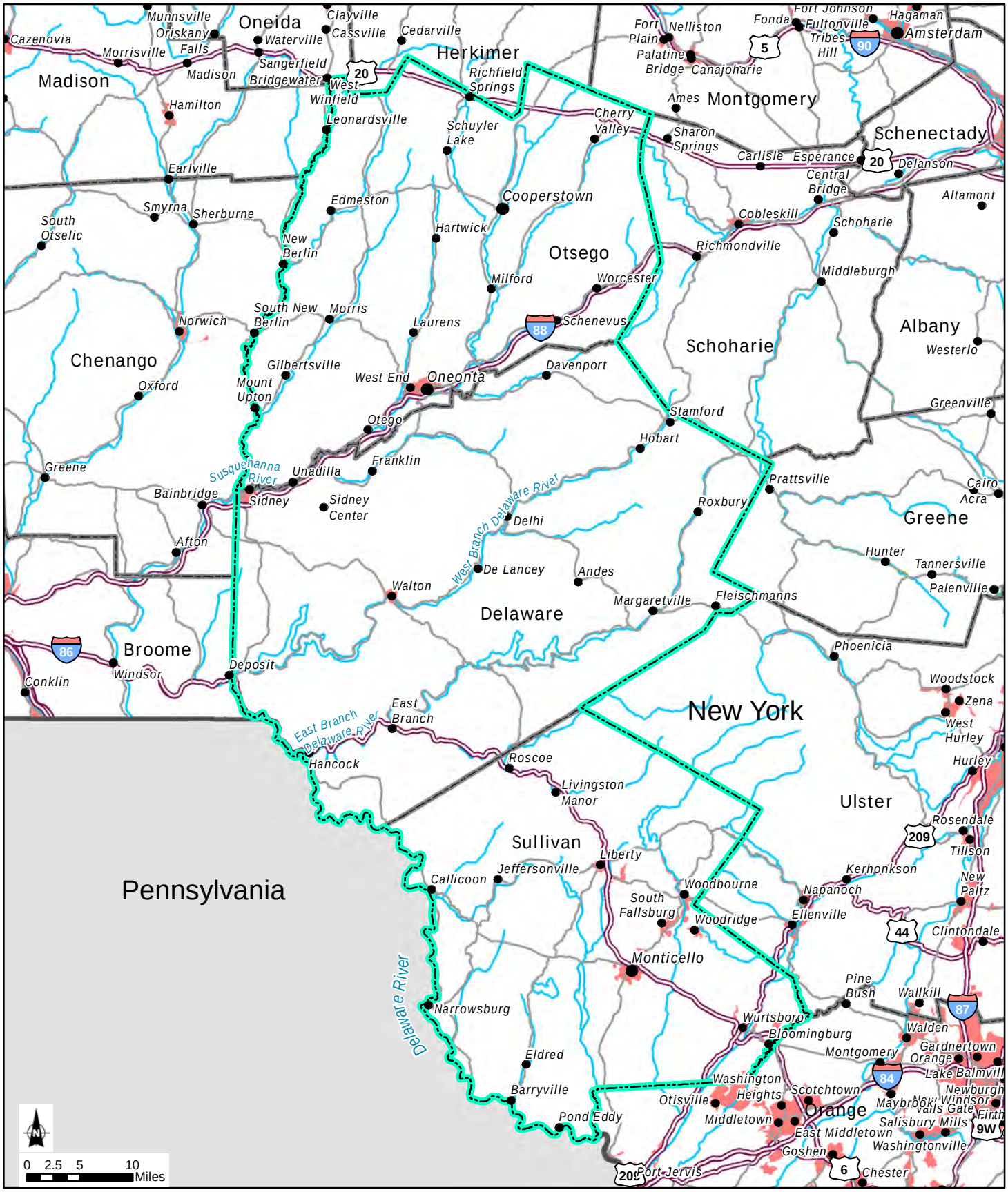
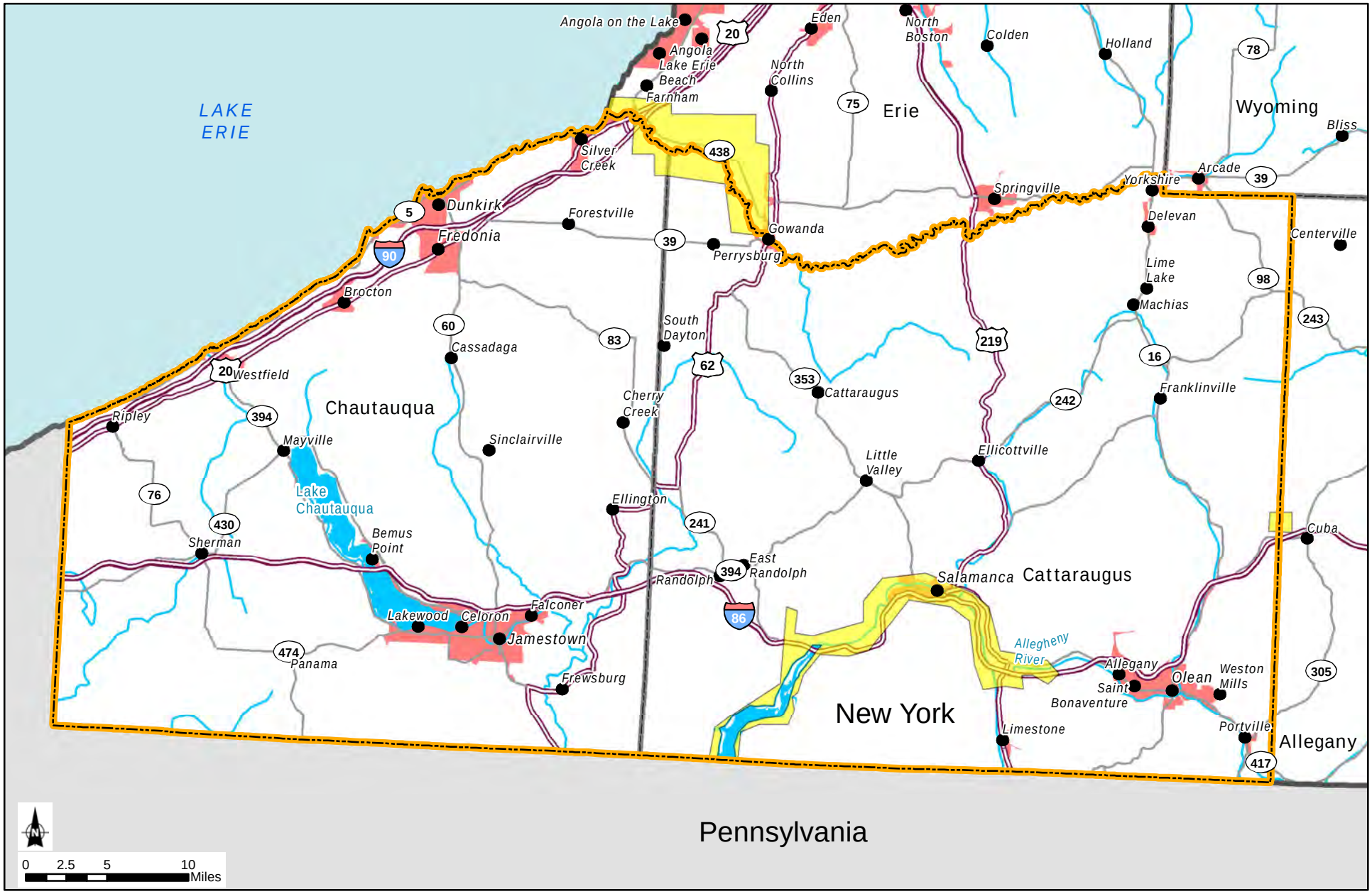


Figure 2.4b: Representative Region B

Source: NESRI, 2010; USGS, 2002



Representative Region C
County Boundary
State Boundary
Urban Area
River/Stream
Highway/Major Road
Secondary Road
Tribal Lands Boundary

Figure 2.4c: Representative Region C

Source: NESRI, 2010; USGS, 2002

While these regions are being analyzed as a way to assess the impacts on representative local communities, actual development would not be limited to these regions, and impacts similar to those described in Section 6 could occur anywhere where high-volume hydraulic-fracturing wells are developed. Therefore, this section also provides the socioeconomic baseline for the state as a whole.

A description of the baseline socioeconomic conditions includes Economy, Employment and Income (Subsection 2.4.11.1); Population (Subsection 2.4.11.2); Housing (Subsection 2.4.11.3); Government Revenues and Expenditures (Subsection 2.4.11.4); and Environmental Justice (EJ) (Subsection 2.4.11.5). Socioeconomic impacts are discussed in Chapter 6, and socioeconomic mitigation measures are discussed in Chapter 7.

2.4.11.1 Economy, Employment, and Income

This subsection provides a discussion of the economy, employment and income for New York State, and the local areas within each of the three representative regions (Region A, B and C), focusing on the agricultural and tourism industries, as well as existing natural gas development.

Natural gas development is expected to benefit other industries as equipment, material, and supplies are purchased by the natural gas industry and workers spend their wages in the local economy. These positive impacts are discussed in more detail in Section 6. However, as agriculture and tourism relate to uses of the land that may be impacted by natural gas development, those industries are discussed in more detail herein, and potential impacts from both a land use and economic perspective are discussed in Chapter 6.

Several data sources were used to describe the baseline economy, employment, and income for New York State and the local areas, including the U.S. Census Bureau (USCB) and the New York State Department of Labor (NYSDOL). Data from the *2010 Census of Population and Housing* were used to identify major employment sectors for the state and the representative regions. Data from the census is self-reported by individuals and is aggregated to provide general information about the labor force from very small to large geographic areas on a cross-sectional or one-time basis.

Detailed data on employment and wages, by industry, was obtained from the NYSDOL's quarterly census of employment and wages (QCEW). The NYSDOL collects employment and wage data for all employers liable for unemployment insurance. These data were used to provide information on wages and for more detailed information on employment in the travel and tourism and oil and gas sectors. All of the labor statistics from the NYSDOL and USCB are based on the North American Industry Classification System, which is the standard system used by government agencies to classify businesses, although the data may be grouped differently for reporting purposes. Data on agricultural workers is taken from the U.S. Census of Agriculture, which is collected every 5 years, and provides information on the value of farm production and agricultural employment in the state and local areas. Although the data referenced within this section were collected by government agencies using different methodologies, all data were used to support an overall portrait of the statewide and local economies.

New York State

Table 2.6 presents total employment by industry within New York State. As shown, New York State has a large and diverse economy. The largest employment sector in the state is educational, health, and social services, accounting for approximately 26.2% of the total employed labor force (USCB 2009a). Other large sectors are professional, scientific, management, administrative, and waste management services (10.8%); and retail trade (10.5%). Several of the largest private employers in New York State include NY Presbyterian Healthcare System (29,000 employees); Walmart (28,000 employees); Citigroup (27,000 employees); IBM Corporation (21,000 employees); and JP Morgan Chase (21,000 employees).

Table 2.6 - New York State: Area Employment by Industry, 2009 (New August 2011)

Sector	Number of Jobs	% of Total
Agriculture, forestry, fishing, hunting, and mining	54,900	0.6
Construction	548,018	6.0
Manufacturing	672,481	7.4
Wholesale trade	266,946	2.9
Retail trade	959,414	10.5
Transportation and warehousing, utilities	482,768	5.3
Information	299,378	3.3
Finance, insurance, real estate, and renting/leasing	789,372	8.7
Professional, scientific, management, administrative, and waste management services	981,317	10.8
Educational, health, and social services	2,385,864	26.2
Arts, entertainment, recreation, accommodation, and food services	764,553	8.4
Other services (except public administration)	449,940	4.9
Public administration	447,645	4.9
Total	9,102,596	

Source: USCB 2009a.

In 2010, New York State had a total gross domestic product (GDP, i.e., the value of the output of goods and services produced by labor and property located in New York State) of approximately $1.16 trillion (USDOC 2010).

Each region of the state contributes to the state's GDP in different ways. New York City is the leading center of banking, finance, and communications in the United States, and thus has a large number of workers employed in these industrial sectors. In contrast, the economies of large portions of western and central New York are based on agriculture. Manufacturing also plays a significant role in the overall economy of New York State; most manufacturing occurs in the upstate regions, predominantly in the cities of Albany, Buffalo, Rochester, and Syracuse.

Table 2.7 provides total and average wages, by industry, as reported by NYSDOL for 2009.

Table 2.7 - New York State: Wages by Industry, 2009 (New August 2011)

Industry	Total Wages ($ millions)	Average Wage
Total, all industries	$481,690.6	$57,794
Agriculture, forestry, fishing, hunting	640.4	$28,275
Mining	265.5	$55,819
Construction	19,336.0	$59,834
Manufacturing	27,098.4	$57,144
Wholesale trade	22,797.7	$69,282
Retail trade	25,130.8	$29,202
Transportation and warehousing	9,302.9	$42,477
Utilities	3,633.7	$92,469
Information	22,124.3	$87,970
Finance and insurance	86,303.4	$173,899
Real estate and renting/leasing	9,360.2	$52,417
Professional and technical services	48,815.9	$87,136
Management of companies and enterprises	15,648.4	$119,804
Administrative and waste services	16,354.4	$40,546
Educational services	13,606.9	$46,772
Health, and social assistance	55,486.7	$44,104
Arts, entertainment, and recreation	6,154.3	$44,246
Accommodation, and food services	12,178.7	$21,369
Other services (except public administration)	10,732.4	$33,602
Public administration	75,828.4	$52,594

Source: NYSDOL 2009a.

The total labor force in New York State in 2010 was approximately 9,630,900 workers. In 2010, the annual average unemployment rate across New York State was 8.6% (Table 2.8). Between 2000 and 2010, the size of the labor force increased by 5.1%, while the unemployment rate nearly doubled.

Table 2.8 - New York State: Labor Force Statistics, 2000 and 2010 (New August 2011)

	2000	2010
Total labor force	9,167,000	9,630,900
Employed workers	8,751,400	8,806,800
Unemployed workers	415,500	824,100
Unemployment rate (%)	4.5	8.6

Source: NYSDOL 2010a.

In 2009, the per capita income for New York State was $30,634, and 13.9% of the population lived below the poverty level (Table 2.9). Over the past decade, per capita income has increased by 31.0%, and the percentage of individuals living below the poverty level has decreased by 0.7%.

Table 2.9 - New York State: Income Statistics, 1999 and 2009 (New August 2011)

	1999	**2009**
Per capita income	$23,389	$30,634
% Below the poverty level[1]	14.6	13.9

Source: USCB 2000a, 2009b.

[1] If the total income for an individual falls below relevant poverty thresholds, updated annually relative to the Consumer Price Index for All Urban Consumers, then the individual is classified as being "below the poverty level."

The Empire State Development Corporation has identified 16 industry clusters for New York State. Industry clusters define a set of interdependent and connected companies and businesses that help to support a local economy, such as automobile manufacturing in Detroit, Michigan, and information technology in the Silicon Valley of California. Industry clusters for the state include: back office and outsourcing; biomedical; communications, software, and media services; distribution; electronics and imaging; fashion, apparel, and textiles; financial services; food processing; forest products; front office and producer services; industrial machinery and services; information technology services; materials processing; miscellaneous manufacturing; transportation equipment; and travel and tourism.

Travel and tourism is a large industry in New York State, ranking third in employment of the 16 industry clusters in the state. New York State has many notable attractions, including natural areas (Niagara Falls, the Finger Lakes, and the Adirondack, Catskill, and Allegany Mountains); cultural attractions (museums, arts, theater), and historic sites, many of which are described in Section 2.4.12, Visual Resources. The travel and tourism sector draws from several industries, as shown in Table 2.10 and Table 2.11. Approximately 351,130 persons were employed in the travel and tourism sector in New York State in 2009, including food service (96,990 jobs); culture, recreation, and amusements (84,550 jobs); accommodations (81,780 jobs); passenger transportation (73,180 jobs); and travel retail (14,630) (see Table 2.10). In 2009, wages earned by persons employed in the travel and tourism sector was approximately $12.9 billion dollars, or approximately 2.7% of all wages earned in New York State (NYSDOL 2009b) (see Table 2.11).

In 2009, visitors to New York State spent approximately $4.5 billion in the state (Tourism Economics 2010).

Table 2.10 - New York State: Employment in Travel and Tourism, 2009 (New August 2011)

Industry Group	Number of Jobs	% of Total
Accommodations	81,780	23.3%
Culture, recreation and amusements	84,550	24.1%
Food service	96,990	27.6%
Passenger transportation	73,180	20.8%
Travel retail	14,630	4.2%
Total	351,130	100%

Source: NYSDOL 2009b.

Table 2.11 - New York State: Wages in Travel and Tourism, 2009 (New August 2011)

	Total Wages ($ millions)	Average Wage
Accommodations	$2,928.3	$35,800
Culture, recreation and amusements	$4,355.5	$51,500
Food service	$1,840.9	$18,980
Passenger transportation	$3,478.4	$47,532
Travel retail	$324.1	$22,153
Total	$12,927.3	$36,800

Source: NYSDOL 2009b.

Agriculture is also an important industry for New York State. Table 2.12 provides agricultural statistics for New York State. Approximately 36,352 farms are located in New York State, encompassing 7.2 million acres of land, or 23% of the total land area of the state.

The value of agricultural production in 2009 was $4.4 billion dollars. New York State is a leading producer of milk, fruits (apples, grapes, cherries, pears), and fresh vegetables (sweet corn, onions, and cabbage). Most of the state's field crops (corn, soybeans, and wheat) support its dairy industry (USDA 2007).

Most counties in New York State have placed agricultural land in state-certified agricultural districts, which are managed by the New York State Department of Agriculture and Markets. Farmlands within agricultural districts are provided legal protection, and farmers benefit from preferential real property tax assessment and protection from restrictive local laws, government-funded acquisition or construction projects, and private nuisance suits involving agricultural

practices. Article 25-AA of Agriculture and Markets Law authorizes the creation of local agricultural districts pursuant to landowner initiative, preliminary county review, state certification, and county adoption.

The acreage of land in agricultural districts in New York State is provided on Table 2.12.

Table 2.12 - New York State: Agricultural Data, 2007 (New August 2011)

Number of farms	36,352
Land in farms	7,174,743 acres
Average size of farm	197 acres
Market value of products sold	$4,418.6 million
Principal operator by primary occupation	
Farming	19,624
Other	16,728
Hired farm labor	59,683
Land in state-designated agricultural districts	8,873,157 acres

Source: USDA 2007; NYSDAM 2011.

The oil and gas extraction industry is a relatively small part of the economy of New York State. According to data provided by the U.S. Department of Commerce (USDOC), Bureau of Economic Analysis (BEA), the oil and gas extraction industry accounted for only 0.004% of New York State's GDP in 2009. For comparison purposes, at the national level, the oil and gas extraction industry's 2009 share of the U.S. GDP was 1.01% (USDOC 2010). Consequently, the oil and gas extraction industry is currently of less relative economic importance in New York State than it is at the national level.

The natural gas extraction industry is linked to other industries in New York State through its purchases of their output of goods and services. As a natural gas extraction company increases the number of wells it drills, it needs additional supplies and materials (e.g., concrete) from other industries to complete the wells. The other industries, in turn, need additional goods and services from their suppliers to meet the additional demand. The interrelations between various industries are known as linkages in the economy.

To provide a sense of the direction and magnitude of the linkages for the oil and gas extraction industry, Table 2.13 shows the impact of a $1 million increase in the final demand in the oil and gas extraction industry on the value of the output of other industries in New York State. The data

used to construct the table were drawn from the estimates contained in the BEA's Regional Input-Output Modeling System II (RIMS II). In constructing the table, the initial $1 million increase in the final demand for the output of the oil and gas extraction industry was deducted from the change in its output value to leave just the increase in its output value caused by its purchases of goods and services from other companies in the mining industry, of which it forms a part.

Table 2.13 - New York: Impact of a $1 Million Dollar Increase in the Final Demand in the Output of the Oil and Gas Extraction Industry on the Value of the Output of Other Industries (New August 2011)

Industry	Change in the Value of Output
Real estate and rental and leasing	$47,100
Professional, scientific, and technical services	$30,500
Management of companies and enterprises	$27,600
Construction	$24,300
Manufacturing	$21,000
Finance and insurance	$15,700
Utilities	$12,300
Wholesale trade	$10,800
Information	$7,700
Administrative and waste management services	$5,900
Transportation and warehousing	$3,900
Retail trade	$3,100
Other services	$2,600
Arts, entertainment, and recreation	$1,600
Mining	$1,500
Food services and drinking places	$700
Accommodation	$600
Health care and social assistance	$300
Educational services	$200

Source: US Bureau of Economic Analysis 2011.

As shown in the table above, the oil and gas extraction industry is linked through its purchases of inputs to 18 other major industries (out of a total of 20 industries used by the Regional Input-Output Modeling System II). The largest linkages are to real estate and rental and leasing; professional, scientific, and technical services; management of companies and enterprises; and construction. In total, a $1 million increase in the final demand for the output of the mining industry is estimated to lead to an increase of an additional $217,400 in final output across all industries.

The oil and gas extraction industry accounts for a very small proportion of total employment in New York State. According to the NYSDOL, the oil and gas extraction industry employed 362 people in the state (i.e., less than 0.01% of the state's total employment) (NYSDOL 2009a). Although the number of people employed in the oil and gas extraction industry in New York State is relatively small, the industry has experienced sustained growth in employment during the last few years. Employment in the oil and gas extraction industry in New York State between 2000 and 2010 is shown on Table 2.14. As shown, employment in the industry more than doubled from 2003 to 2010, with the addition of 252 employees during that period.

Table 2.14 - New York State: Employment in the Oil and Gas Extraction Industry, 2000-2010 (New August 2011)

Year	Employment
2000	165
2001	188
2002	193
2003	196
2004	137
2005	163
2006	236
2007	281
2008	341
2009	362
2010	448

Source: NYSDOL 2000 -2008, 2009a, 2010b.
Note: 2010 data are provisional.

A general indication of the types of jobs held by those working in the natural gas extraction industry is provided by looking at the occupational distribution of employment within the oil and gas extraction industry at the national level. Table 2.15 presents employment data on the 20 occupations that accounted for the largest shares of employment in the oil and gas extraction industry at the national level in 2008 (BLS 2011).

Table 2.15 - Most Common Occupations in the U.S. Oil and Gas Extraction Industry, 2008 (New August 2011)

Occupation	% of Industry Employment
Roustabouts, oil and gas	7.45
Petroleum pump system operators, refinery operators, and gaugers	6.07
Petroleum engineers	5.43
Wellhead pumpers	5.41
Accountants and auditors	4.88
General and operations managers	4.18
Geoscientists, except hydrologists and geographers	3.88
Geological and petroleum technicians	3.27
Office clerks, general	3.03
Bookkeeping, accounting, and auditing clerks	2.93
Executive secretaries and administrative assistants	2.77
Secretaries, except legal, medical, and executive	2.49
Service unit operators, oil, gas, and mining	2.50
First-line supervisors/managers of construction trades and extraction workers	2.27
All other engineers	1.74
Business operation specialists, all others	1.72
Financial analysts	1.56
Maintenance and repair workers, general	1.43
Real estate sales agents	1.35
Rotary drill operators, oil and gas	1.33

Source: BLS 2011.

The oil and gas extraction industry is a relatively high-wage industry. In 2009, the average annual wage paid to employees in the industry was $83,606, which is almost 45% above the average annual wages of $57,794 paid to employees across all industries in the state (NYSDOL 2009a). However, national data show that workers in the mining, quarrying, and oil and gas extraction industry have the longest work week among all of the nonagricultural industries. The average work week for all workers aged over 16 in the nonagricultural industries was 38.1 hours long, while the average work week for those in the mining, quarrying, and oil and gas extraction industry was 49.4 hours long (i.e., an almost 30% longer average work week) (BLS 2010).

Table 2.16 presents total and average wages for the oil and gas industry and all industries in New York State. The oil and gas industry was a marginal contributor to total wages in New York State, accounting for $30 million in 2009, or less than 1/100th of a percentage point of total wages across all industries (NYSDOL 2009a).

Table 2.16 - New York State: Wages in the Oil and Gas Industry, 2009 (New August 2011)

	Total Wages ($ million)	**Average Wage**
Oil and gas industry	$30.3	$83,606
Total, all industries	$481,690.6	$57,794

Source: NYSDOL 2009a.

Compared to other parts of the country, New York State currently is a relatively minor natural gas producer. Based on data on natural gas gross withdrawals and production published by the Energy Information Administration (EIA), New York State accounted for 0.2% of the United States' total marketed natural gas production in 2009. During the same period, New York ranked 23rd out of 34 gas-producing areas in the U.S., which included states and the federal Offshore Gulf of Mexico (EIA 2011).

New York State is, however, a major natural gas consumer. Based on data on natural gas consumption by end-use published by the EIA, New York State accounted for 5% of the United States' total consumption of natural gas in 2009. During the same period, New York State was ranked as the 4th largest natural gas consumer among the nation's states (EIA 2011).

By combining the EIA's data on the total consumption and marketed production of natural gas in 2009, there was a difference of approximately 1.1 Tcf between New York State's total consumption and marketed production of natural gas. In 2009, New York State's marketed production was equal to 3.9% of its total consumption.

Table 2.17 shows natural gas production in New York State between 1985 and 2009.

Table 2.17 - New York State: Natural Gas Production, 1985-2009 (New August 2011)

Year	Natural Gas Production (Bcf)
1985	33.1
1986	34.8
1987	29.5
1988	28.1
1989	25.7
1990	25.1
1991	23.4
1992	23.6
1993	22.1
1994	20.5
1995	18.7
1996	18.3
1997	16.2
1998	16.7
1999	16.1
2000	17.7
2001	28.0
2002	36.8
2003	36.0
2004	46.9
2005	55.2
2006	55.3
2007	54.9
2008	50.3
2009	44.9

Source: NYSDEC 1994-2009.

As shown in the table, natural gas production in New York State generally declined between 1986 and 1999, increased steeply until 2005, and then declined toward the end of that decade.

Other indicators of the level of activity in the natural gas extraction industry in New York State are the number of well permits granted, the number of wells completed, and the number of active wells in each year. Table 2.18 shows the number of permits granted for gas wells, the number of gas wells completed, and the number of active gas wells in New York State between 1994 and 2009.

Table 2.18 - Permits Issued, Wells Completed, and Active Wells, NYS Gas Wells, 1994-2009 (New August 2011)

Year	Permits for Gas Wells	Gas Wells Completed	Active Gas Wells
1994	58	97	6,019
1995	38	31	6,216
1996	45	31	5,869
1997	53	22	5,741
1998	68	41	5,903
1999	74	28	5,756
2000	78	112	5,775
2001	127	103	5,949
2002	97	43	5,773
2003	81	31	5,906
2004	133	70	6,076
2005	180	104	5,957
2006	353	191	6,213
2007	386	271	6,683
2008	429	270	6,675
2009	246	134	6,628

Source: NYSDEC 1994-2009.

As with natural gas production, well permits and completions experienced a considerable increase in the 2000s compared to the 1990s, before declining in the late 2000s. This trend most likely reflects the discovery and development of commercial natural gas reserves in the Black River formation in the southern Finger Lakes area along with the impact of higher natural gas prices in the 2000s compared to the 1990s (see Table 2.19). As shown in Table 2.18, active natural gas wells reached a low point in 1997 when only 5,741 wells were active. By 2007, this figure had reached a peak of 6,683 wells.

The level of activity in the natural gas extraction industry is related to the price of natural gas. Table 2.19 shows the average wellhead price for New York State's natural gas for the years 1994 to 2009 inclusive.

Table 2.19 - Average Wellhead Price for New York State's Natural Gas, 1994-2009 (New August 2011)

Year	Price per Mcf
1994	$2.35
1995	$2.30
1996	$2.21
1997	$2.56
1998	$2.46
1999	$2.19
2000	$3.75
2001	$4.85
2002	$3.03
2003	$5.78
2004	$6.98
2005	$7.78
2006	$7.13
2007	$8.85
2008	$8.94
2009	$4.25

Source: NYSDEC 1994-2009.

As shown in the table, the average wellhead price for natural gas remained at relatively low levels in the 1990s, generally increased thereafter, reaching a peak in 2008, and then fell sharply in 2009.

Table 2.20 shows the market value of New York State's natural gas production, which is the price multiplied by the total production.

Table 2.20 - Market Value of New York State's Natural Gas Production, 1994-2009 (New August 2011)

Year	Millions of Dollars
1994	$48.1
1995	$43.0
1996	$40.6
1997	$41.5
1998	$41.1
1999	$34.7
2000	$66.4
2001	$135.5
2002	$111.7
2003	$207.4
2004	$327.7
2005	$429.5
2006	$394.6
2007	$486.0
2008	$450.0
2009	$188.8

Source: NYSDEC 1994-2009.

The combination of generally rising natural gas production and increasing average wellhead prices for much of the 2000s resulted in a substantial increase in the market value of New York State's natural gas production in the 2000s compared to the 1990s. The peak value of $486 million in 2007 was approximately 12 times larger than the average value for the years 1994 to 1999 inclusive (i.e., $41.51 million). However, between 2008 and 2009 the combination of a 10.7% decline in natural gas production and a 52.5% decline in the average wellhead price of natural gas resulted in a 58% decline in the market value of New York State's natural gas production.

Region A

Table 2.21 presents employment, by industry, within Tioga, Broome, and Chemung Counties, and for Region A. The largest employment sector in Region A is the educational, health, and social services sector, with approximately 28.7% of total employment in Region A (USCB 2009a). Manufacturing was the next largest employment sector, accounting for approximately 14.6% of total employment within the region. The economic center for Broome and Tioga Counties is the tri-city area of Binghamton, Endicott, and Johnson City, within the Binghamton Metropolitan Statistical Area (MSA). For Chemung County, the economic center is the city of Elmira.

Table 2.21 - Region A: Area Employment by Industry, 2009 (New August 2011)

	Region A		**Broome County**		**Chemung County**		**Tioga County**	
Sector	**Number of Jobs**	**% of Total**	**Number of Jobs**	**% of Total**	**Number of Jobs**	**% of Total**	**Number of Jobs**	**% of Total**
Agriculture, forestry, fishing, hunting, and mining	1,464	1.0	558	0.6	335	0.9	571	2.3
Construction	8,572	5.6	4,846	5.3	2,054	5.4	1,672	6.8
Manufacturing	22,522	14.6	11,957	13.1	6,030	15.8	4,535	18.5
Wholesale trade	4,749	3.1	3,123	3.4	959	2.5	667	2.7
Retail trade	18,358	11.9	10,721	11.8	4,599	12.1	3,038	12.4
Transportation and warehousing, utilities	5,808	3.8	3,840	4.2	1,228	3.2	740	3.0
Information	3,096	2.0	2,016	2.2	706	1.9	374	1.5
Finance, insurance, real estate, and renting/leasing	7,554	4.9	5,022	5.5	1,719	4.5	813	3.3
Professional, scientific, management, administrative, and waste management services	11,847	7.7	7,140	7.8	2,575	6.8	2,132	8.7

Sector	Region A		Broome County		Chemung County		Tioga County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Educational, health, and social services	44,084	28.7	26,764	29.3	10,869	28.5	6,451	26.4
Arts, entertainment, recreation, accommodation, and food services	11,723	7.6	7,198	7.9	2,928	7.7	1,597	6.5
Other services (except public administration)	6,620	4.3	3,898	4.3	1,786	4.7	936	3.8
Public administration	7,435	4.8	4,154	4.6	2,348	6.2	933	3.8
Total	153,832		91,237		38,136		24,459	

Source: USCB 2009a.

Table 2.22 presents total and average wages across all industries for Region A. The average wages for persons employed across all industries in Region A was $37,875 in 2009.

Table 2.22 - Region A: Wages by Industry, 2009 (New August 2011)

	2009	
	Total Wages ($ millions)	Average Wages
Region A		
Total, all industries	$5,435.03	$37,875
Broome County		
Total, all industries	$3,390.12	$36,802
Chemung County		
Total, all industries	$1,379.61	$36,979
Tioga County		
Total, all industries	$665.30	$47,268

Source: NYSDOL 2009a, 2010b.

The total labor force for Region A is approximately 162,000 workers, of which 60% are in Broome County, 25% are in Chemung County, and 15% are in Tioga County. The annual average unemployment rate in Region A in 2010 was consistent with the overall state average unemployment rate of approximately 8.6% (Table 2.23). The rate of unemployment was slightly higher in Broome County than in Chemung or Tioga Counties. Overall, the size of the labor force has declined between 2000 and 2010 across the region, while the unemployment rate has generally doubled.

Table 2.23 - Region A: Labor Force Statistics, 2000 and 2010 (New August 2011)

	2000	2010
Region A		
Total labor force	167,700	162,000
Employed workers	161,400	148,000
Unemployed workers	6,300	14,000
Unemployment rate (%)	3.8	8.6
Broome County		
Total labor force	98,300	95,700
Employed workers	94,800	87,200
Unemployed workers	3,600	8,500
Unemployment rate (%)	3.6	8.9
Chemung County		
Total labor force	42,800	40,700
Employed workers	41,000	37,300
Unemployed workers	1,800	3,400
Unemployment rate (%)	4.3	8.4
Tioga County		
Total labor force	26,600	25,600
Employed workers	25,600	23,500
Unemployed workers	900	2,100
Unemployment rate (%)	3.4	8.2

Source: NYSDOL 2010a.

Table 2.24 presents per capita income for Region A. Per capita income rose approximately 26.8% between 1999 and 2009. The percentage of individuals living below the poverty level in Region A increased from 12.2% in 1999 to 14.4% in 2009. During the same period, individuals living below the poverty level in New York State as a whole decreased from 14.6% to 13.9% (USCB 2000a, 2009b).

Table 2.24 - Region A: Income Statistics, 1999 and 2009 (New August 2011)

	1999	2009
Region A		
Per capita income	$18,854	$23,912
% Below the poverty level[1]	12.2	14.4
Broome County		
Per capita income	$19,168	$24,432
% Below the poverty level[1]	12.8	15.0
Chemung County		
Per capita income	$18,264	$22,691
% Below the poverty level[1]	13.0	15.8
Tioga County		
Per capita income	$18,673	$24,034
% Below the poverty level[1]	8.4	10.0

Source: USCB 2000a, 2009b.

1 If the total income for an individual falls below relevant poverty thresholds, updated annually relative to the Consumer Price Index for All Urban Consumers, then the individual is classified as being "below the poverty level."

The five largest employers in the Binghamton MSA, which includes Broome and Tioga Counties are United Health Services, (3,300 employees); Lockheed Martin, (3,000 employees); Broome County (2,500 employees); the State University of New York Binghamton University (2,300 employees); and Lourdes Hospital (2,300 employees) (BCIDA 2010). The largest employer in Chemung County is St. Joseph's Hospital (1,000-1,200 employees) (STC Planning 2009).

The Empire State Development Corporation has identified 16 industry clusters for the Southern Tier Region of the state, which encompasses Region A (Broome, Chemung, and Tioga Counties) as well as Chenango, Delaware, Schuyler, Steuben, and Tompkins Counties. The industry clusters that support the largest number of jobs are industrial machinery and services, travel and tourism, financial services, front office and producer services, and electronics and imaging.

Travel and tourism is a large industry for the Southern Tier Region (which includes Region A), ranking second in employment of the 16 industry clusters in the Southern Tier Region. Broome and Tioga Counties are part of the Susquehanna Heritage Area, and Chemung County considers itself the gateway to the Finger Lakes Region. Various attractions and natural areas are described in more detail in Section 2.4.11, Visual Resources, and Section 2.4.14, Community Character. The travel and tourism industry employs approximately 4,590 persons throughout Region A (NYSDOL 2009b), primarily in food service (2,000 workers) and accommodations (1,190 workers) (Table 2.25). In 2009, wages earned by persons employed in the travel and tourism sector were approximately $78.6 million, or about 1.5% of all wages earned in Region A (NYSDOL 2009b) (Table 2.26).

Table 2.25 - Region A: Employment in Travel and Tourism, 2009 (New August 2011)

Industry Group	Region A		Broome County		Chemung County		Tioga County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Accommodations	1,190	25.9	830	27.8	210	18.3	150	33.3
Culture, recreation, and amusements	530	11.5	320	10.7	100	8.7	110	24.4
Food service	2,000	43.6	1,340	44.8	530	46.1	130	28.9
Passenger transportation	540	11.8	330	11.0	210	18.3	0	-
Travel retail	330	7.2	170	5.7	100	8.7	60	13.3
Total	4,590		2,990		1,150		450	

Source: NYSDOL 2009b.

Table 2.26 - Region A: Wages in Travel and Tourism, 2009 (New August 2011)

	2009	
	Total Wages (millions)	Average Wages
Region A	$78.6	$17,100
Broome County	$50.3	$16,800
Chemung County	$20.9	$18,100
Tioga County	$7.4	$16,100

Source: NYSDOL 2009b.

Agriculture is also an important industry within Region A. Table 2.27 provides agricultural statistics for Broome, Chemung, and Tioga Counties. Approximately 1,518 farms are located in Region A, encompassing 258,571 acres of land. The value of agricultural production in 2009 was $83.2 million dollars (USDA 2007). The principal source of farm income is dairy products, which account for 70% of the agricultural sales in Broome County, and 75% of the sales in Tioga County (USDA 2007).

Table 2.27 - Region A: Agricultural Data, 2007 (New August 2011)

	Region A	Broome County	Chemung County	Tioga County
Number of farms	1,518	580	373	565
Land in farms (acres)	258,571	86,613	65,124	106,834
Average size of farm (acres)	170	149	175	189
Market value of Products Sold ($ millions)	83.2	29.9	16.6	36.7
Principal operator by primary occupation				
Farming	681	252	183	246
Other	837	328	190	319
Hired farm labor	971	340	238	393
Land in state-designated agricultural districts	278,935	153,233	41,966	83,736

Source: USDA 2007; NYSDAM 2011.

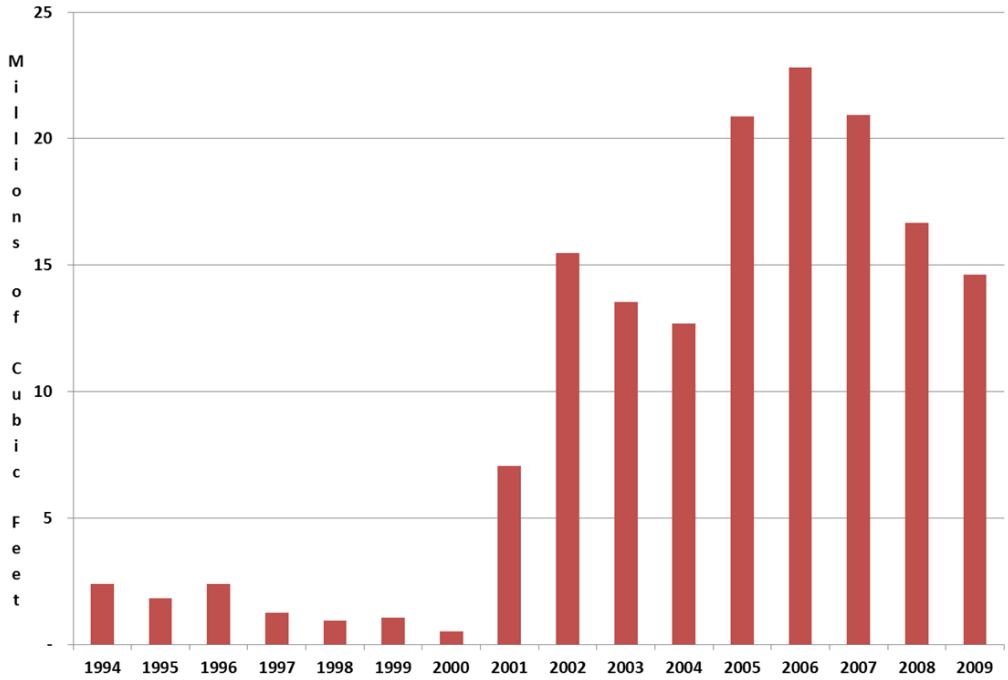
Approximately 125 persons are employed in the oil and gas industry in Region A, or about 34.5% of persons working in the oil and gas industry in New York State (NYSDOL 2009a, 2010b). Workers are primarily employed in Chemung County, as the data on oil and gas industry employment in Broome and Tioga Counties is so low as to not be reported due to business confidentiality reasons.

The oil and gas industry was a marginal contributor to total wages in Region A in 2009. Total wages for persons employed in the oil and gas industry in Chemung County were $12.5 million, or about 0.2% of total wages across all industries (NYSDOL 2009a, 2010b). The average annual wage for workers employed in the oil and gas sector in Chemung County was $99,600 in 2009.

In the 1990s, Region A was a minor contributor to New York State's natural gas production. However, starting in 2001, Region A experienced a substantial increase in its gas production, reaching a peak in 2006 before declining in each of the following three years (Figure 2.5).

Table 2.28 shows the number of active natural gas wells operating in Region A from 1994 to 2009. As shown on the table, the number of active wells in Region A has been steadily increasing since 1995.

Figure 2.5 - Region A: Natural Gas Production, 1994 to 2009 (New August 2011)



Source: NYSDEC 1994-2009.

Table 2.28 - Region A: Number of Active Natural Gas Wells, 1994-2009 (New August 2011)

Year	No. of Gas Wells
1994	15
1995	12
1996	15
1997	16
1998	17
1999	20
2000	19
2001	25
2002	29
2003	30
2004	36
2005	38
2006	37
2007	40
2008	41
2009	46

Source: NYSDEC 1994-2009.

In 2009, the average annual output per well in Region A was 317.9 MMcf of natural gas. The average production per well in Region A was greater (by a factor of 47) than the statewide average of 6.8 MMcf (NYSDEC 2009).

Table 2.29 shows the production of natural gas and the number of active wells, by town, within each county in Region A for 2009. As shown in the table, Chemung County accounted for nearly all of the natural gas production and active wells in Region A. There were no active natural gas wells in Broome County in 2009.

Table 2.29 – Natural Gas Production and Active Wells by Town within each County in Region A, 2009 (New August 2011)

Location	Natural Gas Production (Mcf)	Number of Active Gas Wells
Region A	**14,623,232**	**46**
Chemung County	13,890,161	45
Baldwin	327,738	1
Big Flats	2,095,184	4
Catlin	1,441,322	9
Elmira City	2,685	1
Erin	4,037,072	6
Horseheads	4,910	0
Southport	1,752,131	5
Van Etten	3,048,850	12
Veteran	1,180,269	7
Tioga County	733,071	1
Spencer	733,071	1

Source: NYSDEC 2009.

Region B

Table 2.30 presents employment, by industry, within Sullivan, Delaware, and Otsego Counties (Region B). The largest employment sectors are educational, health, and social services (30.1% of workers); retail trade (11.6%) arts, entertainment, recreation, accommodation, and food services (10.1%). This region also has a comparatively high number of employment in the agriculture, forestry, fishing, hunting, and mining sector (2.9%), particularly Delaware County (5.2%), compared to New York State as a whole (0.6%) (USCB 2009a).

Table 2.30 - Region B: Area Employment, by Industry, 2009 (New August 2011)

Industry Sector	Region B		Sullivan County		Delaware County		Otsego County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Agriculture, forestry, fishing, hunting, and mining	2,498	2.9	591	1.7	1,102	5.2	805	2.7
Construction	7,276	8.5	3,178	9.2	2,051	9.7	2,047	6.8
Manufacturing	6,442	7.5	1,504	4.4	2,565	12.2	2,373	7.9
Wholesale Trade	2,134	2.5	924	2.7	432	2.0	778	2.6
Retail Trade	9,900	11.6	3,740	10.9	2,362	11.2	3,798	12.6
Transportation and warehousing, utilities	3,626	4.3	1,710	5.0	897	4.2	1,019	3.4
Information	1,493	1.7	696	2.0	323	1.5	474	1.6
Finance, insurance, real estate, and renting/leasing	4,373	5.1	2,034	5.9	737	3.5	1,602	5.3
Professional, scientific, management, administrative, and waste management services	4,618	5.4	2,006	5.8	1,113	5.3	1,499	5.0
Educational, health, and social services	25,788	30.1	10,368	30.1	5,564	26.4	9,856	32.8
Arts, entertainment, recreation, accommodation, and food services	8,630	10.1	3,494	10.1	1,845	8.7	3,291	11.0
Other services (except public administration)	4,248	5.0	1,818	5.3	1,069	5.1	1,361	4.5
Public administration	4,571	5.3	2,377	6.9	1,051	5.0	1,143	3.8
Total	**85,597**		**34,440**		**21,111**		**30,046**	

Source: USCB 2009a.

Table 2.31 presents total and average wages across all industries for Region B. The average wages for persons employed across all industries in Region B was $35,190 in 2009.

Table 2.31 - Region B: Wages, by Industry, 2009 (New August 2011)

	2009	
	Total Wages (millions)	Average Wages
Region B		
Total, all industries	$2,266.66	$35,190
Delaware County		
Total, all industries	$544.78	$34,655
Chemung County		
Total, all industries	$830.49	$35,310
Tioga County		
Total, all industries	$891.39	$35,412

Source: NYSDOL 2000ba, 2010b.

The total labor force for Region B is approximately 88,500 workers, of which 40% are in Sullivan County, 35% are in Otsego County, and 25% are in Delaware County. As shown in Table 2.32, the 2010 annual average unemployment rate in Region B was approximately 8.5%, similar to New York State as a whole. Among the counties that comprise Region B, Sullivan County had the highest average unemployment rate, approximately 9.2% (NYSDOL 2010a).

Table 2.32 - Region B: Labor Force Statistics, 2000 and 2010 ((New August 2011))

	2000	2010	Percent Change
Region B			
Total labor force	85,200	88,500	3.9
Employed workers	81,500	81,000	-0.6
Unemployed workers	3,600	7,500	108.3
Unemployment rate	4.2	8.5	102.3
Delaware County			
Total labor force	22,200	22,000	-0.9
Employed workers	21,300	20,100	-5.6
Unemployed workers	900	1,900	111.1
Unemployment rate (%)	4.2	8.7	107.1
Otsego County			
Labor force	29,800	31,500	5.7
Employed workers	28,500	29,100	2.1
Unemployed workers	1,300	2,400	84.6
Unemployment rate (%)	4.2	7.7	83.3
Sullivan County			
Labor force	33,200	35,000	5.4
Employed workers	31,700	31,800	0.3
Unemployed workers	1,400	3,200	128.6
Unemployment rate (%)	4.3	9.2	114.0

Source: NYSDOL 2010a.

Table 2.33 presents per capita income data for Region B. From 1999 to 2009, per capita income across the region increased by 27.9%. Individuals living below the poverty level in Region B increased from 14.9% in 1999 to 15.0% in 2009 (USCB 2000a, 2009b).

Table 2.33 - Region B: Income Statistics, 1999 and 2009 (New August 2011)

	1999	2009
Region B		
Per capita income	$17,790	$22,750
% Below the poverty level[1]	14.9	15.0
Delaware County		
Per capita income	$17,357	$22,199
% Below the poverty level[1]	12.9	15.1
Otsego County		
Per capita income	$16,806	$22,255
% Below the poverty level[1]	14.9	15.2
Sullivan County		
Per capita income	$18,892	$23,491
% Below the poverty level[1]	16.3	14.7

Source: U.S. Census 2000a, 2009b.

[1] If the total income for an individual falls below relevant poverty thresholds, updated annually relative to the Consumer Price Index for All Urban Consumers, then the individual is classified as being "below the poverty level."

The five largest employers in Delaware and Otsego Counties are: Bassett Healthcare (3,200+ employees), Amphenol Corporation (1,400 employees), State University of New York College Oneonta (1,181 employees); New York Central Mutual Fire Insurance Company (1,000 employees) and A.O. Fox Hospital (1,000 employees) (Bassett Healthcare 2011; Delaware County Economic Development 2010; Otsego County 2010).

The counties within Region B are part of three economic development regions, as defined by the Empire State Development Corporation, including the Southern Tier Region (Delaware County), Mid-Hudson Region (Sullivan County), and Mohawk Valley Region (Otsego County). Ranked by employment, travel and tourism is the lead employment industry cluster for the Mid-Hudson Region, and the second largest employment industry cluster in the Southern Tier and Mohawk Valley Regions. The tourism industry is an important economic driver in Region B, particularly in Otsego and Sullivan Counties, with the Catskill Mountains, as well as popular destinations such as the Baseball Hall of Fame in the village of Cooperstown (Otsego County) and the Monticello Raceway in the village of Monticello (Sullivan County). Approximately 4,560 persons were employed in the travel and tourism sector in Region B in 2009, including accommodations (1,820 jobs), and culture, recreation, and amusements (960 jobs), food service (930 jobs), passenger transportation (250 jobs), and travel retail (600 jobs) (Table 2.34). In 2009

wages earned by persons employed in the travel and tourism sector was approximately $72.3 million, or about 3.4% of all wages earned in Region B (NYSDOL 2009b) (Table 2.35).

Table 2.34 - Region B: Travel and Tourism, by Industrial Group, 2009 (New August 2011)

Industry Group	Region B		Delaware County		Otsego County		Sullivan County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Accommodations	1,820	39.9%	150	11.7%	530	35.3%	1,140	64.0%
Culture, recreation, and amusements	960	21.1%	100	7.8%	500	33.3%	360	20.2%
Food service	930	20.4%	360	28.1%	360	24.0%	210	11.8%
Passenger transportation	250	5.5%	150	11.7%	60	4.0%	40	2.2%
Travel retail	600	13.2%	520	40.6%	50	3.3%	30	1.7%
Total	4,560		1,280		1,500		1,780	

Source: NYSDOL 2009b.

Table 2.35 - Region B: Wages in Travel and Tourism, 2009 (New August 2011)

	2009	
	Total Wages (millions)	Average Wage
Region B	$72.3	$19,500
Delaware County	$6.5	$15,400
Otsego County	$28.6	$19,200
Sullivan County	$37.2	$20,900

Source: NYSDOL 2009b.

Agriculture also is an important industry within Region B. Table 2.36 provides agricultural statistics for Delaware, Otsego, and Sullivan Counties. Approximately 2,050 farms are located in Region B, encompassing 392,496 acres of land. The value of agricultural production in 2009 was $148.7 million dollars (USDA 2007). The principal sources of farm income in the region are dairy products (particularly in Otsego and Delaware Counties, where dairy products accounted for 70% and 62% of the agricultural sales in the county, respectively) and poultry and eggs (particularly in Sullivan County, where poultry and eggs accounted for 65% of the sales in the county) (USDA 2007).

Table 2.36 - Region B: Agricultural Data, 2007 (New August 2011)

	Region B	Delaware County	Otsego County	Sullivan County
Number of farms	2,050	747	980	323
Land in farms (acres)	392,496	165,572	176,481	50,443
Average size of farm (acres)	191	222	180	156
Market value of Products Sold ($ millions)	$148.7	$55.1	$51.4	$42.1
Principal operator by primary occupation				
Farming	1,139	437	538	164
Other	911	310	442	159
Hired farm labor	1,746	760	574	412
Land in state designated agricultural districts	588,443	237,385	189,291	161,767

Source: USDA 2007; NYSDAM 2011.

Currently, there are no producing natural gas wells in Region B, although some exploratory well activity occurred in 2007 and 2009.

Region C

Table 2.37 presents employment by industry within Chautauqua and Cattaraugus Counties, and for Region C. The largest employment sectors in Region C are education, health, and social services sector (26.7% of total employment), manufacturing (16.5% of total employment), and retail trade (11.6%). The agriculture, forestry, fishing, hunting, and mining sector accounted for about 2.9% of total employment in the region, which is relatively high compared to New York State as a whole, which had 0.6% of its workforce employed in this sector (USCB 2009a).

Table 2.37 - Region C: Area Employment by Industry, 2009 (New August 2011)

Sector	Region C		Cattaraugus County		Chautauqua County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Agriculture, forestry, fishing, hunting, and mining	2,813	2.9	1,136	3.1	1,677	2.8
Construction	6,042	6.2	2,825	7.6	3,217	5.3
Manufacturing	16,194	16.6	5,752	15.5	10,442	17.2
Wholesale trade	2,620	2.3	879	2.4	1,741	2.9
Retail trade	11,392	11.7	4,432	11.9	6,960	11.5
Transportation and warehousing, utilities	4,116	4.2	1,398	3.7	2,718	4.4
Information	1,578	1.6	525	1.4	1,053	1.7
Finance, insurance, real estate, and renting/leasing	3,486	3.6	1,289	3.5	2,197	3.6
Professional, scientific, management, administrative, and waste management services	4,816	4.9	1,898	5.1	2,918	4.8
Educational, health, and social services	26,161	26.8	9,575	25.7	16,586	27.3
Arts, entertainment, recreation, accommodation, and food services	9,581	9.8	3,893	10.4	5,688	9.4
Other services (except public administration)	4,225	4.3	1,468	3.9	2,757	4.5
Public administration	4,960	5.1	2,150	5.8	2,810	4.6
	97,984		37220		60,764	

Source: USCB 2009a.

Table 2.38 presents total and average wages across all industries for Region C. The average wages for persons employed across all industries in Region C was $32,971 in 2009.

Table 2.38 - Region C: Wages, by Industry, 2009 (New August 2011)

	2009	
	Total Wages (millions)	Average Wages
Region C		
Total, all industries	$2,732.72	$32,971
Cattaraugus County		
Total, all industries	$1,046.92	$34,428
Chautauqua County		
Total, all industries	$1,685.80	$32,127

Source: NYSDOL 2009a, 2010b.

The total labor force for Region C is approximately 105,800 workers, of which 61% are in Chautauqua County, and 39% are in Cattaraugus County. As shown in Table 2.39, the 2010 annual average unemployment rate in Region C was approximately 8.9%. The size of the labor force decreased by 3.1% between 2000 and 2010 across the region, and the unemployment rate has generally doubled.

Table 2.39 - Region C: Labor Force Statistics, 2000 and 2010 (New August 2011)

	2000	2010
Region C		
Labor force	109,200	105,800
Employed workers	104,700	96,400
Unemployed workers	4,600	9,400
Unemployment rate (%)	4.2	8.9
Cattaraugus County		
Labor force	41,100	41,200
Employed workers	39,300	37,400
Unemployed workers	1,900	3,800
Unemployment rate (%)	4.5	9.2
Chautauqua County		
Labor force	68,100	64,600
Employed workers	65,400	59,000
Unemployed workers	2,700	5,600
Unemployment rate (%)	4.0	8.7

Source: NYSDOL 2010a.

Table 2.40 presents per capita income data for Region C. Per capita income in Region C rose approximately 26.2% between 1999 and 2009. The number of individuals living below the poverty level in Region C increased from 13.8% in 1999 to 16.1% in 2009.

Table 2.40 - Region C: Income Statistics, 1999 and 2009 (New August 2011)

	1999	2009
Region C		
Per capita income	$16,509	$20,830
% Below the poverty level[1]	13.8	16.1
Cattaraugus County		
Per capita income	$15,959	$20,508
% Below the poverty level[1]	13.7	15.7
Chautauqua County		
Per capita income	$16,840	$21,023
% Below the poverty level[1]	13.8	16.3

Source: U.S. Census 2000a, 2009b.

[1] If the total income for an individual falls below relevant poverty thresholds, updated annually relative to the Consumer Price Index for All Urban Consumers, then the individual is classified as being "below the poverty level."

The five largest employers in Region C are Dresser-Rand Company (3,300 employees); The Resource Center, Chautauqua County (1,748 employees); Chautauqua County (1,366 employees); Cummins Engine, Chautauqua County (1,300 employees); and Cattaraugus County (1,180 employees) (Buffalo Business First 2011).

The Empire State Development Corporation has identified 16 industry clusters for the Western New York Region of the state, which encompasses Cattaraugus and Chautauqua Counties, as well as Erie (City of Buffalo), Niagara (City of Niagara Falls), and Allegany Counties. The industry clusters that support the largest number of jobs are front office and producer services, financial services, travel and tourism, industrial machinery and services, and distribution. Travel and tourism is the third largest industry cluster in terms of employment in the Western New York Region.

Tourism is a significant component of the economy in Region C. Cattaraugus County, known as the Enchanted Mountains Region, boasts abundant recreational opportunities that primarily revolve around its natural resources. Popular tourist destinations include Allegany State Park, the Amish Trail, Holiday Valley Ski Resort, Rock City Park, Griffis Sculpture Park, and the Seneca-Allegany Casino. Chautauqua County is also recognized for its natural resources and unique learning destinations associated with the Chautauqua Institute. Approximately 4,040 persons were employed in the travel and tourism sector in Region C in 2009, including accommodations (1,110 jobs); culture, recreation, and amusements (1,220 jobs); food service (1,210 jobs); passenger transportation (280 jobs); and travel retail (220 jobs) (Table 2.41). In 2009, wages earned by persons employed in the travel and tourism sector were approximately $77.5 million, or about 3.0% of all wages earned in Region C (NYSDOL 2009b) (Table 2.42).

Table 2.41 - Region C: Travel and Tourism, by Industrial Group, 2009 (New August 2011)

Industry Group	Region C		Cattaraugus County		Chautauqua County	
	Number of Jobs	**% of Total**	**Number of Jobs**	**% of Total**	**Number of Jobs**	**% of Total**
Accommodations	1,110	27.5%	180	10.5%	930	40.1%
Culture, Recreation and Amusements	1,220	30.2%	1,050	61.0%	170	7.3%
Food Service	1,210	30.0%	380	22.1%	830	35.8%
Passenger Transportation	280	6.9%	30	1.7%	250	10.8%
Travel Retail	220	5.4%	80	4.7%	140	6.0%
Total	**4,040**		**1,720**		**2,320**	

Source: NYSDOL 2009b.

Table 2.42 - Region C: Wages in Travel and Tourism, 2009 (New August 2011)

	2009	
	Total Wages (millions)	**Average Wage**
Region C	$77.5	$19,200
Cattaraugus County	$39.7	$23,300
Chautauqua County	$37.8	$16,300

Source: NYSDOL 2009b.

Agriculture is also an important industry within Region C. Table 2.43 provides agricultural statistics for Cattaraugus and Chautauqua Counties. Approximately 2,770 farms are located in Region C, encompassing 419,297 acres of land. The value of agricultural production in 2009 was $213.7 million dollars (USDA 2007). Dairy products account for approximately 68% of agricultural sales in Cattaraugus County. In Chautauqua County, the principal sources of farm income are grape and dairy products (USDA 2007). Grapes and grape products account for approximately 30% of agricultural sales in Chautauqua County, and dairy products account for approximately 51% of agricultural sales (USDA 2007).

Table 2.43 - Region C: Agricultural Data, 2007 (New August 2011)

	Region C	Cattaraugus County	Chautauqua County
Number of farms	2,770	1,112	1,658
Land in farms (acres)	419,297	183,439	235,858
Average size of farm (acres)	151	163	142
Market value of Products Sold ($ millions)	$213.7	$75.2	$138.6
Principal operator by primary occupation			
Farming	1,437	550	887
Other	1,343	572	771
Hired farm labor	4,341	994	3,347
Land in state-designated agricultural districts	631,686	239,641	392,045

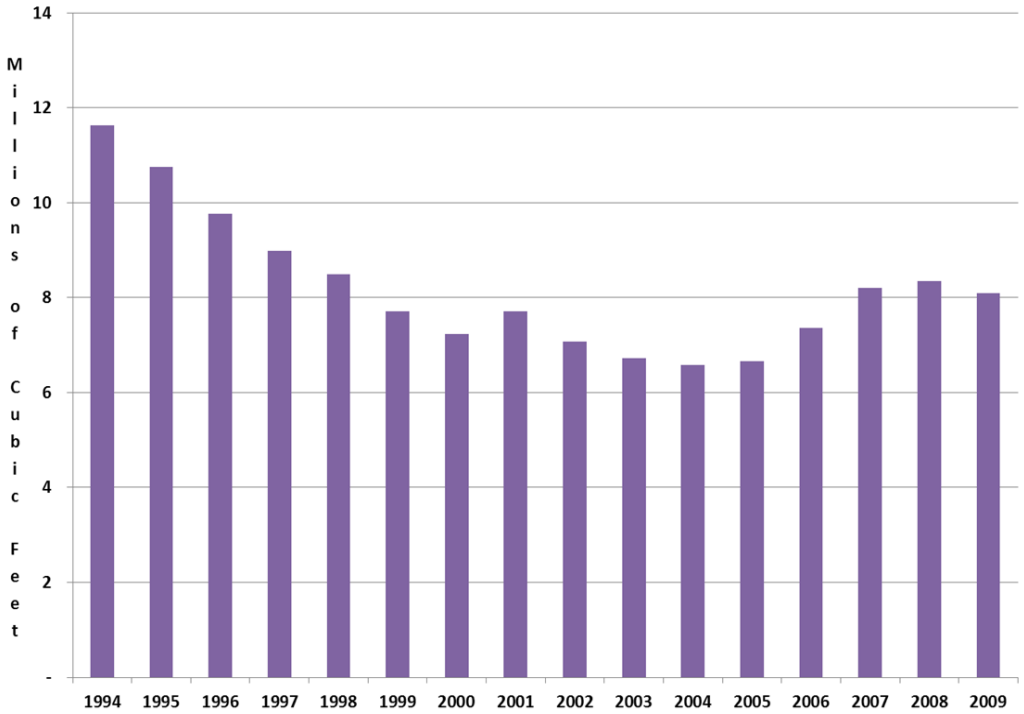
Source: USDA 2007; NYSDAM 2011.

Approximately 157 persons are employed in the oil and gas industry in Region C, or approximately 43.4% of all persons working in the oil and gas industry in New York State in 2009 (NYSDOL 2009a, 2010b).

The oil and gas industry was a marginal contributor to total wages in Region C in 2009. The total wages for persons employed in the oil and gas industry in the region were $10.8 million, or about 0.4% of the total wages across all industries (NYSDOL 2009a). The average annual wages for workers employed in the oil and gas sector varied greatly between the counties in Region C. The average annual wage for oil and gas workers in Cattaraugus County was $44,978 in 2009, whereas the average annual wage for oil and gas workers in Chautauqua County was $76,970 during the same time period (NYSDOL 2009a).

Natural gas production in Region C is shown on Figure 2.6. In the mid-1990s, Region C produced nearly 12 MMcf of natural gas per year. Production has declined from that level over the last 15 years, and the region is now producing slightly more than 8 MMcf of natural gas per year.

Figure 2.6 - Region C: Natural Gas Production, 1994-2009 (New August 2011)



Source: NYSDEC 1994-2009.

The total number of active natural gas wells in Region C over the period 1994 to 2009 is shown on Table 2.44. As shown in the table, the number of active natural gas wells in Region C has increased by nearly 400 wells since 1994, to a total of 3,917 wells.

Table 2.44 - Number of Active Natural Gas Wells in Region C, 1994-2009 (New August 2011)

Year	No. of Gas Wells
1994	3,523
1995	3,759
1996	3,512
1997	3,427
1998	3,585
1999	3,590
2000	3,545
2001	3,579
2002	3,350
2003	3,470
2004	3,645
2005	3,629
2006	3,740
2007	3,935
2008	3,984
2009	3,917

Source: NYSDEC 1994-2009.

In 2009 the average annual output per well in Region C was only 2.1 MMcf of natural gas. Production per well was significantly less than the average annual output per well in Region A (317.9 MMcf) or the statewide average per well (6.8 MMcf) (NYSDEC 2009). Because of this low productivity per well, Region C is currently a minor contributor to New York State's natural gas production, even though it accounts for the largest number of active wells in the state (NYSDEC 2009).

Table 2.45 shows the production of natural gas and the number of active wells, by town, within each county in Region C in 2009. As shown in the table, in 2009 there were 530 active gas wells in Cattaraugus County and 3,387 active gas wells in Chautauqua County (NYDEC 2009).

Table 2.45 - Natural Gas Production and the Number of Active Gas Wells by Town within each County in Region C, 2009 (New August 2011)

Location	Natural Gas Production (Mcf)	Number of Active Gas Wells
Region C	**14,623,232**	**46**
Cattaraugus County	1,615,243	530
Allegany	255,057	6
Ashford	10,416	11
Carrollton	89,633	3
Conewango	154,745	76
Dayton	113,159	59
East Otto	96,897	15
Ellicottville	737	3
Farmersville	214	2
Freedom	3,845	4
Leon	249,247	88
Machias	100	1
Napoli	1,187	2
New Albion	7,220	9
Olean	7,163	5
Otto	69,647	70
Perrysburg	343,006	42
Persia	99,100	43
Randolph	72,434	72
South Valley	892	2
Yorkshire	40,544	17
Chautauqua County	6,473,408	3,387
Arkwright	106,655	122
Busti	321,152	121
Carroll	181,427	70
Charlotte	230,836	127

Location	Natural Gas Production (Mcf)	Number of Active Gas Wells
Chautauqua	469,915	314
Cherry Creek	179,037	123
Clymer	159,828	101
Dunkirk	69,003	36
Dunkirk City	10,169	6
Ellery	180,187	82
Ellicott	204,129	66
Ellington	264,581	180
French Creek	26,003	40
Gerry	437,202	152
Hanover	450,439	152
Harmony	231,897	116
Jamestown	4,183	3
Kiantone	425,027	84
Mina	53,986	71
North Harmony	352,930	159
Poland	554,983	159
Pomfret	189,905	174
Portland	235,705	149
Ripley	185,487	182
Sheridan	142,294	86
Sherman	106,236	84
Stockton	169,836	118
Villanova	141,171	57
Westfield	389,205	253

Source: NYSDEC 2009.

2.4.11.2 Population

The following subsection discusses the past, current and projected population for New York State, and the local areas within each of the three regions (Region A, B and C).

New York State

New York State is the third most populous state in the country, with a 2010 population of approximately 19.38 million (USCB 2010) (see Table 2.46). The population density of the state is 410 persons per square mile. Nearly half of the population in the state is located within NYC (8.1 million persons). Subtracting out the population of NYC, the average population density of the rest of New York State is 237.3 persons per square mile. New York State's population has continually increased during the past 20 years, though the rate of growth was faster from 1990 to 2000 than it was from 2000 to 2010 (see Table 2.46).

Table 2.46 - New York State: Historical and Current Population, 1990, 2000, 2010 (New August 2011)

	Total Population	Percent Change	Average Annual Growth Rate	Average Population Density
2010	19,378,102	2.1%	0.2%	410.4
2000	18,976,457	5.5%	0.5%	401.9
1990	17,990,455	--	--	381.0

Source: USCB 1990a, 2000b, and 2010.

Table 2.47 shows the state's total 2010 population and presents population projections for 2015 to 2030. As shown, the population in New York State is projected to continue to grow through 2030. The state's population is projected to grow at an average annual rate of 0.2% between 2015 and 2030. By 2030, New York State's population is projected to reach 20,415,446 persons.

Table 2.47 - New York State: Projected Population, 2015 to 2030 (New August 2011)

Population 2010[a] (actual)	Population 2015[b] (projected)	Population 2020[b] (projected)	Population 2025[b] (projected)	Population 2030[b] (projected)	Average Annual Growth Rate 2015-2030
19,378,102	19,876,073	20,112,402	20,299,512	20,415,446	0.2%

Sources:
[a] USCB 2010.
[b] Cornell University 2009.

Region A

Table 2.48 provides the 1990, 2000 and 2010 population for Region A and for each of the three counties within this region. The population of Region A is 342,390 persons (USCB 2010), with an average population density of 209 persons per square mile. Since 1990, all three counties within Region A have lost population. Between 1990 and 2000, the region lost population at a rate of approximately 0.5% per year, and between 2000 and 2010, the region lost population at a rate of approximately 0.1% per year.

Table 2.48 - Region A: Historical and Current Population, 1990, 2000, 2010 (New August 2011)

Year	1990	2000	2010
Region A			
Total Population	359,692	343,390	340,555
Percent Change	--	-4.5%	-0.8%
Average Annual Growth Rate	--	-0.5%	-0.1%
Average Population Density	220.1	210.2	208.5
Broome County			
Population	212,160	200,536	200,600
Percent Change	--	-5.5%	<0.1%
Average Annual Growth Rate	--	-0.6%	< 0.1%
Average Population Density	300.2	283.7	283.8
Chemung County			
Population	95,195	91,070	88,830
Percent Change	--	-4.3%	-2.5%
Average Annual Growth Rate	--	-0.4%	-0.3%
Average Population Density	233.2	223.1	217.6
Tioga County			
Population	52,337	51,784	51,125
Percent Change	--	-1.1%	-1.3%
Average Annual Growth Rate	--	-0.1%	-0.1%
Average Population Density	100.9	99.8	98.6

Source: USCB 1990a, 2000b, and 2010.

The City of Binghamton has the largest population in the region, with a population in 2010 of 47,376; this is 13.9% of Region A's population as a whole. Other large population centers in the region include City of Elmira (29,200 persons), Village of Johnson City (15,174), and Village of Endicott (13,392 persons).

Region A's population has continually decreased during the past 20 years, though the rate of decline was faster from 1990 to 2000 than it was from 2000 to 2010 (see Table 2.48).

Table 2.49 shows Region A's total 2010 population and presents population projections for 2015 to 2030 (Cornell University 2009). As shown in Table 2.49, the population of Region A is projected to continue to decrease through 2030. The population of the Region is projected to decrease at an average annual rate of 0.7% between 2015 and 2030. By 2030, Region A's population is projected to be 279,675, which would be a decrease of 19% from the 2010 census population.

Table 2.49 - Region A: Population Projections, 2015 to 2030 (New August 2011)

County/ Region	Population 2010[a] (actual)	Population 2015[b] (projected)	Population 2020[b] (projected)	Population 2025[b] (projected)	Population 2030[b] (projected)	Average Annual Growth Rate 2015-2030
Broome	200,600	183,115	176,715	169,968	162,750	-0.7%
Chemung	88,830	83,282	80,643	77,773	74,614	-0.7%
Tioga	51,125	48,089	46,412	44,481	42,311	-0.8%
Region A Total	340,555	314,486	303,770	292,222	279,675	-0.7%

Sources: [a] USCB 2010; [b] Cornell University 2009.

Region B

Table 2.50 provides the 1990, 2000 and 2010 population for Region B and for each of the three counties within this region. The population of Region B is 187,786 persons (USCB 2010), with an average population density of 59.6 persons per square mile. The region has gained population over the last 20 years, primarily in Sullivan County. Between 1990 and 2000, the population grew at a rate of approximately 0.4% per year, and between 2000 and 2010, population increased at a rate of approximately 0.2% per year. Since 1990 the population of Region B has increased by 10,767, which is an increase of approximately 6.1%.

Table 2.50 - Region B: Historical and Current Population - 1990, 2000, 2010 (New August 2011)

	1990	2000	2010
Region B			
Population	177,019	183,697	187,786
Percent Change	--	3.8%	2.2%
Average Annual Growth Rate	--	0.4%	0.2%
Average Population Density	56.2	58.3	59.6
Delaware County			
Population	47,225	48,055	47,980
Percent Change	--	1.8%	-0.2%
Average Annual Growth Rate	--	0.2%	< 0.0%
Average Population Density	32.7	33.2	33.2
Otsego County			
Population	60,517	61,676	62,259
Percent Change	--	1.9%	1.0%
Average Annual Growth Rate	--	0.2%	0.1%
Average Population Density	60.4	61.5	62.1
Sullivan County			
Population	69,277	73,966	77,547
Percent Change	--	6.8%	4.8%
Average Annual Growth Rate	--	0.7%	.5%
Average Population Density	71.4	76.3	80.0

Source: USCB 1990a, 2000b, and 2010.

The two largest population centers in Region B are the City of Oneonta (13,901 persons) in Otsego County and the Village of Monticello (6,726 persons) in Sullivan County.

Region B's population has continually increased during the past 20 years, though the rate of growth has declined from the 1990 to 2000 period to the 2000 to 2010 period (see Table 2.50). Table 2.51 shows Region B's total 2010 population and presents population projections for 2015 to 2030 (Cornell University 2009). As shown in Table 2.51, the population in Region B overall is projected to decrease through 2030, although the population in Otsego County will increase slightly through 2025, then decline in 2030, and the population in Sullivan County will increase slightly between 2015 and 2030. By 2030, Region B's population is projected to be 183,031, which would be a decrease of 2.5% from the 2010 census population.

Table 2.51 - Region B: Population Projections, 2015 to 2030 (New August 2011)

County/ Region	Population 2010[a] (actual)	Population 2015[b] (projected)	Population 2020[b] (projected)	Population 2025[b] (projected)	Population 2030[b] (projected)	Average Annual Growth Rate 2015-2030
Delaware	47,980	44,644	42,995	40,980	38,631	-0.9%
Otsego	62,259	63,820	64,344	64,597	64,508	0.1%
Sullivan	77,547	78,329	79,322	79,845	79,892	0.1%
Region B Total	**187,786**	**186,793**	**186,661**	**185,422**	**183,031**	**-0.1%**

Sources: [a] USCB 2010; [b] Cornell University 2009.

Region C

Table 2.52 provides the 1990, 2000 and 2010 population for Region C and for Cattaraugus and Chautauqua Counties. The population of Region C is 215,222 persons (USCB 2010), with an average population density of 90.7 persons per square mile. Between 2000 and 2010, the region lost population at an average annual rate of 0.4%. This rate was higher than the rate at which the region lost population between 1990 and 2000 (0.1% per year). Since 1990 the population of Region C has decreased by 10,907, or 4.8%.

Table 2.52 - Region C: Historical and Current Population - 1990, 2000, 2010 (New August 2011)

	1990	2000	2010
Region C			
Population	226,129	223,705	215,222
Percent Change	--	-1.1%	-3.8%
Average Annual Growth Rate	--	-0.1%	-0.4%
Average Population Density	95.3	94.3	90.7
Cattaraugus County			
Population	84,234	83,955	80,317
Percent Change	--	-0.3%	-4.3%
Average Annual Growth Rate	--	< 0.0%	-0.4
Average Population Density	64.3	64.1	61.3
Chautauqua County			
Population	141,895	139,750	134,905
Percent Change	--	-1.5%	-3.5%
Average Annual Growth Rate	--	-0.2%	-0.4%
Average Population Density	133.6	131.6	127.0

Source: USCB 1990a, 2000b, and 2010.

The largest population centers in Region C are the City of Jamestown (31,146 persons), City of Olean (14,452 persons), City of Dunkirk (12,563 persons), and Village of Fredonia (11,230 persons).

Region C's population has continually decreased during the past 20 years, though the rate of decline was faster from 2000 to 2010 than it was from 1990 to 2000. As shown in Table 2.53, the population of Region C is projected to continue to decrease through 2030. The population of Region C is projected to decrease at an average annual rate of 0.6% between 2015 and 2030. By 2030, Region C's population is projected to be 188,752 people, which would be a decrease of 12% from the 2010 census population.

Table 2.53 - Region C: Population Projections, 2015 to 2030 (New August 2011)

County/ Region	Population 2010[a] (actual)	Population 2015[b] (projected)	Population 2020[b] (projected)	Population 2025[b] (projected)	Population 2030[b] (projected)	Average Annual Growth Rate 2015-2030
Cattaraugus	80,317	77,870	75,651	73,048	70,075	-0.7%
Chautauqua	134,905	129,596	126,521	122,906	118,677	-0.6%
Region C Total	**215,222**	**207,466**	**202,172**	**195,954**	**188,752**	**-0.6%**

Source:
[a] USCB 2010.
[b] Cornell University 2009.

2.4.11.3 Housing

New York State

The total number of housing units in New York State in 2010 was 8.1 million. The total number of housing units has been growing over the past two decades; however, with the advent of the recent housing market crisis and recession, the rate of growth has slowed in the past few years. According to the U.S. Census Bureau, in 1990 there were a total of 7.2 million housing units in New York State. By 2000, the total number of housing units increased by 6.3% to approximately 7.7 million. Between 2000 and 2010, the total number of housing units increased by 5.6% (see Table 2.54) (USCB 1990b, 2000c, 2010).

Table 2.54 - New York State: Total Housing Units - 1990, 2000, 2010 (New August 2011)

Year	Total Housing Units	Percent Change
2010	8,108,103	5.6
2000	7,679,307	6.3
1990	7,226,891	--

Source: USCB 1990b, 2000c, and 2010.

Nearly half of all housing units in New York State are single-family units. In 2009 an estimated 3.7 million units, or 47.0% of all housing units in the state, were single-family units. Multi-family units, i.e., structures that have three or more units in them, accounted for 39.5% of the total housing units (see Table 2.55) (USCB 2009c).

Table 2.55 - New York State: Type of Housing Units, 2009[1] (New August 2011)

Type of Structure	Total Number of Units	% of Total
Single Family	3,735,364	47.0
Duplex	866,157	10.9
Multi-family	3,142,770	39.5
Mobile Home	202,773	2.6
Other	2,971	<0.1
Total	**7,905,035**	**100**

Source: USCB 2009c.

[1] Data from the *2010 Census of Population and Housing* on housing units by type of structure had not been released at the time of this report; therefore, estimated 2009 data from the 2005-2009 *American Community Survey* estimates is included herein.

Table 2.56 provides the number of sales and annual median sale price of single family homes sold in New York State over the past three years. The number of annual sales has declined over the

past three years, while the median sales price has fluctuated. In 2008 the median sales price for single-family homes was $210,000. During the height of the housing market crisis in 2009, the median sales price fell to $195,000. By 2010 prices in the statewide housing market had recovered, and median sales prices rose to $215,000 (NYS Association of Realtors 2011a, 2011b). Although the statewide housing market statistics have improved over the last year, housing is intrinsically a local or regional market; many areas of New York State are still experiencing downward pressures on house prices.

Table 2.56 - New York State: Number of Sales and Annual Median Sale Price of Single-Family Homes Sold, 2008-2010 (New August 2011)

	2008	**2009**	**2010**
Number of Sales	80,521	78,327	74,718
Median Sale Price	$210,000	$195,000	$215,000

Source: NYS Association of Realtors 2011a, 2011b.

In 2010, New York State had approximately 3.9 million owner-occupied housing units and 3.4 million renter-occupied housing units (USCB 2010).

The homeowner vacancy rate was 1.9% and the rental vacancy rate was 5.5% (USCB 2010) (see Table 2.57).

Table 2.57 - New York State: Housing Characteristics, 2010 (New August 2011)

	Housing Units
Occupied	7,317,755
Owner Occupied	3,897,837
Renter Occupied	3,419,918
Vacant	790,348
For Rent	200,039
Rented, Not Occupied	12,786
For Sale Only	77,225
Sold, Not Occupied	21,027
For Seasonal, Recreational, or Occasional Use	289,301
All Other Vacant	189,970
Total	**8,108,103**
Homeowner Vacancy Rate	1.9%
Rental Vacancy Rate	5.5%

Source: USCB 2010.

Region A

According to the U.S. Census Bureau, the housing market in Region A has experienced little growth over the past two decades. As shown in Table 2.58, the region experienced an increase of 1.7% in the total number of housing units from 1990 to 2000, and a 2.1% increase from 2000 to 2010 (USCB 1990b, 2000c, 2010).

Table 2.58 - Region A: Total Housing Units - 1990, 2000, 2010 (New August 2011)

	Total Housing Units (1990)	**Total Housing Units (2000)**	**Total Housing Units (2010)**	**Percent Change (1990-2000)**	**Percent Change (2000-2010)**
Region A	145,513	147,972	151,135	1.7%	2.1%
Broome County	87,969	88,817	90,563	1.0%	2.0%
Chemung County	37,290	37,745	38,369	1.2%	1.7%
Tioga County	20,254	21,410	22,203	5.7%	3.7%

Source: USCB 1990b, 2000c, 2010.

A majority of housing units in Region A are single-family units. In 2009 an estimated 96,956 units, or 65.0% of all housing units in the region, were single-family units. Multi-family units, i.e., structures that contained three or more housing units, accounted for 17.0% of the total housing units (see Table 2.59).

Table 2.59 - Region A: Total Housing Units by Type of Structure, 2009[1] (New August 2011)

	Number of Units	**% of Total**
Region A		
Single Family	96,956	65.0
Duplex	15,901	10.8
Multi-family	25,389	17.0
Mobile Home	10,756	7.2
Other	64	<0.1
	149,066	**100**
Broome County		
Single Family	56,225	63.1
Duplex	10,436	11.7
Multi-family	17,646	19.8
Mobile Home	4,795	5.4
Other	15	<0.1
	89,117	**100**

	Number of Units	% of Total
Chemung County		
Single Family	25,739	67.5
Duplex	4,291	11.3
Multi-family	5,749	15.1
Mobile Home	2,325	6.1
Other	12	<0.1
	38,116	**100**
Tioga County		
Single Family	14,992	68.7
Duplex	1,174	5.4
Multi-family	1,994	9.1
Mobile Home	3,636	16.7
Other	37	0.1
Total	**21,833**	**100**

Source: USCB 2009c.

1 Data from the *2010 Census of Population and Housing* on housing units by type of structure had not been released at the time of this report; therefore, estimated 2009 data from the 2005-2009 *American Community Survey* are provided herein.

Table 2.60 provides the number of sales and annual median sale price of single family homes sold in Region A over the past three years (New York State Association of Realtors 2011a, 2011b).

Table 2.60 - Region A: Number of Sales and Annual Median Sale Price of Single-Family Homes Sold, 2008-2010 (New August 2011)

	2008		2009		2010	
	Number of Sales	**Median Sale Price**	**Number of Sales**	**Median Sales Price**	**Number of Sales**	**Median Sales Price**
Broome County	1,412	$109,438	1,287	$115,000	1,193	$106,000
Chemung County	629	$85,000	593	$86,000	638	$100,000
Tioga County	275	$136,170	304	$120,000	227	$122,500
Region A	2,316	NA	2,184	NA	2,058	NA

Source: NYS Association of Realtors 2011a, 2011b.
NA = Not available.

In 2010, Region A had approximately 93,074 owner-occupied housing units and 44,905 renter-occupied housing units. The homeowner vacancy rate was 1.1%, and the rental vacancy rate was 7.8% (see Table 2.61) (USCB 2010).

Table 2.61 - Region A: Housing Characteristics, 2010 (New August 2011)

	Housing Units			
	Region A	**Broome County**	**Chemung County**	**Tioga County**
Occupied	137,979	82,167	35,462	20,350
Owner Occupied	93,074	53,260	24,011	15,803
Renter Occupied	44,905	28,907	11,451	4,547
Vacant	13,156	8,396	2,907	1,853
For Rent	3,824	2,522	917	385
Rented, Not Occupied	226	143	56	27
For Sale Only	1,516	956	377	183
Sold, Not Occupied	471	226	151	94
For Seasonal, Recreational, or Occasional Use	2,774	1,843	376	555
All Other Vacant	4,345	2,706	1,030	609
Total	**151,135**	**90,563**	**38,369**	**22,203**
Homeowner Vacancy Rate	1.1%	1.8%	1.5%	1.1%
Rental Vacancy Rate	7.8%	8.0%	7.4%	7.8%

Source: USCB 2010.

The *2010 Census of Population and Housing* identified 2,774 housing units in Region A that are considered seasonal, recreational, or occasional use. In addition to the permanent housing discussed above, there are also numerous short-term accommodations including hotels, motels, inns, and campgrounds available in the area. Table 2.62 lists the numbers of hotels/motels available in Region A that were registered with the I Love New York Tourism Agency. As of 2011 there were 40 hotels/motels with approximately 3,110 rooms in Region A.

Table 2.62 - Region A: Short-Term Accommodations (Hotels/Motels), 2011 (New August 2011)

	Total Hotels/Motels	**Total Rooms**
Broome County	27	2,202
Chemung County	9	676
Tioga County	4	232
Region A	**40**	**3,110**

Source: Official New York State Tourism Site (ILOVENY) 2011.

Region B

According to the U.S. Census Bureau, the rate of growth of the housing supply in Region B has increased since 1990. The total number of housing units in the region grew from 95,560 in 1990 to 102,163 in 2000, an increase of 6.9%. Between 2000 and 2010, the total number of housing units increased to 111,185, an increase of 8.8%. (see Table 2.63) (USCB 1990b, 2000c, 2010).

Table 2.63 - Region B: Total Housing Units - 1990, 2000, 2010 (New August 2011)

	Total Housing Units (1990)	**Total Housing Units (2000)**	**Total Housing Units (2010)**	**Percent Change (1990-2000)**	**Percent Change (2000-2010)**
Delaware County	27,361	28,952	31,222	5.8%	7.8%
Otsego County	26,385	28,481	30,777	7.9%	8.1%
Sullivan County	41,814	44,730	49,186	7.0%	10.0%
Region B	**95,560**	**102,163**	**111,185**	**6.9%**	**8.8%**

Source: USCB 1990b, 2000c, 2010.

A majority of housing units in Region B are single-family units. In 2009 an estimated 76,883 units, or 70.7% of all housing units in the region, were single-family units. Mobile homes accounted for 12.7% of the total housing units (see Table 2.64).

Table 2.64 - Region B: Total Housing Units by Type of Structure 2009[1] (New August 2011)

	Number of Units	**% of Total**
Region B		
Single Family	76,883	70.7
Duplex	6,025	5.5
Multi-family	12,097	11.1
Mobile Home	13,731	12.7
Other	6	<0.1
Total	**108,742**	**100**
Delaware		
Single Family	21,876	73.6
Duplex	1,502	5.0
Multi-family	2,400	8.1
Mobile Home	3,949	13.3
Other	0	0
Total	**29,727**	**100**
Otsego		
Single Family	20,576	67.1
Duplex	1,791	5.9

	Number of Units	% of Total
Multi-family	3,868	12.6
Mobile Home	4,405	14.4
Other	6	<0.1
Total	**30,646**	**100**
Sullivan		
Single Family	34,431	71.2
Duplex	2,732	5.6
Multi-family	5,829	12.1
Mobile Home	5,377	11.1
Other	0	0
Total	**48,369**	**100**

Source: USCB 2009c.

[1] Data from the 2010 Census of Population and Housing on housing units by type of structure had not been released at the time of this report; therefore, estimated 2009 data from the 2005-2009 American Community Survey are provided herein.

As shown in Table 2.65, the housing market in Region B experienced a general decline in total sales and price in the single-family home market from 2008 to 2010. In the region as a whole, the number of single-family homes sold each year from 2008 to 2010 declined by 8.7%, from 785 homes in 2008 to 717 homes in 2010.

Median sale prices in the region experienced similar trends. From 2008 to 2010, the median sale price of single-family homes in Sullivan and Otsego Counties decreased by 16.4% and 8.8%, respectively. In contrast, the median sale price of homes in Delaware County remained relatively constant from 2008 to 2010 (see Table 2.65).

Table 2.65- Region B: Number of Sales and Annual Median Sale Price of Single-Family Homes Sold, 2008-2010 (New August 2011)

	2008		2009		2010	
	Number of Sales	Median Sale Price	Number of Sales	Median Sales Price	Number of Sales	Median Sales Price
Delaware County	160	$109,250	171	$110,000	149	$110,000
Otsego County	309	$131,000	304	$126,523	319	$119,500
Sullivan County	316	$149,450	269	$125,000	249	$125,000
Region B	785	NA	744	NA	717	NA

Source: NYS Association of Realtors 2011a, 2011b.
NA = Not available.

In 2010, Region B had approximately 52,860 owner-occupied housing units and 21,797 renter-occupied housing units. The homeowner vacancy rate was 2.6%, and the rental vacancy rate was 10.6% (USCB 2010).

There were 2,604 units for rent, 1,989 units for sale, and 27,240 units for seasonal, recreational, or occasional use in the area (see Table 2.66). The percentage of vacant seasonal, recreational, or occasional use units was very high, largely due to the region's proximity to the Catskill Mountains (USCB 2010).

Table 2.66 - Region B: Housing Characteristics, 2010 (New August 2011)

	Housing Units			
	Region B	**Delaware County**	**Otsego County**	**Sullivan County**
Occupied	74,657	19,898	24,620	30,139
Owner Occupied	52,860	14,768	17,885	20,207
Renter Occupied	21,797	5,130	6,735	9,932
Vacant	36,528	11,324	6,157	19,047
For Rent	2,604	565	615	1,424
Rented, Not Occupied	157	36	45	76
For Sale Only	1,989	446	514	1,029
Sold, Not Occupied	461	117	127	217
For Seasonal, Recreational, or Occasional Use	27,240	9,276	3,621	14,343
All Other Vacant	4,077	884	1,235	1,958
Total	**111,185**	**31,222**	**30,777**	**49,186**
Homeowner Vacancy Rate	2.6%	2.9%	2.8%	4.8%
Rental Vacancy Rate	10.6%	9.9%	8.3%	12.5%

Source: USCB 2010.

In addition to the permanent housing discussed above, there are also numerous short-term accommodations including hotels, motels, inns, and campgrounds available in the area. Table 2.67 lists the number of hotels/motels available in Region B that was registered with the I Love New York Tourism Agency. As of 2011 there were 78 hotels/motels with approximately 3,705 rooms in Region B (see Table 2.67).

Table 2.67 - Region B: Short-Term Accommodations (Hotels/Motels) (New August 2011)

	Total Hotels/Motels	**Total Rooms**
Delaware County	27	1,123
Otsego County	34	1,373
Sullivan County	17	1,209
Region B	**78**	**3,705**

Source: Official New York State Tourism Site (ILOVENY) 2011.

Region C

In 2010, Region C had a total of 108,031 housing units. The total number of housing units increased by 8.1% between 1990 and 2000, and by 3.2% between 2000 and 2010 (see Table 2.68) (USCB 1990b, 2000c, 2010). Approximately 62% of the housing units are located in Chautauqua County, and 38% are located in Cattaraugus County.

Table 2.68 - Region C: Total Housing Units - 1990, 2000, 2010 (New August 2011)

	Total Housing Units (1990)	**Total Housing Units (2000)**	**Total Housing Units (2010)**	**Percent Change (1990-2000)**	**Percent Change (2000-2010)**
Cattaraugus County	36,839	39,839	41,111	8.1%	3.2%
Chautauqua County	62,682	64,900	66,920	3.5%	3.1%
Region C	99,521	104,739	108,031	5.2%	3.1%

Source: USCB 1990b, 2000c, 2010.

Most of the housing units in Region C are single-family units. In 2009 an estimated 106,519 units, or 68.7% of all housing units in the region, were single-family units (see Table 2.69)

Table 2.69 - Region C: Total Housing Units by Type of Structure, 2009[1] (New August 2011)

	Number of Units	**% of Total**
Region C		
Single Family	73,183	68.7
Duplex	10,802	10.1
Multi-family	12,432	11.7
Mobile Home	10,090	9.5
Other	12	<0.1
Total	**106,519**	**100**
Cattaraugus		
Single Family	28,451	70.1
Duplex	2,850	7.0
Multi-family	3,797	9.3
Mobile Home	5,502	13.6
Other	12	<0.1
Total	**40,612**	**100**
Chautauqua		
Single Family	44,732	67.9
Duplex	7,952	12.0
Multi-family	8,635	13.1
Mobile Home	4,588	7.0
Other	0	0
Total	**65,907**	**100**

Source: USCB 2009c.

[1] Data from the *2010 Census of Population and Housing* on housing units by type of structure had not been released at the time of this report; therefore, estimated 2009 data from the 2005-2009 *American Community Survey* are provided herein.

As shown on Table 2.70, the market for single-family homes in Region C declined over the past three years. In the region as a whole, the number of single-family homes sold each year from 2008 to 2010 declined by 14.1%, from 1,492 homes in 2008 to 1,281 homes in 2010 (NYS Association of Realtors 2011a, 2011b).

Table 2.70 - Region C: Number of Sales and Annual Median Sale Price of Single-Family Homes Sold, 2008-2010 (New August 2011)

	2008		2009		2010	
	Number of Sales	**Median Sale Price**	**Number of Sales**	**Median Sales Price**	**Number of Sales**	**Median Sales Price**
Cattaraugus County	577	$69,000	501	$70,000	434	$73,000
Chautauqua County	915	$75,000	843	$74,521	847	$80,000
Region C	1,492	NA	1,344	NA	1,281	NA

Source: NYS Association of Realtors 2011a, 2011b.
NA = Not available.

In 2010 Region C had approximately 60,182 owner-occupied housing units and 26,325 renter-occupied housing units. The homeowner vacancy rate was 1.4%, and the rental vacancy rate was 9.0% (see Table 2.71) (USCB 2010).

Table 2.71 - Region C: Housing Characteristics, 2010 (New August 2011)

	Region C	**Cattaraugus County**	**Chautauqua County**
Occupied	86,507	32,263	54,244
Owner Occupied	60,182	23,306	36,876
Renter Occupied	26,325	8,857	17,368
Vacant	21,524	8,848	12,676
For Rent	2,624	748	1,876
Rented, Not Occupied	178	82	96
For Sale Only	1,278	483	795
Sold, Not Occupied	426	157	269
For Seasonal, Recreational, or Occasional Use	13,308	6,035	7,573
All Other Vacant	3,410	1,343	2,067
Total	108,031	41,111	66,920
Homeowner Vacancy Rate	1.4%	2.0%	2.1%
Rental Vacancy Rate	9.0%	7.6%	9.7%

Source: USCB 2010.

There were 2,624 units for rent, 1,278 units for sale, and 13,608 units for seasonal, recreational, or occasional use in the area. The percentage of vacant seasonal, recreational, or occasional use units was very high, largely due to the cottages around Lake Chautauqua, Chautauqua Institute, and other natural areas in these counties (USCB 2010).

In addition to the permanent housing discussed above, there are also numerous short-term accommodations including hotels, motels, inns, and campgrounds available in the area. Table 2.72 lists the number of hotels/motels available in Region C that was registered with the I Love New York Tourism Agency. As of 2011 there were 41 hotels/motels with approximately 1,987 rooms in Region C (see Table 2.72).

Table 2.72 - Region C: Short-Term Accommodations (Hotels/Motels) (New August 2011)

	Total Hotels/Motels	**Total Rooms**
Cattaraugus County	17	634
Chautauqua County	24	1,353
Region C	**41**	**1,987**

Source: Official New York State Tourism Site (ILOVENY) 2011.

2.4.11.4 Government Revenues and Expenditures

New York State

Table 2.73 lists the main sources of tax revenues for New York State. For fiscal year (FY) ending March 31, 2010, revenues collected in New York State totaled approximately $55 billion. Revenue from personal income taxes is the largest source of tax revenue for the state, accounting for approximately 63% of the total revenue (New York State Department of Taxation and Finance [NYSDTF] 2010a, 2010b).

Table 2.73 - New York State Revenues Collected for FY Ending March 31, 2010 (New August 2011)

	Personal Income Taxes	**Corporation and Business Taxes**	**Sales and Excise Taxes and User Fees**	**Property Transfers**	**Other Taxes and Fees**	**Total Revenues**
Total Revenues ($ billions)	$34.8	$6.6	$12.2	$1.4	$0.2	$55.2
Percent of Total	63.0	12.0	22.1	2.5	0.4	100.0

Source: NYSDTF 2010a, 2010b.
Totals may not equal sum of components due to rounding.

Currently, no specific state tax is levied on the extraction of natural gas in New York State; however, the state government receives revenues from the natural gas industry and from natural gas development primarily through income and sales taxes. The state assesses personal income tax on wages earned by workers in the industry, and income received by individuals as royalty payments and lease payments from natural gas operators. Further, the state also collects revenue from sales taxes receipts from the purchase of non-exempt materials and equipment needed to construct and operate natural gas wells. In some cases, the state may receive revenue from corporate and business taxes assessed on the corporate income of natural gas operators, though these taxes are subject to various exemptions and incentives that reduce the amount of revenue that the state is able to collect from the natural gas industry. In addition, New York State receives revenues from leases for oil and natural gas development on state lands. Lease revenues are acquired through delay rentals; bonus bids; royalties; and storage fees. Delay rentals are the annual fees that oil and natural gas developers pay to hold a leased property before development occurs. Bonus bids are additional fees above the delay rental fee for a specific tract. All bonus bids are subject to a sealed competitive bidding process. Once the gas well is developed, the delay rental payments are waived and the developer is assessed royalty fees of 12.5% of gross revenues. Storage fees are fees that are levied on the operators of underground natural gas storage facilities. A summary of the acreage and number of leases on state lands is provided in Table 2.74. Table 2.75 provides a summary of state revenues received between 2000 and 2010 from oil and gas lease payments.

Table 2.74 - New York State: Number of Leases and Acreage of State Land Leased for Oil and Natural Gas Development, 2010 (New August 2011)

County	Acreage of State Land Leased				Number of Leases			
	Rental	Royalty	Storage	Total	Rental	Royalty	Storage	Total
Allegany		126		126		1		1
Broome	512			512	1			1
Cattaraugus		62	9,981	10,043		2	8	10
Cayuga		62		62		4		4
Chautauqua		15,715		15,715		29		29
Chemung	730	667		1,397	3	10		13
Cortland	7,791			7,791	4			4
Erie		10	255	265		2	2	4
Ontario			55	55			1	1
Schuyler	2,416	10,019	1	12,436	1	6	1	8
Seneca		17		17		1		1
Steuben	685	5,859	1,620	8,164	1	8	2	11
Tioga	6,179			6,179	6			6
Tompkins	915			915	1			1
Total	**19,228**	**32,537**	**11,912**	**63,677**	**17**	**63**	**14**	**94**

Source: NYSDEC 2010.

Table 2.75 - 2000-2010 Leasing Revenue by Payment Type for New York State (New August 2011)

Year	Bonus Bids	Delay Rentals	Royalties	Storage Fees	Yearly Total
2000	-	$42,280	$75,327	$9,781	$127,388
2001	-	$118,732	$150,922	$178,128	$447,782
2002	-	$79,435	$96,620	$73,617	$249,672
2003	$4,583,239	$16,486	$609,821	$117,381	$5,326,927
2004	-	$130,746	$525,050	$109,986	$765,782
2005	-	$80,534	$3,235,206	$123,930	$3,439,670
2006	-	$75,305	$3,096,620	$125,007	$3,296,932
2007	$9,001,335	$166,868	$2,466,312	$133,298	$11,767,813
2008	-	$97,269	$1,866,519	$211,927	$2,175,715
2009	-	$96,136	$637,254	$50,960	$784,350
2010	$2,922	$96,377	$581,824	$65,010	$746,133

Source: NYSDEC 2010.

In New York State, local government entities have taxing authority for real property tax purposes.

However, the New York State Department of Taxation and Finance provides a uniform, statewide method of valuing natural-gas-producing properties for real property tax purposes. Valuations of natural-gas-producing properties are based on a "unit of production" value - a dollar amount per Mcf of gas produced. The total valuation is then equalized across four natural gas producing regions within the state, and then taxed at the local millage rate, similar to any other real property within the local jurisdiction.

Spending on community services is generally divided between the state and local governments (i.e., counties, municipalities, fire districts, and school districts). For public safety, New York State funds state troopers, counties fund county sheriffs, and municipalities commonly fund local police services. Emergency services such as fire protection/EMT are largely volunteer efforts in smaller towns, with some financial support received from smaller cities, suburban and rural towns, and villages. Major cities generally support their own fire departments, which generally have their own EMT operation.

Roadways are also supported by various levels of government. New York State provides funding for state and local highways, the operation of which is the responsibility of the NYSDOT as well as the New York State Thruway Authority. Counties finance county highways, while municipalities generally provide the funds to administer and maintain local roadways.

In regards to education, New York State financially supports the State University of New York (SUNY), a system of higher education institutions. Funding for K-12 education is generally provided by local school districts, which in turn receive revenues from a variety of sources, including federal aid, state aid, and real property taxes, among others.

Recreation services, including public parks, are another expenditure in which both state and local governments contribute. New York State provides funding to OPRHP, which operates recreational facilities at the state level, including the state park system. County governments generally provide funds for recreational facilities in towns and villages, while cities and larger suburban areas generally support their own recreational services.

Health, including Medicaid, is an expenditure that is largely carried by the state. Medicaid is a joint federal-state program. However, counties and major cities in New York State also contribute funds. Counties and local governments also have miscellaneous health care costs, including public health administration, public health services, mental health services, environmental services, and public health facilities, among others.

Expenditures for water and waste water treatment are generally made by counties and local municipalities.

Region A

Table 2.76 lists the main sources of public revenues for Region A. Revenues collected in Region A totaled approximately $736 million for the fiscal year ending December 31, 2009. The majority of revenues were derived from local sources. Local revenue, including ad valorem (real and personal property) tax receipts and services, accounted for approximately 67.5% of total revenues in Region A (NYS Office of the State Comptroller 2010a).

Table 2.76 - Region A: Total Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Taxes[1] (% of total)	**Services[2] (% of total)**	**Subtotal Local Revenue (% of total)**	**State/ Federal Aid (% of total)**	**Subtotal Local// (% of total)**	**Other Sources[3] (% of total)**	**Total Revenue[4]**
Broome County	$169.4 (37.0)	$139.6 (30.4)	$309.0 (67.4)	$127.5 (27.8)	$436.5 (95.2)	$22.1 (4.8)	$458.6
Chemung County	$80.6 (42.0)	$47.3 (24.7)	$127.9 (66.7)	$54.8 (28.6)	$182.7 (95.3)	$9.1 (4.7)	$191.8
Tioga County	$39.4 (46.2)	$20.6 (24.1)	$60.0 (70.2)	$20.4 (23.9)	$80.4 (94.0)	$5.1 (6.0)	$85.5
Region A	$289.4 (39.4)	$207.5 (28.2)	$496.9 (67.5)	$202.7 (27.5)	$699.6 (95.1)	$36.3 (4.9)	$735.9

Source: NYS Office of the State Comptroller 2010a.

1 Taxes include real property taxes and assessments, other real property tax items, sales and use taxes, and other non-property taxes.

2 Services include charges for services, charges to other governments, use and sale of property, and other local revenues.

3 Other revenues include proceeds of debt and all other sources of revenue.

4 Totals may not equal sum of components due to rounding.

As shown in Table 2.77, the total local tax revenue collected in Region A during the FY ending on December 31, 2009, was approximately $289.4 million. Of the total tax collected, 59.8% was derived from sales tax and distribution. Real property taxes, special assessments, and other real property tax items accounted for about 39.1% of the total local revenue (NYS Office of the State Comptroller 2010a).

Table 2.77 - Region A: Local Tax Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Real Property Taxes (% of total)	Special Assessments (% of total)	Other Real Property Tax Items[1] (% of total)	Sales Tax and Distribution (% of total)	Miscellaneous Use Taxes (% of total)	Other Non-Property Taxes[2] (% of total)	Total Tax Collection[3]
Broome County	$59.1 (34.9)	$0 (0)	$4.0 (2.4)	$104.1 (61.4)	$1.5 (0.9)	$0.7 (0.4)	$169.4
Chemung County	$26.8 (33.3)	$0 (0)	$1.9 (2.4)	$51.2 (63.5)	$0.6 (0.7)	$0.1 (0.1)	$80.6
Tioga County	$19.2 (48.7)	$0 (0)	$2.2 (5.6)	$17.7 (44.9)	$0.1 (0.3)	$0.2 (0.5)	$39.4
Region A	$105.1 (36.3)	$0 (0)	$8.1 (2.8)	$173.0 (59.8)	$2.2 (0.7)	$1.0 (0.4)	$289.4

Source: NYS Office of the State Comptroller 2010a.

1 Other real property tax items include STAR payments, payments in lieu of taxes, interest penalties, gain from sale of tax acquired property, and miscellaneous tax items.

2 Other non-property taxes include franchises, emergency telephone system surcharges, city income taxes, and other miscellaneous non-property taxes.

3 Totals may not equal sum of components due to rounding.

The production value (e.g., gas economic profile), state equalization rate, and millage rate for gas-producing properties in Region A are shown in Table 2.78. Broome, Chemung, and Tioga Counties are within the Medina Region 3, natural-gas-producing region designated by New York State. The final gas unit of production value for gas-producing properties within Medina Region 3 was $11.19 in 2010 (NYSDTF 2011). The overall full-value millage rates for Broome, Chemung, and Tioga Counties were 35.50, 34.30 and 30.80, respectively. These rates have already been equalized and include the rates of all taxing districts in the county, including county, town, village, school district, and other special district rates.

Table 2.78 - Gas Economic Profile for Medina Region 3 (New August 2011)

	2010 Final Gas Unit of Production Value[a]	Millage Rate[b] (2010)
Broome County	$11.19	35.50
Chemung County	$11.19	34.30
Tioga County	$11.19	30.80

Sources:

a NYSDTF 2011.

b NYS Office of the State Comptroller 2010b. Millage rates represent the "overall full-value tax rate" and include the rates of all taxing districts in the county, including county, town, village, school district, and special districts rates.

Table 2.79 presents local government expenditures for Region A during the FY ending December 31, 2009. Social services combined to create the largest single expenditure in each of the counties of Region A. Approximately 28.7% of the counties' collective operating and capital budgets were spent on social services during the FY ending December 31, 2009. Expenditure categories within social services include social service administration, financial assistance, Medicaid, non-Medicaid medical assistance, housing assistance, employment services, youth services, public facilities, and miscellaneous social services. Other major expenditures in Region A included general government (20.5%), employee benefits (15.3%), and health (9.9%). Public safety accounted for approximately 7.0% of total expenditures in Region A, including $15,299,556 for police and $118,376 for fire protection. No county in Region A spent any monies on emergency response. Broome and Chemung Counties did not financially support any fire protection services (NYS Office of the State Comptroller 2010a).

Table 2.79 - Region A: Expenditures for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Broome County		**Chemung County**		**Tioga County**		**Region A**	
	Total $	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**
General Government	$91,817,010	20.4	$33,090,334	17.8	$21,682,356	27.0	$146,589,700	20.5
Education	$20,406,276	4.5	$4,412,651	2.4	$5,191,138	6.5	$30,010,065	4.2
Public Safety	$30,483,583	6.8	$12,944,032	7.0	$6,467,954	8.1	$49,895,569	7.0
Health	$39,151,049	8.7	$24,028,632	12.9	$7,398,260	9.2	$70,577,941	9.9
Transportation	$22,685,968	5.1	$14,625,859	7.9	$6,181,134	7.7	$43,492,961	6.1
Social Services	$122,931,621	27.4	$61,987,864	33.4	$20,346,458	25.4	$205,265,943	28.7
Economic Development	$6,005,330	1.3	$60,000	<0.1	$636,502	0.8	$6,701,832	0.9
Culture and Recreation	$10,186,350	2.3	$2,349,947	1.3	$232,827	0.3	$12,769,124	1.8
Community Services	$6,768,148	1.5	$2,978,999	1.6	$569,025	0.7	$10,316,172	1.4
Utilities	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Sanitation	$954,025	0.2	$5,780,216	3.1	$1,176,043	1.5	$7,910,284	1.1
Employee Benefits	$82,228,270	18.3	$17,926,465	9.6	$9,460,820	11.8	$109,615,555	15.3
Debt Service	$15,410,760	3.4	$5,620,336	3.0	$862,138	1.1	$21,893,234	3.1
Total Expenditures	$449,028,390	100.0	$185,805,335	100.0	$80,204,655	100.0	$715,038,380	100.0

Source: NYS Office of the State Comptroller 2010a.

Region B

Table 2.80 lists 2.4 the main sources of county government revenues for Region B. Revenues collected in Region B totaled approximately $429.0 million for the fiscal year ending December 31, 2009. Most of the revenues were derived from local sources. Local revenue, including ad valorem (real and personal property) tax receipts and services, accounted for approximately 65.6% of total revenues in Region B (NYS Office of the State Comptroller 2010a).

Table 2.80 - Region B: Total Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Taxes[1] (% of total)	**Services[2] (% of total)**	**Subtotal Local Revenue (% of total)**	**State/ Federal Aid (% of total)**	**Subtotal Local// (% of total)**	**Other Sources[3] (% of total)**	**Total Revenue[4]**
Delaware County	$43.1 (37.6)	$21.1 (18.4)	$64.2 (56.0)	$33.0 (28.8)	$97.1 (84.8)	$17.4 (15.2)	$114.5
Otsego County	$44.7 (41.6)	$30.7 (28.5)	$75.4 (70.1)	$25.2 (23.4)	$100.6 (93.5)	$7.0 (6.5)	$107.6
Sullivan County	$84.2 (40.7)	$57.5 (27.8)	$141.7 (68.5)	$44.2 (21.4)	$186.0 (89.9)	$20.9 (10.1)	$206.9
Region B	$172.0 (40.1)	$109.3 (25.5)	$281.3 (65.6)	$102.4 (23.9)	$383.7 (89.4)	$45.3 (10.6)	$429.0

Source: NYS Office of the State Comptroller 2010a.

1 Taxes include real property taxes and assessments, other real property tax items, sales and use taxes, and other non-property taxes.
2 Services includes charges for services, charges to other governments, use and sale of property, and other local revenues.
3 Other revenues include proceeds of debt and all other sources of revenue.
4 Totals may not equal sum of components due to rounding.

As shown in Table 2.81, the total local tax revenue in Region B during the fiscal year ending on December 31, 2009, was approximately $173.7 million. Of the total tax collected, 49.2% was derived from taxes levied on real property, special assessments, and other real property tax items. Sales tax and distribution accounted for approximately 48.4% of the total (NYS Office of the State Comptroller 2010a).

Table 2.81 - Region B: Local Tax Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Real Property Taxes (% of total)	Special Assessments (% of total)	Other Real Property Tax Items[1] (% of total)	Sales Tax and Distribution (% of total)	Miscellaneous Use Taxes (% of total)	Other Non-Property Taxes[2] (% of total)	Total Revenue
Delaware County	$23.4 (54.2)	$0 (0)	$1.7 (3.9)	$17.9 (41.4)	$0 (0)	$0.2 (0.5)	$43.2
Otsego County	$9.5 (20.5)	$1.1 (2.4)	$1.4 (3.0)	$33.1 (71.3)	$1.1 (2.4)	$0.2 (0.4)	$46.4
Sullivan County	$42.1 (50.1)	$0 (0)	$6.3 (7.5)	$33.1 (39.4)	$1.1 (1.3)	$1.5 (1.8)	$84.1
Region B	$75.0 (43.2)	$1.1 (0.6)	$9.4 (5.4)	$84.1 (48.4)	$2.2 (1.3)	$1.9 (1.1)	$173.7

Source: NYS Office of the State Comptroller 2010a.

1 Other real property tax items include STAR payments, payments in lieu of taxes, interest penalties, gain from sale of tax acquired property, and miscellaneous tax items.

2 Other non-property taxes include franchises, emergency telephone system surcharges, city income taxes, and other miscellaneous non-property taxes.

3 Totals may not equal sum of components due to rounding.

Delaware, Otsego, and Sullivan Counties are within Medina Region 4, natural-gas-producing region designated by New York State. The final gas unit of production value for gas-producing properties within the Medina Region 4 was $11.19 in 2010; the 2011 tentative gas unit of production value is $11.32 (NYSDTF 2011). The 2010 overall full-value millage rates for Delaware, Otsego, and Sullivan Counties were 21.20, 19.60 and 26.20, respectively (see Table 2.82). These rates have already been equalized and include the rates of all taxing districts in the county, including county, town, village, school district, and other special district rates.

Table 2.82 - Gas Economic Profile for Medina Region 4 and State Equalization Rates and Millage Rates for Region B (New August 2011)

	Final Gas Unit of Production Value (2010)[a]	Millage Rate[b] (2010)
Delaware County	$11.19	21.20
Otsego County	$11.19	19.60
Sullivan County	$11.19	26.20

Sources:

a NYSDTF 2011.

b NYS Office of the State Comptroller 2010b. Millage rates represent the "overall full-value tax rate" and include the rates of all taxing districts in the county, including county, town, village, school district, and special districts rates.

Table 2.83 presents local government expenditures for Region B during the FY ending December 31, 2009. Social services combined to create the largest single expenditure in each of the counties in Region B. Approximately 30% of the counties' collective operating and capital budgets were spent on social services during the FY ending December 31, 2009. Expenditure categories within social services include social service administration, financial assistance, Medicaid, non-Medicaid medical assistance, housing assistance, employment services, youth services, public facilities, and miscellaneous social services. Other major expenditures in Region B included employee benefits (14.5%), general government (12.4%), and transportation (12.3%). Public safety accounted for approximately 7.7% of total expenditures in Region B, including $9,103,208 for police and $70,719 for fire protection. No county in Region B spent any monies on emergency response. Delaware and Otsego Counties did not financially support any fire protection services (NYS Office of the State Comptroller 2010a).

Table 2.83 - Region B: Expenditures for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Delaware County		**Otsego County**		**Sullivan County**		**Region B**	
	Total $	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**
General Government	$8,960,337	9.7	$18,661,059	17.9	$20,991,003	10.7	$48,612,399	12.4
Education	$623,530	0.7	$2,546,555	2.4	$6,342,470	3.2	$9,512,555	2.4
Public Safety	$5,541,817	6.0	$6,882,871	6.6	$17,902,819	9.1	$30,327,507	7.7
Health	$8,405,703	9.1	$5,563,650	5.3	$29,995,278	15.3	$43,964,631	11.2
Transportation	$18,081,013	19.5	$11,588,286	11.1	$18,465,889	9.4	$48,135,188	12.3
Social Services	$28,776,564	31.1	$37,215,496	35.6	$51,657,658	26.4	$117,649,718	30.0
Economic Development	$610,060	0.7	$1,069,964	1.0	$2,390,941	1.2	$4,070,965	1.0
Culture and Recreation	$702,837	0.8	$277,033	0.3	$2,802,213	1.4	$3,782,083	1.0
Community Services	$3,172,734	3.4	$2,047,629	2.0	$1,087,185	0.6	$6,307,548	1.6
Utilities	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Sanitation	$3,906,766	4.2	$1,065,180	1.0	$4,312,952	2.2	$9,284,898	2.4
Employee Benefits	$10,972,513	11.9	$15,976,297	15.3	$30,048,837	15.4	$56,997,647	14.5
Debt Service	$2,826,085	3.1	$1,606,314	1.5	$9,742,478	5.0	$14,174,877	3.6
Total Expenditures	$92,579,959	100.0	$104,500,334	100.0	$195,739,723	100.0	$392,820,016	100.0

Source: NYS Office of the State Comptroller 2010a.

Region C

Table 2.84 lists the main sources of county government revenues for Region C. Revenues collected in Region C totaled approximately $501.4 million for the fiscal year ending December 31, 2009. Most of the revenues were derived from local sources. Local revenue, including ad valorem (real and personal property) tax receipts and services, accounted for approximately 70.8% of total revenues in Region C (NYS Office of the State Comptroller 2010a).

Table 2.84 - Region C: Revenues for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Taxes[1] (% of total)	**Services[2] (% of total)**	**Subtotal Local Revenue (% of total)**	**State/ Federal Aid (% of total)**	**Subtotal Local// (% of total)**	**Other Sources[3] (% of total)**	**Total Revenue[4]**
Cattaraugus County	$78.1 (36.4)	$73.6 (34.3)	$151.7 (70.6)	$42.7 (19.9)	$194.4 (90.5)	$20.4 (9.5)	$214.8
Chautauqua County	$114.8 (40.1)	$88.5 (30.9)	$203.3 (70.9)	$65.0 (22.7)	$268.3 (93.6)	$18.3 (6.4)	$286.6
Region C	$192.9 (38.5)	$162.1 (32.3)	$355.0 (70.8)	$107.7 (21.5)	$462.7 (92.3)	$38.7 (7.7)	$501.4

Source: NYS Office of the State Comptroller 2010a.

1 Taxes include real property taxes and assessments, other real property tax items, sales and use taxes, and other non-property taxes.

2 Services include charges for services, charges to other governments, use and sale of property, and other local revenues.

3 Other revenues include proceeds of debt and all other sources of revenue.

4 Totals may not equal sum of components due to rounding

As shown in Table 2.85, the total local tax revenue in Region C during the fiscal year ending on December 31, 2009, was approximately $192.8 million. Of the total receipts, 53.2% was derived from taxes levied on real property, special assessments, and other real property tax items. Sales tax and distribution accounted for approximately 45.1% of the total (NYS Office of the State Comptroller 2010a).

Table 2.85 - Region C: Local Tax Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Real Property Taxes (% of total)	Special Assessments (% of total)	Other Real Property Tax Items[1] (% of total)	Sales Tax and Distribution (% of total)	Miscellaneous Use Taxes (% of total)	Other Non-Property Taxes[2] (% of total)	Total Tax Collection[3]
Cattaraugus County	$42.0 (53.8%)	$0 (0%)	$2.6 (3.3%)	$33.1 (42.4%)	$0 (0%)	$0.3 (0.4%)	$78.0
Chautauqua County	$54.2 (47.2%)	$0 (0%)	$3.7 (3.2%)	$53.8 (46.9%)	$1.2 (1.0%)	$1.9 (1.7%)	$114.8
Region C	$96.2 (49.9%)	$0 (0%)	$6.3 (3.3%)	$86.9 (45.1%)	$1.2 (0.6%)	$2.2 (1.1%)	$192.8

Source: NYS Office of the State Comptroller 2010a.

1 Other real property tax items include STAR payments, payments in lieu of taxes, interest penalties, gain from sale of tax acquired property, and miscellaneous tax items.

2 Other non-property taxes include franchises, emergency telephone system surcharges, city income taxes, and other miscellaneous non-property taxes.

3 Totals may not equal sum of components due to rounding.

Cattaraugus and Chautauqua Counties are both split between Medina Region 2 and Medina Region 3, natural-gas-producing regions designated by New York State. The final gas unit of production value for Medina Region 2 and Medina Region 3 was $11.19 in 2010; the 2011 tentative gas unit of production value is $11.32 (NYSDTF 2011). The 2010 overall full-value millage rates for Cattaraugus and Chautauqua Counties were 35.50 and 32.10, respectively (see Table 2.86). These rates have already been equalized and include the rates of all taxing districts in the county, including county, town, village, school district, and other special district rates.

Table 2.86 - Gas Economic Profile for Medina Region 2 and State Equalization Rates and Millage Rates for Region C (New August 2011)

	Final Gas Unit of Production Value (2010)[a]	Millage Rate[b] (2010)
Cattaraugus County	$11.19	35.50
Chautauqua County	$11.19	32.10

Sources:

a NYSDTF 2011.

b NYS Office of the State Comptroller 2010b. Millage rates represent the "overall full-value tax rate" and include the rates of all taxing districts in the county, including county, town, village, school district, and special districts rates.

Table 2.87 presents local government expenditures for Region C during the fiscal year ending December 31, 2009. Social services combined to create the largest single expenditure in both Cattaraugus and Chautauqua Counties, and thus in Region C. Approximately 30% of the counties' collective operating and capital budgets were spent on social services during the fiscal year ending December 31, 2009. Expenditure categories within social services include social service administration, financial assistance, Medicaid, non-Medicaid medical assistance, housing assistance, employment services, youth services, public facilities, and miscellaneous social services. Other major expenditures in Region C included general government (19.7%), employee benefits (13.4%), and transportation (10.2%). Public safety accounted for approximately 7.2% of total expenditures in Region C, including $12,866,430 for police, $260,959 for fire protection, and $100,667 for emergency response (NYS Office of the State Comptroller 2010a).

Table 2.87 - Region C: Expenditures for FY Ending December 31, 2009 (New August 2011)

	Cattaraugus County		**Chautauqua County**		**Region B**	
	Total $	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**
General Government	$38,547,702	20.2	$51,753,045	19.4	$90,300,747	19.7
Education	$6,779,075	3.5	$10,119,356	3.8	$16,898,431	3.7
Public Safety	$13,349,284	7.0	$19,805,376	7.4	$33,154,660	7.2
Health	$23,233,153	12.2	$14,164,348	5.3	$37,397,501	8.2
Transportation	$20,346,282	10.7	$26,489,032	9.9	$46,835,314	10.2
Social Services	$49,828,802	26.1	$87,553,524	32.8	$137,382,326	30.0
Economic Development	$1,278,250	0.7	$3,395,624	1.3	$4,673,874	1.0
Culture and Recreation	$1,489,536	0.8	$694,416	0.3	$2,183,952	0.5
Community Services	$2,877,290	1.5	$3,752,921	1.4	$6,630,211	1.4
Utilities	$0	0.0	$21,402	<0.1	$21,402	<0.1
Sanitation	$2,004,345	1.0	$7,288,201	2.7	$9,292,546	2.0
Employee Benefits	$23,122,461	12.1	$38,268,359	14.4	$61,390,820	13.4
Debt Service	$8,144,509	4.3	$3,368,753	1.3	$11,513,262	2.5
Total Expenditures	**$191,000,689**	**100.0**	**$266,674,357**	**100.0**	**$457,675,046**	**100.0**

Source: NYS Office of the State Comptroller 2010a.

2.4.11.5 Environmental Justice

New York State

Nearly each county in New York State has census block groups that may be considered potential EJ areas. The term "environmental justice" refers to a Federal policy established by Executive Order 12898 (59 Federal Register [FR] 7629) under which each Federal agency identifies and

addresses, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority or low-income populations. In response to EO 12898 the U.S. Environmental Protection Agency developed a definition of EJ as follows:

> *The fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Fair treatment means that no group of people, including a racial, ethnic, or socioeconomic group, should bear a disproportionate share of the negative environmental consequences resulting from industrial, municipal, and commercial operations or the execution of federal, state, local, and tribal programs and policies.*

The Department's Commissioner Policy 29 (the Policy) on Environmental Justice and Permitting expands upon Executive Order 12898, defining a potential EJ area as a minority or low-income community that bears a disproportionate share of the negative environmental consequences resulting from industrial, municipal, and commercial operations or the execution of federal, state, local, and tribal programs and policies.

The New York State Policy defines a minority population as a group of individuals that are identified or recognized as African-American, Asian American/Pacific Islander, American Indian, or Hispanic. A minority community exists where a census block group, or multiple census block groups, has a minority population equal to or greater than 51.1% in urban areas or 33.8% in rural areas. Rural and urban area classifications are established by the USCB. Urban area means all territory, population, and housing units located in urbanized areas and in places of 2,500 or more inhabitants outside of an urbanized area. An urbanized area is a continuously built-up area with a population of 50,000 or more. Rural area means territory, population, and housing units that are not classified as an urban area.

A low-income population is defined by the Policy as a group of individuals having an annual income that is less than the poverty threshold established by the USCB. A low-income community is a census block group, or area with multiple census block groups, having a low-

income population equal to or greater than 23.59% of the total population for whom poverty status is determined.

The Policy applies to applications for major projects and major modifications for the permits authorized by the following sections of the Environmental Conservation Law:

- Titles 7 and 8 of Article 17, SPDES (implemented by 6 NYCRR Part 750 et seq.);
- Article 19, Air Pollution Control (implemented by 6 NYCRR Part 201 et seq.);
- Title 7 of Article 27, solid waste management (implemented by 6 NYCRR Part 360): including minor modifications involving any tonnage increases beyond the approved design capacity and minor modifications involving an increase in the amount of putrescible solid waste beyond the amount that has already been approved in the existing permit;
- Title 9 of Article 27, industrial hazardous waste management (implemented by 6 NYCRR Part 373); and
- Title 11 of Article 27, siting of industrial hazardous waste facilities (implemented by 6 NYCRR Part 361).

A Department permit applicant must conduct a preliminary screen to identify whether the proposed action is located in a potential EJ area. The applicant also must identify potential adverse environmental impacts within the area to be affected. The Department provides online mapping for each New York State county to assist applicants in identifying potential EJ areas. Census block data is utilized to identify these areas. The mapping referenced in this section was last updated in 2005.

The following provides a discussion of the minority and low-income populations in the state and in each of the representative regions for background information.

In 2010, the percent minority population in New York State was 34.25%. The Hispanic population was 17.6% in 2010; and the percent of persons living below poverty level in 2009 was 13.9%.

According to the *2010 Census of Population and Housing*, approximately 97.0% of residents of New York State identify themselves as being of a single race: 65.8% of the population of New

York State self-identify as White; 15.9% as Black or African American; 0.6% as American Indian and Alaska Native; 7.3% as Asian; less than (<) 0.1% as Native Hawaiian and Other Pacific Island; and 7.4% as some other race (USCB 2010). The remaining 3.0% of the population self-identifies as two or more races (see Table 2.88).

Persons of Hispanic or Latino origin are defined as individuals who identified themselves as Hispanic or Latino on the 2010 Census, regardless of race. In New York State, 17.6% of the population self-identifies as being Hispanic or Latino.

Table 2.88 presents a summary of the total population of New York State by the race/ethnicity categories defined by the USCB.

Table 2.88 - Racial and Ethnicity Characteristics for New York State (New August 2011)

Population Category	Population	Percentage of Total 2010 Population
Total 2010 Population	19,378,102	100.0%
White Only	12,740,940	65.8%
Black or African American Only	3,073,800	15.9%
American Indian and Alaska Native Only	106,906	0.6%
Asian Only	1,420,244	7.3%
Native Hawaiian and Other Pacific Islander Only	8,766	< 0.1%
Some Other Race Only	1,441,563	7.4%
Total Population of One Race	18,792,219	97.0%
Two or more races	585,849	3.0%
Hispanic or Latino	3,416,922	17.6

Source: USCB 2010.
The categories presented in this table are defined by the USCB. A person must have self-identified during the 2010 census to be included within any of these categories in the *2010 Census of Population and Housing*.

Region A

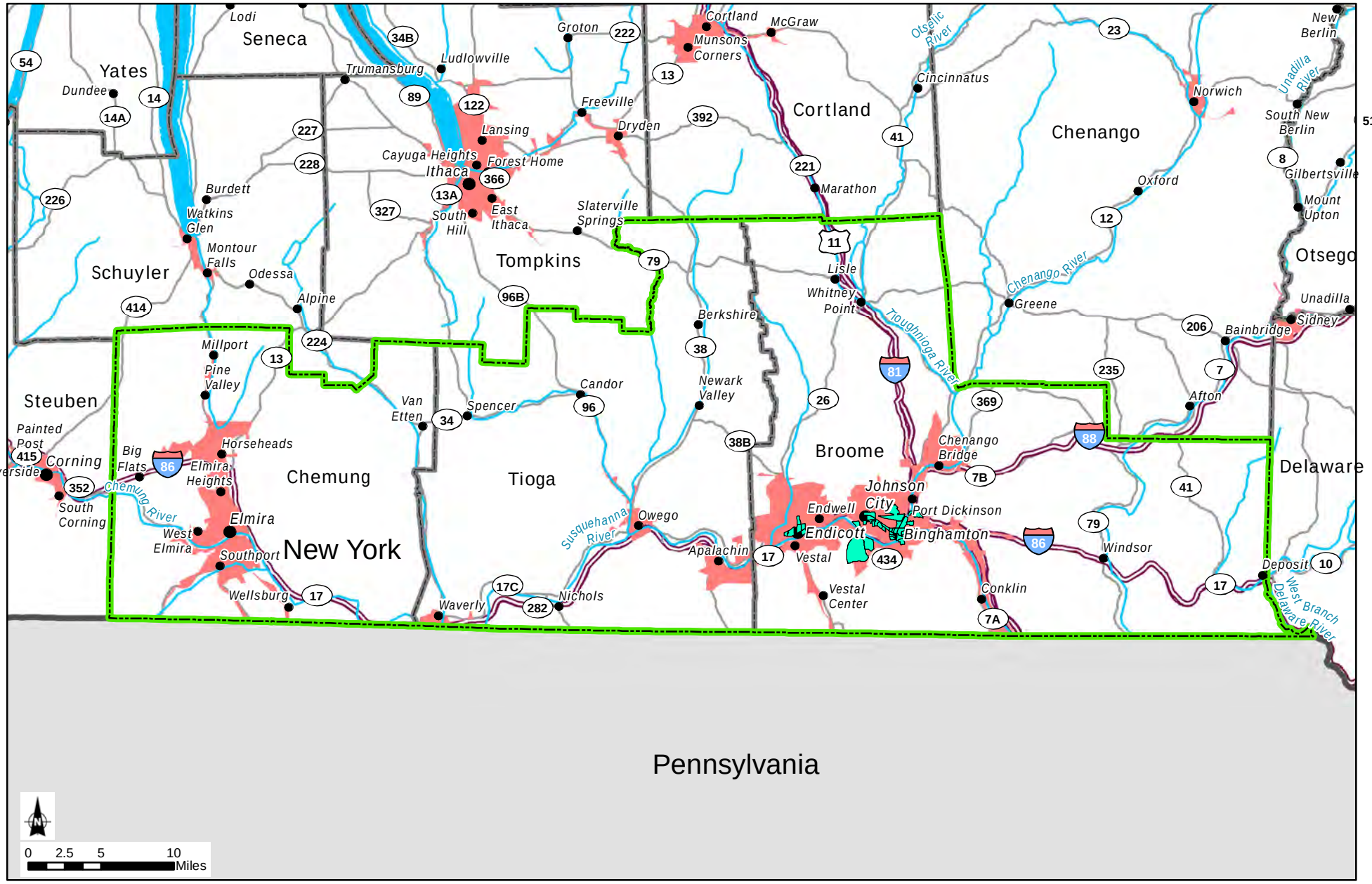
In 2010, the combined percent minority for Region A was 10.51%. Chemung and Broome Counties had similar percentages of minority population, while Tioga County had a relatively low percentage (3.07% minority). Region A had a combined percent Hispanic population of 1.82%. The counties which comprise Region A, both collectively and individually, are not considered minority communities.

The combined poverty level of Region A in 2009 was 14.4% in 2009, while Tioga County had a lower percentage (10.0%) than Broome and Chemung Counties. The poverty level for Region A is lower than the New York State EJ threshold for a low-income community (23.59%).

The Department's 2005 preliminary screen mapping for each county identifies potential EJ areas at the census block group level. These maps were combined to illustrate potential EJ areas in Region A (Figure 2.7). The mapping indicates that some census blocks in Chemung County (towns of Elmira and Ashland); Tioga County (towns of Barton and Owego); and Broome County (towns of Vestal and Kirkwood) are potential EJ areas based on their minority and/or low-income populations.

According to the *2010 Census of Population and Housing*, approximately 97.6% of the individuals in Region A identify themselves as being of a single race: 89.5% of the population of Region A self-identifies as White; 4.6% as Black or African American; 0.2% as American Indian and Alaska Native; 2.5% as Asian; less than (<) 0.1% as Native Hawaiian and Other Pacific Island; and 0.8% as some other race (USCB 2010). The remaining 2.4% self-identifies as two or more races.

In Region A, 1.8% of the population self-identifies as being Hispanic or Latino. Table 2.89 presents a summary of the total population of Region A by the race/ethnicity categories defined by the USCB.



Representative Region A
County Boundary
State Boundary
Urban Area
River/Stream
Highway/Major Road
Secondary Road
Potential Environmental Justice Area

Figure 2.7: Potential Environmental Justice Areas for Region A

Source: NY DEC, 2005, http://www.dec.ny.gov/docs/permits_ej_operations_pdf/broomeco.pdf; USGS, 2002

Table 2.89 - Region A: Racial and Ethnicity Characteristics (New August 2011)

Population Category	Population	Percentage of Total 2010 Population
Broome County		
Total 2010 Population	200,600	100.0%
White Only	176,444	88.0%
Black or African American Only	9,614	4.8%
American Indian and Alaska Native Only	396	0.2%
Asian Only	7,065	3.5%
Native Hawaiian and Other Pacific Islander Only	82	<0.1%
Some Other Race Only	1,912	1.0%
Total Population of One Race	195,513	97.5%
Two or more races	5,087	2.5%
Hispanic or Latino	4,334	2.2%
Chemung County		
Total 2010 Population	88,830	100.0%
White Only	78,771	88.7%
Black or African American Only	5,828	6.6%
American Indian and Alaska Native Only	233	0.3%
Asian Only	1,057	1.2%
Native Hawaiian and Other Pacific Islander Only	20	< 0.1%
Some Other Race Only	539	0.6%
Total Population of One Race	86,448	97.4%
Two or more races	2,372	2.7%
Hispanic or Latino	1,436	1.6%
Tioga County		
Total 2010 Population	51,125	100.0%
White Only	49,556	96.9%
Black or African American Only	375	0.7%
American Indian and Alaska Native Only	86	0.2%
Asian Only	372	0.7%
Native Hawaiian and Other Pacific Islander Only	15	<0.1%
Some Other Race Only	146	0.3%
Total Population of One Race	50,550	98.9%
Two or more races	575	1.1%
Hispanic or Latino	412	0.8%
Region A Total		
Total 2010 Population	340,555	100.0%
White Only	304,771	89.5%
Black or African American Only	15,817	4.6%
American Indian and Alaska Native Only	715	0.2%
Asian Only	8,494	2.5%
Native Hawaiian and Other Pacific Islander Only	117	< 0.1%
Some Other Race Only	2,597	0.8%
Total Population of One Race	332,511	97.6%
Two or more races	8,034	2.4%
Hispanic or Latino	6,182	1.8%

Source: USCB 2010.

The categories presented in this table are defined by the USCB. A person must have self-identified during the 2010 census to be included within any of these categories in the *2010 Census of Population and Housing.*

Region B

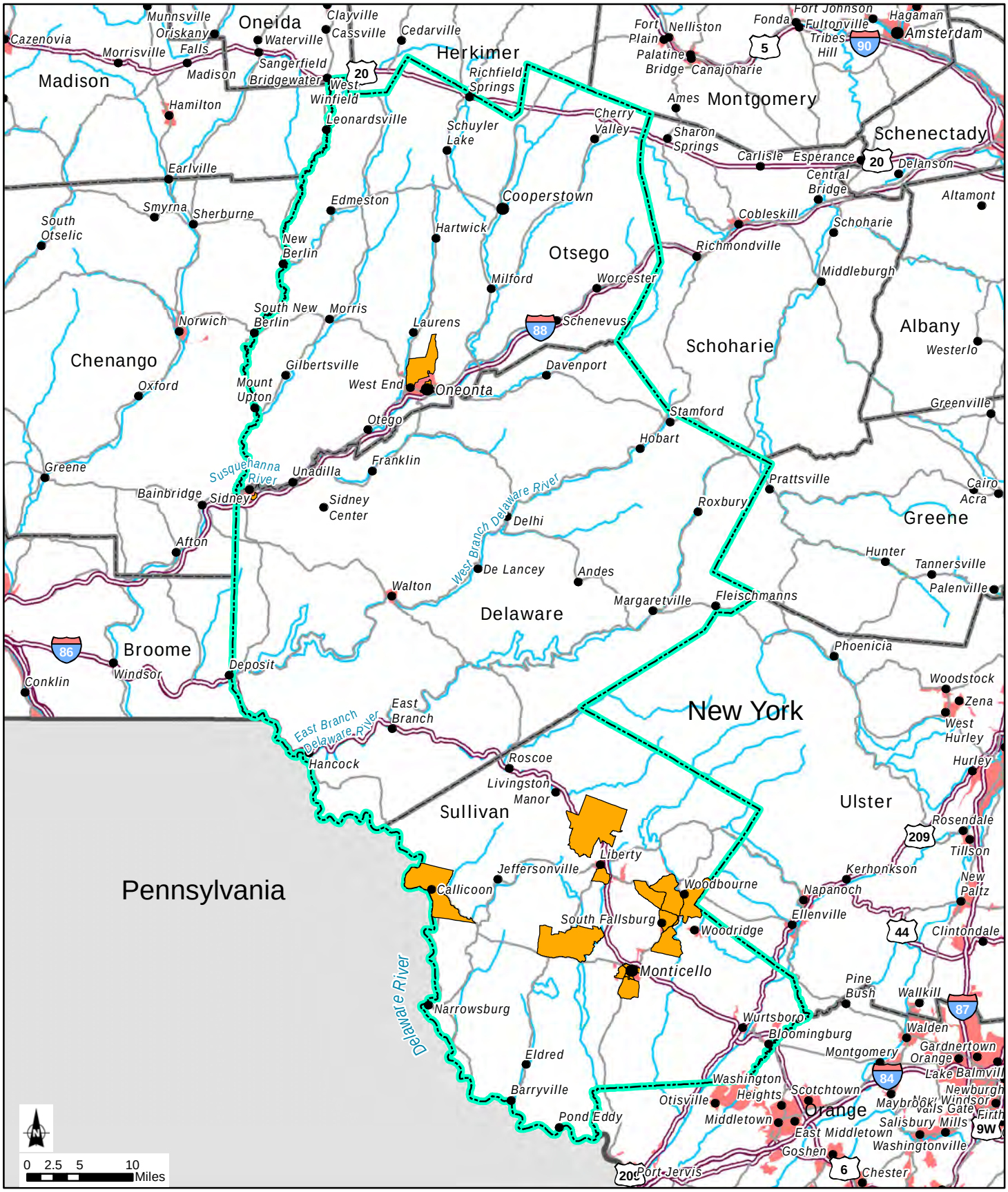
Region B comprises three counties: Sullivan, Delaware, and Otsego Counties. The 2010 combined percent minority for Region B was 10.45%. Delaware and Otsego Counties had similar percentages of minority population, while Sullivan County had a relatively higher percentage (18.04% minority). Region B had a combined percent Hispanic population of 5.02%, with Sullivan County having a slightly higher percentage of Hispanic persons at approximately 9% of total population. The counties which comprise Region B are not considered minority communities. The combined poverty level of Region B was 15.0% in 2009. The poverty level for Region B is lower than the New York State EJ threshold for a low-income community (23.59%).

The Department's 2005 preliminary screen mapping for each county identifies potential EJ areas at the census block group level. These maps were combined to illustrate potential EJ areas in Region B (Figure 2.8). The mapping indicates that some census blocks in Otsego County (town of Oneonta) and Sullivan County (towns of Delaware, Rockland, Liberty, Fallsburg, Bethel, and Thompson) are potential EJ areas based on their minority and/or low-income populations. There are no mapped potential EJ areas in Delaware County.

According to the *2010 Census of Population and Housing*, approximately 97.9% of the individuals in Region B identify themselves as being of a single race: 89.6% of the population of Region B self-identifies as White; 4.7% as Black or African American; 0.3% as American Indian and Alaska Native; 1.1% as Asian; less than (<) 0.01% as Native Hawaiian and Other Pacific Island; and 2.1% as some other race (USCB 2010). The remaining 2.1% self-identify as being of two or more races.

Persons of Hispanic or Latino origin are defined as individuals who identified themselves as a Hispanic or Latino on the 2010 Census, regardless of race. In Region B, 5.0% of the population self-identifies as being Hispanic or Latino.

Table 2.90 presents a summary of the total population of Region B by the race/ethnicity categories defined by the USCB.



Representative Region B
County Boundary
State Boundary
Urban Area
River/Stream
Highway/Major Road
Secondary Road
Potential Environmental Justice Area

Figure 2.**8**: Potential Environmental Justice Areas for Region B

Source: NY DEC, 2005, http://www.dec.ny.gov/docs/permits_ej_operations_pdf/broomeco.pdf; USGS, 2002

Table 2.90 - Region B: Racial and Ethnicity Characteristics (New August 2011)

Population Category	Population	Percentage of Total 2010 Population
Delaware County		
Total 2010 Population	47,980	100.0%
White Only	45,675	95.2%
Black or African American Only	779	1.6%
American Indian and Alaska Native Only	131	0.3%
Asian Only	367	0.8%
Native Hawaiian and Other Pacific Islander Only	12	< 0.1%
Some Other Race Only	394	0.8%
Total Population of One Race	47,358	98.7%
Two or more races	622	1.3%
Hispanic or Latino	1,058	2.2%
Otsego County		
Total 2010 Population	62,259	100.0%
White Only	58,935	94.7%
Black or African American Only	1,066	1.7%
American Indian and Alaska Native Only	121	0.2%
Asian Only	674	1.1%
Native Hawaiian and Other Pacific Islander Only	18	< 0.1%
Some Other Race Only	413	0.7%
Total Population of One Race	61,227	98.4%
Two or more races	1,032	1.7%
Hispanic or Latino	1,391	2.2%
Sullivan County		
Total 2010 Population	77,547	100.0%
White Only	63,560	82.0%
Black or African American Only	7,039	9.1%
American Indian and Alaska Native Only	354	0.5%
Asian Only	1,075	1.4%
Native Hawaiian and Other Pacific Islander Only	24	< 0.1%
Some Other Race Only	3,229	4.2%
Total Population of One Race	75,281	97.2%
Two or more races	2,266	2.9%
Hispanic or Latino	6,986	9.0%
Region B Total		
Total 2010 Population	187,786	100.0%
White Only	168,170	89.6%
Black or African American Only	8,884	4.7%
American Indian and Alaska Native Only	606	0.3%
Asian Only	2,116	1.1%
Native Hawaiian and Other Pacific Islander Only	54	< 0.1%
Some Other Race Only	4,036	2.1%
Total Population of One Race	183,866	97.9%
Two or more races	3,920	2.1%
Hispanic or Latino	9,435	5.0%

Source: USCB 2010.

The categories presented in this table are defined by the USCB. A person must have self-identified during the 2010 census to be included within any of these categories in the *2010 Census of Population and Housing*.

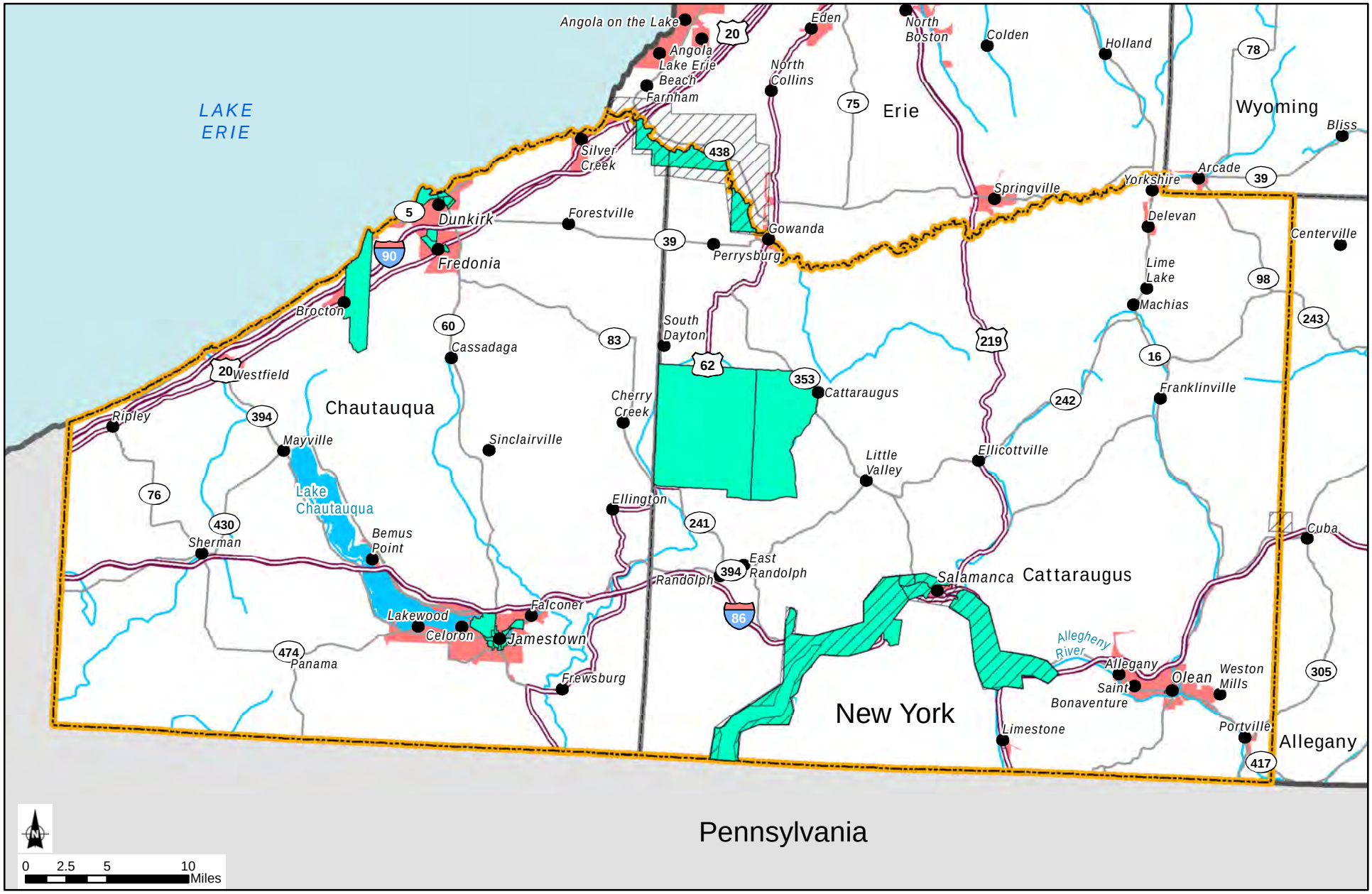
Region C

Region C comprises Chautauqua and Cattaraugus Counties. The 2010 combined percent minority for Region C was 7.30%. Region C had a combined percent Hispanic population of 2.68%, with Chautauqua County having a higher percentage (3.70%) than Cattaraugus County. Region C is not considered a minority community. The combined poverty level of Region C was 2.3% in 2009. The poverty level for Region C is lower than the New York State EJ threshold for a low-income community (23.59%).

The Department's 2005 preliminary screen mapping was combined to illustrate potential EJ areas in Region C (Figure 2.9). The mapping indicates that some census blocks in Cattaraugus County are potential EJ areas based on their minority and/or low-income populations. These municipalities include Perrysburg, Leon, New Albion, Conewango, Albion, South Valley, Cold Spring, Red House, Salamanca, Carrolton, and Allegany. Some census blocks in Chautauqua County (Jamestown, Portland, Pomfret, Dunkirk and Hanover) are potential EJ areas.

According to the *2010 Census of Population and Housing*, 98.2% of the individuals in Region C identify themselves as being of a single race: 92.7% of the population of Region C self-identifies as White; 2.0% as Black or African American; 1.5% as American Indian and Alaska Native; 0.6% as Asian; less than 0.1% as Native Hawaiian and Other Pacific Island; and 1.4% as some other race (USCB 2010). The remaining 1.9% self-identify as being of two or more races.

Persons of Hispanic or Latino origin are defined as individuals who identified themselves as Hispanic or Latino on the 2010 Census, regardless of race. In Region C, 2.7% of the population self-identifies as being Hispanic or Latino.



Representative Region C
County Boundary
State Boundary
Urban Area
River/Stream
Highway/Major Road
Secondary Road
Tribal Lands Boundary
Potential Environmental Justice Area

Figure 2.**9**: Potential Environmental Justice Areas for Region C

Source: NY DEC, 2005, http://www.dec.ny.gov/docs/permits_ej_operations_pdf/broomeco.pdf; USGS, 2002

Table 2.91 presents a summary of the total population of Region C by the race/ethnicity categories defined by the USCB.

Table 2.91 - Region C: Racial and Ethnicity Characteristics (New August 2011)

Population Category	Population	Percentage of Total 2010 Population
Cattaraugus County		
Total 2010 Population	80,317	100.0%
White Only	74,639	92.9%
Black or African American Only	1,024	1.3%
American Indian and Alaska Native Only	2,443	3.0%
Asian Only	528	0.7%
Native Hawaiian and Other Pacific Islander Only	15	< 0.1%
Some Other Race Only	305	0.4%
Total Population of One Race	78,954	98.3%
Two or more races	1,363	1.7%
Hispanic or Latino	786	1.0%
Chautauqua County		
Total 2010 Population	134,905	100.0%
White Only	124,875	92.6%
Black or African American Only	3,197	2.4%
American Indian and Alaska Native Only	689	0.5%
Asian Only	688	0.5%
Native Hawaiian and Other Pacific Islander Only	36	< 0.1%
Some Other Race Only	2,669	2.0%
Total Population of One Race	132,154	98.0%
Two or more races	2,751	2.0%
Hispanic or Latino	4,991	3.7%
Region C Total		
Total 2010 Population	215,222	100.0%
White Only	199,514	92.7%
Black or African American Only	4,221	2.0%
American Indian and Alaska Native Only	3,132	1.5%
Asian Only	1,216	0.6%
Native Hawaiian and Other Pacific Islander Only	51	< 0.1%
Some Other Race Only	2,974	1.4%
Total Population of One Race	211,108	98.2%
Two or more races	4,114	1.9%
Hispanic or Latino	5,777	2.7%

Source: USCB 2010.

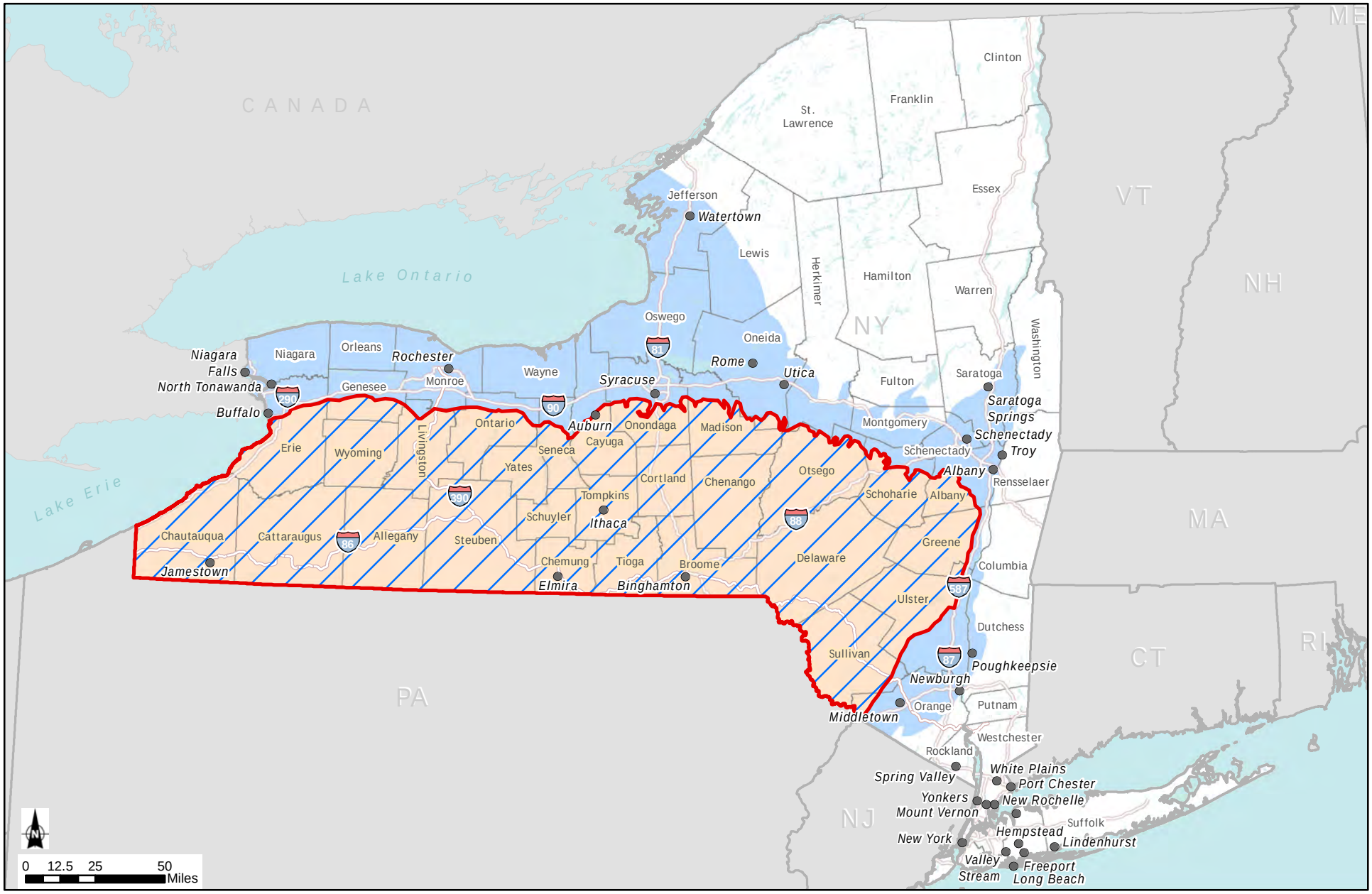
The categories presented in this table are defined by the USCB. A person must have self-identified during the 2010 census to be included within any of these categories in the *2010 Census of Population and Housing*.

2.4.12 Visual Resources[55]

As stated in Section 1.3, oil and gas drilling is expected to occur statewide, with the exceptions of (1) state-owned lands that constitute the Adirondack and Catskill Forest Preserves (the state constitution requires that these areas remain forever wild and not be leased or sold), and (2) those areas of the Adirondacks region, NYC, and Long Island where subsurface geology renders drilling for hydrocarbons unlikely. No site-specific project locations are being evaluated in the SGEIS; however, the Marcellus and Utica Shales are the most prominent shale formations in New York State, and the prospective region for the extraction of natural gas from these formations generally extends from Chautauqua County eastward to Greene, Ulster, and Sullivan Counties, and from the Pennsylvania border north to the approximate location of the east-west portion of the New York State Thruway between Schenectady and Auburn (Figure 2.10). This region covers all or parts of 30 counties. Fourteen counties are located entirely within this area, and 16 counties are located partially within the area.

For the purposes of impact analysis, visual resources located within the areas underlain by the Marcellus and Utica Shales in New York may be considered representative of the types of visual resources that would be encountered statewide. Therefore, this section describes the existing federally and state-designated visual resources within the boundaries of this area in New York. The potential for other visual resources and visually sensitive areas within the areas underlain by the Marcellus and Utica Shales in New York, which are defined by regional planning entities, county and town agencies, and local communities and their residents, is also acknowledged in this section. All of these types of visual resources and visually sensitive areas (federal, state, and local) also contribute to the 'sense of place' that defines the character of a community, which is discussed in Section 2.4.10.

[55] Subsection 2.4.12, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.



City with Year 2000 Population Greater than 25,000

Major Water Bodies

County Boundary

State Boundary

Boundary of Area of Interest for Visual Resources

Marcellus Shale Extent in New York State

Utica Shale Extent in New York State

Extent of Marcellus and Utica Shales in New York State

Figure 2.**10**: Area of Interest for Visual Resources

Source: ESRI, 2010; USGS, 2002

Criteria for identifying visual resources are defined in the Department's Program Policy DEP-00-2, "Assessing and Mitigating Visual Impacts" (NYSDEC 2000). Federally designated visual resources include, but are not limited to, National Historic Landmarks (NHL); properties listed in the National Register of Historic Places (NRHP); National Natural Landmarks (NNL); National Wildlife Refuges; National Parks, Recreation Areas, Seashores and Forests, as applicable; National Wild and Scenic Rivers and American Heritage Rivers; and National Scenic, Historic and Recreation Trails.

State-designated visual resources include, but are not limited to, properties listed or eligible for listing in the State Register of Historic Places; Heritage Areas (formerly Urban Cultural Parks); State Forest Preserves; State Game Refuges, State Wildlife Management Areas and Multiple Use Areas; State Parks, Day Use Areas, Nature Preserves and Historic Preserves; State Wild, Scenic and Recreational Rivers; State Scenic Byways, Parkways and Roads; State Conservation Areas and other sites, areas, lakes, or reservoirs designated or eligible for designation as scenic in accordance with ECL Article 49 or the DOT equivalent; Critical Environmental Areas; Scenic Areas of Statewide Significance; State Trails; and Bond Act Properties purchased under the Exceptional Scenic Beauty or Open Space Category. The New York Statewide Trails Plan, Open Space Conservation Plan, and Statewide Comprehensive Outdoor Recreation Plan were also consulted during the development of the existing environmental setting for visual resources (OPRHP 2008, 2009, 2010).

Based on NYSDEC Program Policy DEP-00-2, the visual resources analysis for this draft SGEIS includes the following:

- The definitions of the specific visual resource or visually sensitive area, including descriptions of relevant regulations, where appropriate.
- The number of the specific visual resources or visually sensitive areas within the area underlain by the Marcellus and Utica Shales in New York organized by county, where appropriate.
- Figures showing the locations of specific visual resources or visually sensitive areas within the area underlain by the Marcellus and Utica Shales in New York.

- Where appropriate, a table summarizing information for specific visual resources or visually sensitive areas, generally focusing on visual, aesthetic, or scenic qualities of the resource, if known, and organized by county.

2.4.12.1 Historic Properties and Cultural Resources

This section discusses historic properties and other cultural resources that are considered visual resources per NYSDEC Program Policy DEP-00-2, including properties listed in the National and State Registers of Historic Places (including National Historic Landmarks), state historic sites, state historic parks, and state heritage areas (formerly urban cultural parks) (NYSDEC 2000). Historic properties and cultural resources are often considered significant partly because of their associated visual or aesthetic qualities. These visual or aesthetic qualities may be related to the integrity of the appearance of these properties or resources, or to the integrity of their settings. Viewsheds can also contribute to the significance of historic properties or cultural resources, and viewsheds that contain historic properties and cultural resources may be considered significant because of their presence in the landscape.

A property on or eligible for inclusion in the National or State Register of Historic Places (16 U.S.C. §470a et seq., Parks, Recreation and Historic Preservation Law Section 14.07)

Historic properties are defined as those properties that have been listed in, or determined eligible for listing in, the NRHP (Advisory Council on Historic Preservation 2011). The NRHP, which is the official list of the nation's historic places worthy of preservation, was established under the National Historic Preservation Act of 1966, as amended (NPS 2011a; OPRHP 2011a). In general, historic properties are 50 years old or older, and they retain much of their original appearance because of the integrity of their location, design, setting, materials, workmanship, feeling, and association (OPRHP 2011a).

The National Park Service (NPS) maintains a database of properties listed in the NRHP. (This database does not include information for other properties determined to be eligible for listing in the NRHP.) At least 1,050 NRHP-listed properties have been identified within the area underlain by the Marcellus and Utica Shales in New York (Table 2.92) (NPS 2011b, ESRI 2011). The significance of properties listed or eligible for listing on the NRHP may be derived in varying degrees from scenic or aesthetic qualities that may be considered visually sensitive.

Table 2.92 - Number of NRHP-Listed Historic Properties within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name	Number of NRHP-listed Historic Properties within Entire County
Albany*	7
Allegany	27
Broome	52
Cattaraugus	26
Cayuga*	44
Chautauqua	45
Chemung	32
Chenango	39
Cortland	25
Delaware	62
Erie*	28
Genesee*	6
Greene*	45
Livingston*	74
Madison*	48
Oneida*	2
Onondaga*	18
Ontario*	37
Orange*	3
Otsego*	53
Schoharie*	15
Schuyler	14
Seneca*	10
Steuben	49
Sullivan*	64
Tioga	53
Tompkins	57
Ulster*	32
Wyoming	18
Yates	65
Total	1,050

Sources: NPS 2011b; ESRI 2010.

* Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.

The State Register of Historic Places, which is the official list of New York State's historic places worthy of preservation, was established under the New York State Historic Preservation act of 1980. The eligibility criteria for properties listed in the State Register of Historic Places are the same as the eligibility criteria for the NRHP (OPRHP 2011a). The OPRHP maintains the database of records for properties listed in, or determined eligible for listing in, the State and

National Registers of Historic Places (OPRHP 2011b). Over 250,000 properties located across New York State are included in this database, and the database provides information on whether the properties have been evaluated for State and/or National Register eligibility, and if evaluated, the eligibility status of the resource (OPRHP 2011c). The significance of properties listed or eligible for listing in the State Register of Historic Places may be derived in varying degrees from scenic or aesthetic qualities that may be considered visually sensitive.

National Heritage Areas

National Heritage Areas (NHAs) are designated by Congress. For an area to be considered for designation, certain key elements must be present. Of primary importance, the landscape must have nationally distinctive natural, cultural, historic, and scenic resources that, when linked together, tell a unique story about the nation. NHAs are not units of the NPS, nor are they owned or managed by the NPS. Each NHA is governed by separate authorizing legislation and operates under provisions unique to its resources and desired goals. The heritage area concept offers an innovative method for citizens, in partnership with local, state, and federal governments and nonprofit and private sector interests, to shape the long-term future of their communities (NPS 2010d, 2011g).

Two NHAs are located partially within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.11): portions of the Erie Canalway National Heritage Corridor in Erie, Ontario, Yates, Seneca, Cayuga, Schuyler, and Tompkins Counties; and portions of the Hudson River Valley NHA in Albany, Greene, Ulster, and Sullivan Counties (OPRHP 2007; NPS 2010d, 2011e; Erie Canalway National Heritage Corridor 2008; Hudson River Valley National Heritage Corridor 2011). These NHAs are likely to contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.

Properties Designated as National Historic Landmarks

National Historic Landmarks (NHLs) are nationally significant historic places designated by the Secretary of the Interior because they possess exceptional value or quality in illustrating or interpreting the heritage of the United States (NPS 2011c). There are 19 NHLs located within the area underlain by the Marcellus and Utica Shales in New York (Table 2.93 and Figure 2.11). Generally, these NHLs are historic buildings (residences, churches, civic buildings, and

institutional buildings), but other types of historic properties are also represented, including battlefields and canals (Table 2.93). The significance of NHL-designated properties may be derived in varying degrees from scenic or aesthetic qualities that may be considered visual resources or visually sensitive.

State Historic Sites and Historic Parks

State Historic Sites and State Historic Parks are historic and cultural places that tell the story of the New York State's rich heritage. Owned by New York State, these places are preserved and interpreted for the public's enjoyment, education, and enrichment (OPRHP 2011d). There are 12 State Historic Sites and two State Historic Parks in the counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York (OPRHP 2008). Of these 14 historic and cultural places, only two are within the area underlain by the Marcellus and Utica Shales in New York: Genesee Valley Canal State Historic Site in Livingston County and Lorenzo State Historic Site in Madison County (see Figure 2.11) (OPRHP 2011d). State Historic Sites and State Historic Parks may contain scenic or aesthetic qualities that may be considered visually sensitive.

Local Visually Sensitive Resources or Areas

The counties that are entirely or partially located within the area underlain by the Marcellus and Utica Shales in New York are expected to contain numerous other local visual resources or visually sensitive areas. These local visual resources or visually sensitive areas would be identified, defined and/or designated by regional planning entities and local (county and town) communities and their residents and would be in addition to the visual resources or visually sensitive areas described above that are defined or designated by federal and state agencies and guidance.

Table 2.93 - National Historic Landmarks (NHLs) Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of NHLs within County	Names of NHLs
Broome	1	• New York State Inebriate Asylum
Cayuga**	6	• William H. Seward House • Harriet Tubman Home for the Aged • Harriet Tubman Residence • Thompson A.M.E. Zion Church • Willard Memorial Chapel-Welch Memorial Hall • Jethro Wood House
Chautauqua	2	• Chautauqua Historic District • Lewis Miller Cottage, Chautauqua Institute
Chemung	1	• Newton Battlefield
Delaware	1	• John Burroughs Memorial (Woodchuck Lodge)
Erie**	2	• Millard Fillmore House • Roycroft Campus
Madison**	1	• Gerrit Smith Estate
Orange**	1	• Delaware and Hudson Canal***
Otsego**	1	• Hyde Hall
Seneca**	1	• Rose Hill
Sullivan**	1	• Delaware and Hudson Canal***
Tompkins	1	• Morrill Hall, Cornell University
Ulster**	2	• John Burroughs Riverby Study • Delaware and Hudson Canal***
Total	**19**	

Sources: ESRI 2010; NPS 2011d; OPRHP 2008.

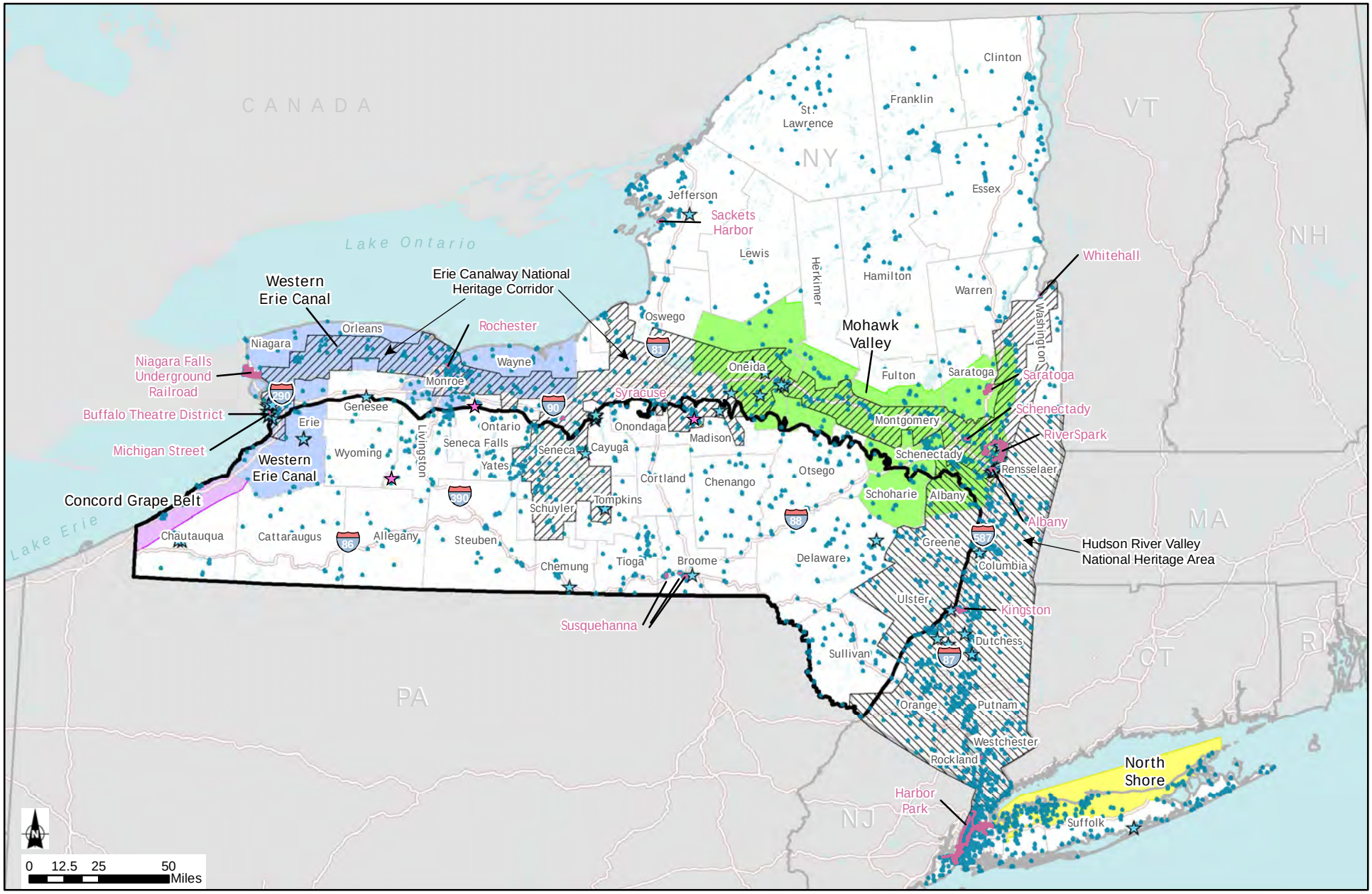
* There are no NHLs within other counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.

*** The Delaware and Hudson Canal NHL traverses portions of three counties (Orange, Sullivan, and Ulster).

State Heritage Areas (former Urban Cultural Parks [Parks, Recreation and Historic Preservation Law Section 35.15])

The State Heritage Area System, formerly known as the Urban Cultural Park System, is a state and local partnership established to preserve and develop areas that have special significance to New York State (OPRHP 2011e). New York State Heritage Areas are places where unique qualities of geography, history, and culture create a distinctive identity that becomes the focus of four heritage goals: preservation of significant resources; education that interprets lessons from the past; recreation and leisure activities; and economic revitalization for sustainable communities (OPRHP 2011f). Four regional or urban heritage areas or corridors are located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.11): the Concord Grape Belt (Lake Erie) Heritage Area in Chautauqua and Cattaraugus Counties; portion of the Western Erie Canal Heritage Area in southern Erie County; portions of the Mohawk Valley Heritage Area in Oneida, Schoharie, and Albany Counties; and the Susquehanna Heritage Area in Broome County (OPRHP 2007, 2011e; 2011f; Concord Grape Belt Heritage Association 2011; Western Erie Canal Alliance 2010-2011). These State Heritage Areas are likely to contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.



Major Water Bodies
County Boundary
State Boundary
Boundary of Area of Interest for Visual Resources
Erie Canalway NHA
Hudson River Valley NHA
State Urban Hertage Area
State Regional Heritage Area
Western Erie Canal
Concord Grape Belt
Mohawk Valley
North Shore
National Register of Historic Places Site
National Historic Landmark
State Historic Site

Figure 2.**11**: Visually Sensitive Areas Associated with Historic Properties and Cultural Resources

Source: ESRI, 2010; USGS, 2002; OPRHP, 2007, 2009, 2011; NYCSCIC, 2005; NPS, 2007

2.4.12.2 Parks and Other Recreation Areas

This section discusses parks and other recreation areas that are considered visual resources per NYSDEC Program Policy DEP-00-2, "Assessing and Mitigating Visual Impacts," including state parks; properties included in the National Park System and areas defined as national recreation areas, seashores and forests; and state or federally designated trails (NYSDEC 2000). These recreation areas often contain scenic areas and/or are developed partly because of their associated visual or aesthetic qualities.

State Parks [Parks, Recreation and Historic Preservation Law Section 14.07]

State Parks contain natural, historic, cultural, and/or recreational resources of significance to New York State. (Note that State Historic Parks are discussed separately in Section 2.4.12.1). Owned by New York State, these parks are maintained for the public's use. Thirty-four state parks are located partially or entirely within the area underlain by the Marcellus and Utica Shales in New York (Table 2.94 and Figure 2.12) (OPRHP 2008). These parks may contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.

Table 2.94 - State Parks Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of State Parks within County	Names of State Parks within County
Albany**	1	• John Boyd Thacher State Park
Broome	2	• Chenango Valley State Park • Oquaga Creek State Park
Cattaraugus	1	• Allegany State Park
Cayuga**	2	• Fillmore Glen State Park • Long Point State Park
Chautauqua	2	• Lake Erie State Park • Long Point on Lake Chautauqua State Park
Chemung	1	• Mark Twain State Park
Chenango	2	• Hunts Pond State Park • Bowman Lake State Park
Delaware	1	• Oquaga Creek State Park
Erie**	3	• Evangola State Park • Woodlawn Beach State Park • Knox Farm State Park
Genesee**	1	• Darien Lakes State Park
Livingston**	1	• Letchworth State Park
Madison**	2	• Chittenango Falls State Park • Helen L McNitt State Park (undeveloped)
Otsego**	3	• Gilbert Lake State Park • Betty and Wilbur Davis State Park • Glimmerglass State Park
Schoharie**	2	• Max V. Shaul State Park • Mine Kill State Park
Schuyler	1	• Watkins Glen State Park
Seneca**	3	• Seneca Lake State Park • Sampson State Park • Taughannock Falls State Park
Steuben	2	• Stony Brook State Park • Pinnacle State Park
Sullivan**	1	• Lake Superior State Park
Tompkins	3	• Taughannock Falls State Park • Robert H. Treman State Park • Buttermilk Falls State Park
Wyoming	2	• Letchworth State Park • Silver Lake State Park (undeveloped)
Yates	1	• Keuka Lake State Park
Total	34***	

Sources: ESRI 2010; OPRHP 2008.

* No state parks within other counties entirely or partially within the area underlain by the Marcellus and Utica Shales in NYS.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.

***Letchworth State Park is in two counties (Wyoming and Livingston); Oquaga Creek State Park is in two counties (Broome and Delaware); Taughannock Falls State Park is in two counties (Seneca and Tompkins).

The National Park System, Recreation Areas, Seashores, Forests (16 U.S.C. 1c)

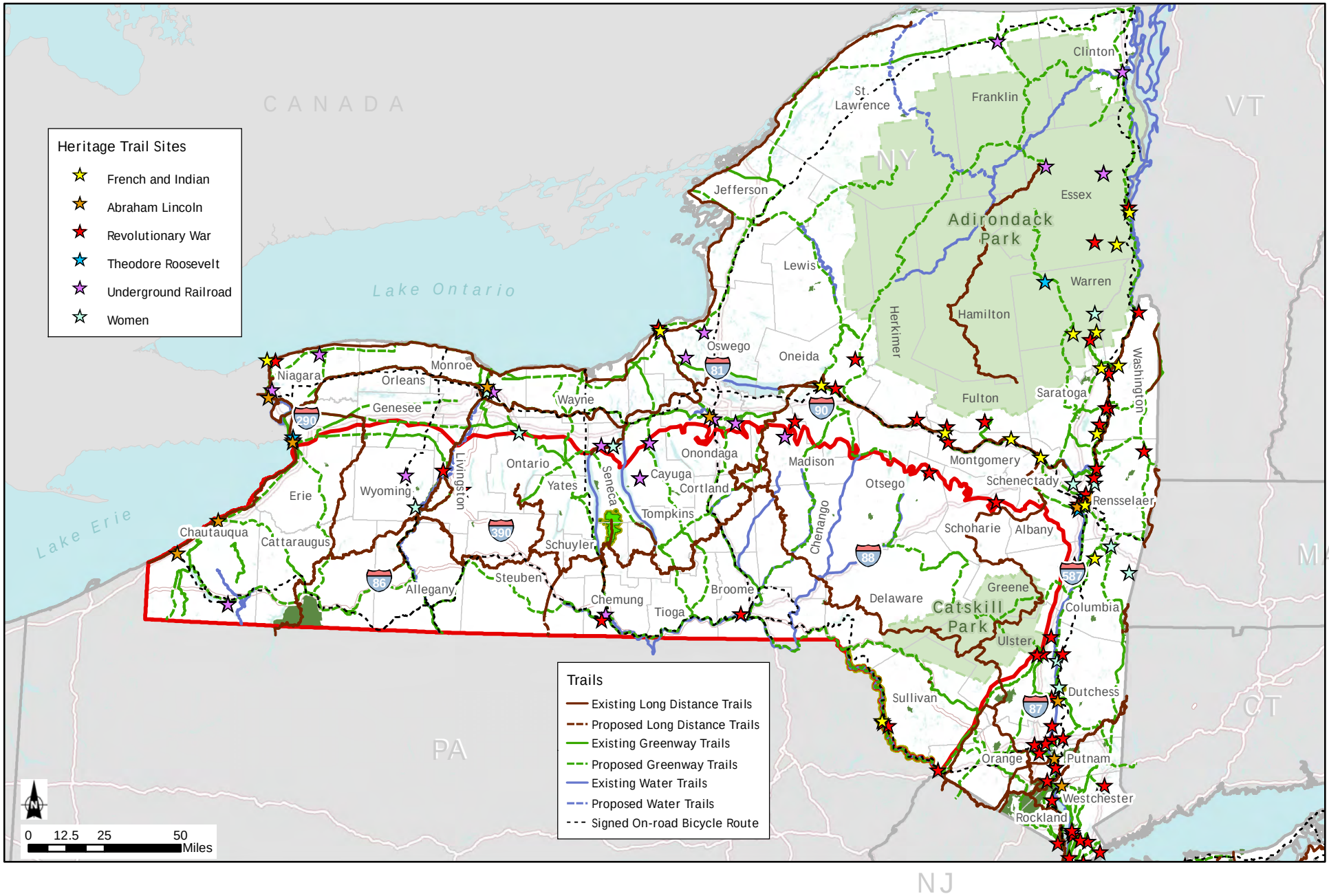
Properties included in the National Park System and areas defined as National Recreation Areas, Seashores and Forests contain natural, historic, cultural, and recreational resources of significance to the nation. Owned by the U.S. government and operated by various federal agencies, they are maintained for the public's use. At least five properties included in the National Park System are located in counties that are partially or entirely within the area underlain by the Marcellus and Utica Shales in New York: Women's Rights National Historic Park in Seneca County; Fort Stanwix National Monument in Oneida County; the North Country National Scenic Trail, which traverses New York State; Old Blenheim Covered Bridge in Schoharie County; and the Upper Delaware Scenic & Recreational River in Orange, Sullivan, and Delaware Counties (OPRHP 2008). One National Forest, the Finger Lakes National Forest in Seneca and Schuyler Counties, is located within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.12) (OPRHP 2008). No National Recreation Areas or National Seashores are located within the area underlain by the Marcellus and Utica Shales in New York (OPRHP 2008). The federally-owned National Park System properties and the National Forest may contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.

A state or federally designated trail, or one proposed for designation (16 U.S.C. Chapter 27 or equivalent)

New York State's natural and cultural resources provide for a broad range of land and water-based trails that offer multiple recreational experiences (Table 2.95). Each region of the state offers a unique setting and different opportunities for trails (OPRHP 2008). New York State breaks the existing system of trails into three general categories: primary trails that are of national, statewide, or regional significance and that are considered long-distance trails; secondary trails, which typically connect to a primary trail system but are generally within parks or open space areas; and stand-alone trails, which are trails of local significance that do not connect to a primary trail system. Stand-alone trails are generally loop trails, trails that connect to points of interest, or trails that provide short connections between parks, open spaces, historic sites and/or communities, or elements of a community (OPRHP 2008).

Additional state-designated trails include heritage trails, greenway trails, and/or water trails. Heritage trails are existing non-linear resources associated with historical movements or themes (OPRHP 2007, 2010). Greenway trails are existing and proposed multi-use trails located within linear corridors of open space that connect public places, connect people with nature, and protect areas for environmentally sustainable purposes that include recreation, conservation, and transportation (OPRHP 2007, 2010). Water trails, also known as blueways, are existing and proposed designated recreational water routes suitable for canoes, kayaks, and small motorized watercraft (OPRHP 2010).

One federally recognized trail, the North Country National Scenic Trail, traverses portions of the area underlain by the Marcellus and Utica Shales in New York. The North Country National Scenic Trail, an approximately 3,200-mile-long trail extending from eastern New York State to North Dakota, is administered by the NPS (NPS 2010a, 2010b). The portion of the trail in New York is included in the system of trails shown on Figure 2.12. National Scenic Trails are designated under Section 5 of the National Trails System Act and are defined as extended trails located to provide for maximum outdoor recreation potential and for the conservation and enjoyment of the nationally significant scenic, historic, natural, or cultural qualities of the areas though which they pass (NPS 2010a). A number of these types of trails are shown on Figure 2.12. All of these types of trails are likely to contain scenic or aesthetic areas that may be considered visual resources or visually sensitive



Boundary of Area of Interest for Visual Resources
County Boundary
State Boundary
Major Water Bodies
National Park System Properties
National Forest
State Park

Figure 2.12: Parks and Recreational Resources that May be Visually Sensitive

Source: ESRI, 2010; USGS, 2002; NYCSCIC, 2005; NPS, 2010; National Atlas US and USGS, 2010; OPRHP, 2011; NYSDOT, 2011

Table 2.95 - Select Trails Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

Name of Trail	Type of Trail
North County National Scenic Trail*	• Long-distance trail of national significance
Long Path*	• Long-distance trail of statewide significance
Finger Lakes Trail*	• Long-distance trail of statewide significance
Canalway Trail*	• Long-distance trail of statewide significance
Hudson River Valley Greenway Trail System*	• Long-distance trail of statewide significance
Hudson River Greenway Water Trail*	• Long-distance trail of statewide significance
Genesee Valley Greenway*	• Long-distance trail of statewide significance
The statewide Snowmobile Trail System*	• Long-distance trail of statewide significance
Conservation Trail*	• Long-distance hiking trail of regional significance
Letchworth Trail*	• Long-distance hiking trail of regional significance
Bristol Hills Trail*	• Long-distance hiking trail of regional significance
Link Trail*	• Long-distance hiking trail of regional significance
Shawangunk Ridge Trail	• Long-distance hiking trail of regional significance
Abraham Lincoln Heritage Trail	• State-designated Heritage Trail consisting of resources in Chautauqua, Onondaga, and Albany Counties
Women Heritage Trail	• State-designated Heritage Trail consisting of resources in Chautauqua, Wyoming, Ontario, Seneca, and Cayuga Counties
Underground Railroad Heritage Trail	• State-designated Heritage Trail consisting of resources in Wyoming, Chemung, Seneca, Cayuga, Onondaga, and Madison Counties
Revolutionary War Heritage Trail	• State-designated Heritage Trail consisting of resources in Chemung, Broome Madison, Otsego Schoharie, Sullivan and Orange Counties
French and Indian Heritage Trail	• State-designated Heritage Trail consisting of resources in Sullivan County
Catherine Valley Trail	• Multi-use trail located within linear corridors of open space in Chemung and Schuyler Counties
Catskill Scenic Trail	• Multi-use trail located within linear corridors of open space in Delaware County
Delaware & Hudson Canal Trail	• Multi-use trail located within linear corridors of open space in Sullivan and Ulster Counties
Erie Canalway Trail*	• Multi-use trail located within linear corridors of open space
Genesee Valley Greenway*	• Multi-use trail located within linear corridors of open space
Ontario Pathways Rail Trail	• Multi-use trail located within linear corridors of open space in Ontario County
Orange Heritage Trail	• Multi-use trail located within linear corridors of open space in Orange County
Pat McGee Trail	• Multi-use trail located within linear corridors of open space in Cattaraugus County
Wallkill Valley Rail Trail	• Multi-use trail located within linear corridors of open space in Ulster County
Marden Cobb Waterway Trail	• Recreational water route
Cayuga-Seneca Canal Trail, which is a component of the larger NYS Canalway Water Trail*	• Recreational water route
Chemung Basin River Trail*	• Recreational water route
Headwaters River Trail(s)*	• Recreational water route
Upper Delaware Scenic and Recreational River*	• Recreational water route
Proposed Triple Divide Water Trail*	• Proposed recreational water route

Sources: ESRI 2010; OPRHP 2007, 2010; NPS 2010a, 2010b.
* Trail traverses one or more counties

2.4.12.3Natural Areas

This section discusses natural areas that are considered visual resources per NYSDEC Program Policy DEP-00-2, including state forest preserve areas; state nature and historic preserves; state or national wild, scenic and recreational rivers (designated and potential); national wildlife refuges, state game refuges, and state wildlife management areas; and national natural landmarks (NYSDEC 2000). These natural areas often contain scenic areas and/or are developed partly because of their associated visual or aesthetic qualities.

The State Forest Preserve (NYS Constitution Article XIV)

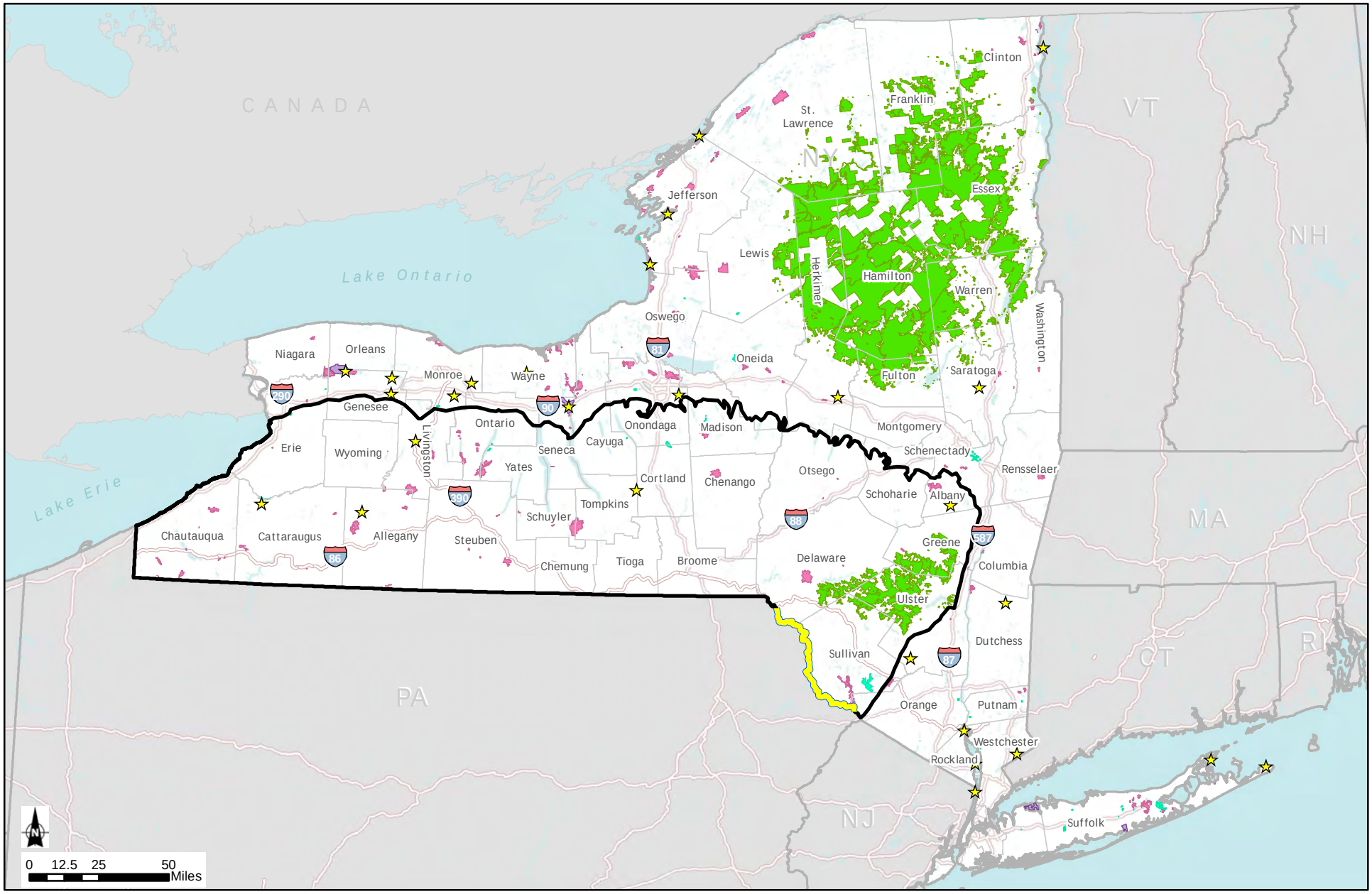
The State Forest Preserve consists of lands included in the Adirondack Forest Preserve (approximately 2.6 million acres) and the Catskill Forest Preserve (approximately 290,000 acres). These lands, which represent the majority of all state-owned property within the Adirondack and Catskill Parks, are protected as "forever wild" under Article XIV of the New York State Constitution. They are recognized as having exceptional scenic, recreational, and ecological value (NYSDEC 2011a, 2011b, 2011c).

The Adirondack Forest Preserve, located entirely within the Adirondack Park boundaries, is outside the area underlain by the Marcellus and Utica Shales in New York. The Catskill Forest Preserve, located entirely within the Catskill Park boundaries, is located within the eastern part of this area in portions of Delaware, Greene, Ulster, and Sullivan Counties (Figure 2.12). Lands included in the Catskill Forest Preserve are likely to contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.

State Nature and Historic Preserves (Section 4 of Article XIV of State Constitution)

State nature and historic preserves are parcels of land owned by the state that were acquired to protect the biological diversity of plants, animals, and natural communities, and which may provide a field laboratory for the observation of and education in these relationships. These areas may also provide for the protection of places of historical and natural interest, and may be used by the public for passive recreational pursuits that are compatible with protection of the ecological significance, historic features, and/or natural character of the areas designated as state nature and historic preserves (NYSDEC 2011d).

Eight state nature and historic preserves are located in the counties within the area underlain by the Marcellus and Utica Shales in New York (Table 2.96). These state nature and historic preserves may contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.



Major Water Bodies
County Boundary
State Boundary
Boundary of Area of Interest for Visual Resources
National Natural Landmark
National Wild and Scenic River
National Wildlife Refuge
State Forest Preserve
State Unique Area
State Wildlife Management Area

Figure 2.13: Natural Areas that May be Visually Sensitive

Source: ESRI, 2010; USGS, 2002; NYDEC, 2010; NPS, 2011; National Atlas US and USGS, 2010

Table 2.96 - State Nature and Historic Preserves in Counties Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of State Nature and Historic Preserves within County	Names of State Nature and Historic Preserves
Allegany	1	• Showy Lady Slipper Parcel (Town of New Hudson)
Cattaraugus	1	• Zoar Valley Unique Area (Towns of Otto and Persia)
Cortland	2	• Bog Brook (Towns of Southeast and Patterson) • Labrador Hollow (Town of Truxton)
Erie**	2	• Reinstein Woods (Town of Cheektowaga) • Zoar Valley Unique Area (Town of Collins)
Onondaga**	1	• Labrador Hollow (Town of Fabius)
Ontario**	1	• Squaw Island (Town of Canandaigua)
Yates	2	• Parish Gully (Town of Italy) • Clark Gully (Towns of Middlesex and Italy)
Total	**8*** **	

Sources: ESRI 2010; OPRHP 2008; NYSDEC 2011d.

* There are no State Nature and Historic Preserves within other counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.

*** Labrador Hollow is in two counties (Onondaga and Cortland); Zoar Valley Unique Area is in two counties (Cattaraugus and Erie).

Rivers designated as National or State Wild, Scenic or Recreational (16 U.S.C. Chapter 28, ECL 15-2701 et seq.)

National Wild, Scenic or Recreational Rivers are those rivers designated by Congress or the Secretary of the Interior in accordance with the Wild and Scenic Rivers Act of 1968. The purpose of such designation is to preserve those rivers with outstanding natural, cultural, and recreational values in a free-flowing condition for the enjoyment of present and future generations. Wild rivers are those rivers or sections of rivers that are free of impoundments and generally inaccessible except by trail, with watershed or shorelines essentially primitive and waters unpolluted. These represent vestiges of primitive America. Scenic rivers are those rivers or sections of rivers that are free of impoundments, with shorelines or a watershed still largely primitive and shorelines largely undeveloped, but accessible in places by roads. Recreational rivers are those rivers or sections of rivers that are readily accessible by road or railroad, that may have some development along their shorelines, and that may have undergone some impoundment or diversion in the past (National Wild and Scenic Rivers System 2011a).

A portion of only one river, the Delaware River (also known as the Upper Delaware Scenic and Recreational River), has been designated a National Wild and Scenic River in New York State (National Wild and Scenic Rivers System 2011b, 2011c; NPS 2010c). This portion of the Delaware River, located in Delaware County along the New York-Pennsylvania border, is within the area underlain by the Marcellus and Utica Shales in New York (see Table 2.97 and Figure 2.13). Designated in part for its scenic qualities, this portion of the Delaware River contains scenic areas that may be considered visual resources or visually sensitive.

A portion of one other water body in New York State, the East Branch of Fish Creek, located in Lewis County, was studied for its potential for inclusion in the National Wild and Scenic Rivers System (National Wild and Scenic Rivers System 2011d). This portion of Fish Creek is located in Oneida County, which is partially located within the area underlain by the Marcellus and Utica Shales in New York (Table 2.97).

Section 5(d) of the National Wild and Scenic Rivers Act of 1968 requires federal agencies to consider the effects of planned use and development on potential national wild and scenic river areas. In partial fulfillment of this requirement, the NPS has compiled and maintains a Nationwide Rivers Inventory (NRI), which is a register of river segments that potentially qualify as National Wild, Scenic or Recreational River areas (NPS 2008a).

In order to be listed on the NRI, a river must be free-flowing and possess one or more Outstanding Remarkable Values (ORVs). In order to be assessed as outstandingly remarkable, a river-related value must be a unique, rare, or exemplary feature that is significant at a comparative regional or national scale. Such values must be directly river-related: located in the river or on its immediate shorelands (generally within 0.25 mile on either side of the river); contribute substantially to the function of the river ecosystem; and/or owe their location or existence to the presence of the river. ORVs may involve values associated with scenery, recreation, geology, fish, wildlife, prehistory, history, cultural, or other values (e.g., hydrology, paleontology, or botany resources) (NPS 2008a).

Portions of 17 NRI-listed rivers or water bodies are located partially or entirely within the area underlain by the Marcellus and Utica Shales in New York (Table 2.97). Many of these rivers or water bodies have been designated in part for their scenic qualities, and all of these rivers or water bodies may contain scenic areas that may be considered visual resources or visually sensitive.

State-designated Wild, Scenic and Recreational Rivers are those rivers or portions of rivers of the state of New York protected by the state's Wild Scenic and Recreational Rivers Act. This act protects those rivers of the state that possess outstanding scenic, ecological, recreational, historic, and scientific values. Attributes of these rivers may include value derived from fish and wildlife and botanical resources, aesthetic quality, archaeological significance, and other cultural and historic features. State policy is to preserve designated rivers in a free-flowing condition, protecting them from improvident development and use, and to preserve the enjoyment and benefits derived from these rivers for present and future generations (NYSDEC 2011e).

Portions of two state-designated Wild, Scenic and Recreational Rivers - the Genesee River and the Upper Delaware River - flow within counties located partially or entirely within the area underlain by the Marcellus and Utica Shales in New York (Table 2.97). These rivers have been designated, in part, for their scenic qualities, and both of these rivers may contain scenic areas that may be considered visual resources or visually sensitive.

Table 2.97 - National and State Wild, Scenic and Recreational Rivers (designated or potential) Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Name of River or Water Body	Designation Status
Albany**	• Portion of Catskill Creek***	• Listed in NRI in 1982
Allegany	• Portions of Genesee River***	• Listed in NRI in 1982; updated in 1995 • Designated a State Wild, Scenic and Recreational River
Cattaraugus	• Portions of Allegheny River • Portions of Cattaraugus Creek*** • Portion of Conewango Creek ***	• Listed in NRI in 1982, updated in 1995 • Listed in NRI in 1982; updated in 1995 • Listed in NRI in 1982
Cayuga**	• Portion of Fall Creek***	• Designated a State Wild, Scenic and Recreational River
Chautauqua	• Portion of Cattaraugus Creek*** • Portion of Chautauqua Creek • Portion of Conewango Creek***	• Listed in NRI in 1982; updated in 1995 • Listed in 1982 • Listed in NRI in 1982
Chemung	• Portion of Chemung River	• Listed in NRI in 1982
Delaware	• Delaware River (Upper)*** • Portions of Delaware River, East Branch	• Designated a National Wild & Scenic River in 1978 • Listed in NRI in 1982 and 1995
Erie**	• Portions of Cattaraugus Creek***	• Listed in NRI in 1982; updated in 1995
Greene**	• Portion of Batavia Kill	• Listed in NRI in 1982
Livingston**	• Portions of Genesee River***	• Listed in NRI in 1982; updated in 1995 • Designated a State Wild, Scenic and Recreational River
Orange**	• Portion of Basher Kill ***	• Listed in NRI in 1995
Steuben	• Portion of Canisteo River • Portion of Cohocton River	• Listed in NRI in 1995 • Listed in NRI in 1995
Sullivan**	• Delaware River (Upper)*** • Portion of Basher Kill*** • Portion of Beaver Kill*** • Portions of Neversink River, including East and West Branches • Portion of Mongaup Creek	• Designated a National Wild and Scenic River in 1978 • Listed in NRI in 1995 • Listed in NRI in 1992; updated in 1995 • Listed in 1982 and 1995 • Listed in NRI in 1995
Tompkins	• Portion of Fall Creek***	• Designated a State Wild, Scenic and Recreational River
Ulster**	• Portion of Beaver Kill*** • Portion of Esopus Creek • Portions of Neversink River, including East and West Branches	• Listed in NRI in 1992; updated in 1995 • Listed in NRI in 1995 • Listed in 1982 and 1995
Wyoming	• Portions of Genesee River***	• Listed in NRI in 1982; updated in 1995 • Designated a State Wild, Scenic and Recreational River

Sources: ESRI 2010; NPS 2008a, 2009a, 2010c; OPRHP 2008; NYSDEC 2011f.

* There are no national or state Wild, Scenic and Recreational Rivers within other counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.

*** Portions of the Genesee River are in three counties (Allegany, Wyoming, and Livingston); portions of the Beaver Kill are in two counties (Ulster and Sullivan); portions of Cattaraugus Creek are in three counties (Erie, Cattaraugus, and Chautauqua); Conewango Creek is in two counties (Chautauqua and Cattaraugus); Basher Kill is in two counties (Orange and Sullivan); the Upper Delaware River is in two counties (Delaware and Sullivan); Fall Creek is in two counties (Cayuga and Tompkins).

National Wildlife Refuges (16 U.S.C. 668dd), State Game Refuges and State Wildlife Management Areas (ECL 11-2105)

National Wildlife Refuges (NWRs) are a network of lands and waters included in the National Wildlife Refuge system and managed by the U.S. Fish and Wildlife Service. These lands and waters are set aside for the conservation, management and, where appropriate, restoration of fish, wildlife, and plant resources and their habitats. In addition to the task of conserving wildlife, NWRs may also be managed for six wildlife-dependent recreational uses: hunting, fishing, wildlife observation, photography, and environmental education and interpretation. There are three NWRs in counties that are partially within the area underlain by the Marcellus and Utica Shales of New York: The Iroquois NWR in Genesee and Orleans Counties; the Montezuma NWR in Seneca and Wayne Counties; and the Shawangunk Grasslands NWR in Ulster County (USFWS 2011). However, none of the NWRs are located within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.13).

New York State's ECL (11-2105) defines state game refuges as lands set aside or established for the protection of wildlife and fish. Such lands remain game refuges until the state permits the taking of wildlife or fish within these lands. State Wildlife Management Areas (WMAs) are lands owned by New York State that have been acquired primarily for the production and use of wildlife, including research on wildlife species and habitat management. WMAs are under the control and management of the Department's DFWMR. While fishing, hunting and trapping are the most widely practiced recreational activities on many WMAs, most also provide opportunities for hiking, cross-country skiing, bird watching, or enjoying nature (NYSDEC 2011g).

There are 42 state game refuges or WMAs within the area underlain by the Marcellus and Utica Shales in New York (Table 2.98 and Figure 2.13). Many of the lands included in state game refuges or WMAs contain scenic areas that may be considered visual resources or visually sensitive.

Table 2.98 - State Game Refuges and State Wildlife Management Areas Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of State Game Refuges and WMAs	Name of State Game Refuges or WMA
Albany**	2	• Louise E. Keir WMA • Partridge Run WMA
Allegany	4	• Alma Pond • Genesee Valley WMA • Hanging Bog WMA • Keeney Swamp WMA
Cattaraugus	2	• Conewango Swamp WMA • Harwood Lake MUA
Chautauqua	8	• Alder Bottom WMA • Canadaway Creek WMA • Clay Pond WMA • Hartson Swamp WMA • Jacquins Pond WMA • Kabob WMA • Tom's Point WMA • Watts Flats WMA
Chenango	1	• Pharsalia WMA
Delaware	2	• Bear Spring Mountain WMA • Wolf Hollow WMA
Erie**	1	• Hampton Brook Woods WMA
Greene**	1	• Vinegar Hill WMA
Livingston**	2	• Conesus Inlet WMA • Rattlesnake Hill WMA
Madison**	1	• Tioughnioga WMA
Ontario**	2	• Honeoye Creek WMA • Stid Hill MUA
Orange**	1	• Cherry Island WMA
Otsego**	2	• Crumhorn Mountain WMA • Hooker Mountain WMA
Schoharie**	1	• Franklinton Vlaie WMA
Schuyler	2	• Catharine Creek WMA • Waneta-Lamoka WMA
Seneca**	1	• Willard WMA
Steuben	4	• Cold Brook WMA • Erwin WMA • Helmer Creek WMA • West Cameron WMA
Sullivan**	2	• Bashakill WMA • Mongaup Valley WMA
Tompkins	1	• Connecticut Hill WMA
Wyoming	1	• Silver Lake Outlet WMA
Yates	1	• High Tor WMA
Total	**42**	

Source: ESRI 2010; NYSDEC 2011g, 2011h; USFWS 2011.

* No other NWRs or state game refuges or wildlife management areas in New York State are located within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York State.

National Natural Landmarks [36 CFR Part 62]

National Natural Landmarks (NNLs) are sites that contain outstanding biological and/or geological resources, regardless of land ownership, and are selected for their outstanding condition, illustrative value, rarity, diversity, and value to science and education. NNL sites are designated by the Secretary of the Interior, with landowner concurrence (NPS 2008b, 2009b, 2011e). Five NNLs are located within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.13 and Table 2.99). These NNLs are a combination of unique ecological settings such as bogs or marshes and geological features (NPS 2011f). They are likely to contain aesthetic areas that may be considered visual resources or visually sensitive.

Table 2.99 - National Natural Landmarks Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Name of National Natural Landmark	Description
Albany	• Bear Swamp	• Designated in 1973 • Low, swampy woodland with relict stands of great laurel
Allegany	• Moss Lake Bog	• Designated in 1973 • Post-glacial sphagnum bog in a small kettle lake
Cattaraugus	• Deer Lick Nature Sanctuary	• Designated in 1967 • Gorge and mature northern hardwood forest
Livingston	• Fall Brook Gorge	• Designated in 1970 • Gorge exposing Upper and Middle Devonian Age geological strata with fossil remains and a waterfall • Series of ecological communities developed in response to sharply contrasting microclimates
Tompkins	• McLean Bogs	• Designated in 1973 • Two spring-fed bogs, one acidic and one alkaline • Rare plant species and one of the best examples of a northern deciduous forest in New York

Sources: ESRI 2010; NPS 2011f.

* None of the other NNLs in New York State, including those in Genesee, Onondaga, Seneca, and Ulster Counties, are located within the area underlain by the Marcellus and Utica Shales in New York

2.4.12.4 Additional Designated Scenic or Other Areas

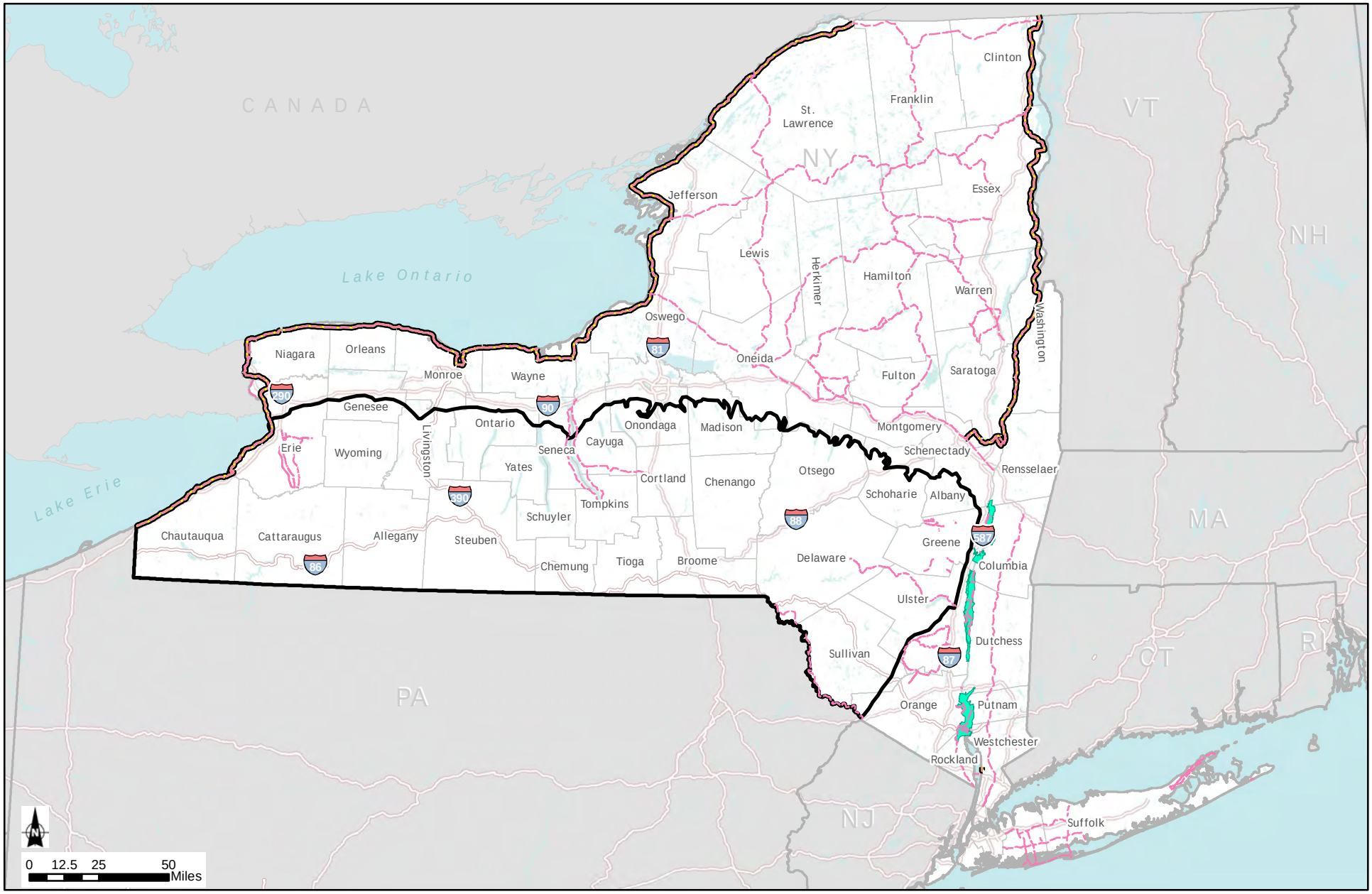
This section discusses additional designated scenic or other areas that are considered visual resources or visually sensitive per NYSDEC Program Policy DEP-00-2, including sites, areas, lakes, reservoirs, or highways designated or eligible for designation as scenic; scenic areas of statewide significance; Adirondack Park scenic vistas; Palisades Park system components; and national heritage areas (NYSDEC 2000). These areas often contain scenic areas and/or are developed partly because of their associated visual or aesthetic qualities.

A site, area, lake, reservoir, or highway designated or eligible for designation as scenic (ECL Article 49 or DOT equivalent and APA), Designated State Highway Roadside (Article 49 Scenic Road)

Resources designated or eligible for designation as scenic can include sites, areas, lakes, reservoirs, or highways. Many of these types of resources are discussed in other areas of the Visual Resources section. This subsection focuses on designated scenic roads.

New York State Scenic Byways are transportation corridors that are of particular statewide interest. They are representative of a region's scenic, recreational, cultural, natural, historic, or archaeological significance (NYSDOT 1999-2011). There are nine state-designated and three proposed scenic byways within the area underlain by the Marcellus and Utica Shales in New York (see Table 2.100). The locations of many of these are shown on Figure 2.14. There are also a number of state-designated scenic roads in New York (NYSDOT 1999-2011). While there are 28 roads in portions of Orange and Greene Counties, these are all located outside the area underlain by the Marcellus and Utica Shales in New York.

The Great Lakes Seaway Trail, one of the state-designated scenic byways, is also a designated National Scenic Byway (Table 2.100 and Figure 2.14). The National Scenic Byways Program is managed by the U.S. Department of Transportation, Federal Highway Administration. National Scenic Byways are roads that are recognized based on one or more archaeological, cultural, historic, natural, recreational, and scenic qualities (USDOT 2011). State and national scenic byways and roads are resources designated specifically for scenic or aesthetic areas or qualities and which would be considered visual resources or visually sensitive.



Major Water Bodies
County Boundary
State Boundary
Boundary of Area of Interest for Visual Resources
State Scenic Byway
National Scenic Byway
Scenic Areas of Statewide Significance

Figure 2.14: Additional Designated Scenic or other Areas that May be Visually Sensitive

Source: ESRI, 2010; USGS, 2002; NYDEC, 2010; NPS, 2011; National Atlas US and USGS, 2010

Table 2.100 - Designated and Proposed National and State Scenic Byways, Highways, and Roads Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

Name	Description
Great Lakes Seaway Trail	• National Scenic Byway • State-designated scenic byway • Great Lakes/Canadian border • Scenic, recreational, historic, and natural themes
Western New York Southtowns Scenic Byway	• State-designated scenic byway • Lake Erie • Scenic, historical, natural, recreational themes
Cayuga Lake Scenic Byway	• State-designated scenic byway • Finger Lakes region of New York State • Scenic and recreational themes
Scenic Route 90	• State-designated scenic byway • Finger Lakes region of New York State • Scenic, recreational, natural, and historic themes
Route 417/36 Scenic Byway	• State-designated scenic byway • Finger Lakes region of New York State • Scenic, recreational, natural, and historical themes
Seneca Lake, Hector and Lodi Scenic Byway	• State-designated scenic byway • Finger Lakes region of New York State • Scenic, historical, recreational, and natural themes
Route Twenty Scenic Byway (U.S. Route 20)	• State-designated scenic byway • Central New York State • Scenic, natural and historic themes
Shawangunk Mountains Scenic Byway*	• State-designated scenic byway • Shawangunk Mountains • Scenic and natural themes
Route 28 Central Catskills Scenic Byway	• Proposed scenic byway • Catskill Mountains
Mountain Cloves Scenic Byway	• Proposed scenic byway • Catskill Mountains
Durham Valley Scenic Byway	• Proposed scenic byway • Catskill Mountains
Upper Delaware Scenic Byway	• State-designated scenic byway • Delaware River Valley • Scenic, natural, historic, and recreational themes

Sources: NYSDOT 1999-2011; USDOT 2011; Catskill Center for Conservation and Development 2011; Durham Valley Scenic Byway Corridor Coordinating Committee (undated); Mountain Cloves Scenic Byway Steering Committee 2011.

* Shawangunk Mountains Scenic Byway is adjacent to and immediately outside of the western edge of the area underlain by the Marcellus and Utica Shales in New York.

Scenic Areas of Statewide Significance (Article 42 of Executive Law)

Scenic Areas of Statewide Significance (SASS) are areas designated by the Department of State based on a scenic assessment program developed by the Division of Coastal Resources. This program identifies the scenic qualities of coastal landscapes, evaluates them against criteria for determining aesthetic significance, and recommends areas for designation. An SASS designation protects scenic landscapes through the review of projects requiring state or federal actions, including direct actions, permits, or funding (NYSDOS 2004).

Six areas within the Hudson River Valley coastal regions in Columbia, Greene, Dutchess, and Ulster Counties were designated as SASSs in 1993. All six of these areas are outside the area underlain by the Marcellus and Utica Shales in New York (Figure 2.14).

Adirondack Park Scenic Vistas (Adirondack Park Land Use and Development Map)

The Adirondack Park was created in 1892 by the State of New York and is the largest publicly protected area in the contiguous United States. The boundary of the Park encompasses approximately 6 million acres in northern New York State, including portions of Saint Lawrence, Franklin, Clinton, Lewis, Herkimer, Hamilton, Essex, Oneida, Fulton, Warren, Saratoga, and Washington Counties. Nearly half of the Adirondack Park is publicly-owned and belongs to the people of New York State; this public land is constitutionally protected to remain "forever wild" forest preserve (Adirondack Park Agency 2003). No Adirondack Park Scenic Vistas are located within the boundary of the area underlain by the Marcellus and Utica Shales in New York (State of New York 2001).

Palisades Park (Palisades Interstate Park Commission)

The Palisades are a unique geological feature consisting of cliffs extending from southeastern New York State to northwestern New Jersey. While there is no Palisades Park in New York State, there are a number of state, county, and town parks in Orange and Rockland Counties, New York, that are located along the Palisades, many of which are operated in conjunction with the Palisades Interstate Park Commission. These parks include: Bear Mountain Park, Blauvelt State Park, Bristol Beach Park, Buttermilk Falls County Park, Clausland Mountain County Park, Franny Reese State Park, Goosepond Mountain Park, Harriman Park, Haverstraw Park, High Tor State Park, Highland Lakes Park, Hook Mountain State Park, Lake Superior Park, Minnewaska

Preserve, Mountain View Nature County Park, Nyack Beach State Park, Rockland Lake State Park, Schunnemunk Ridge Park, Sean Hunter Ryan Memorial County Park, Sterling Forest Park, Storm King Mountain Park, Tackamack Town Park (North and South), and Tallman State Park (New York-New Jersey Trails Conference 1999-2011, Palisades Parks Conservancy 2003-2007). None of these parks are located within the area underlain by the Marcellus and Utica Shales in New York.

Bond Act Properties purchased under Exceptional Scenic Beauty or Open Space category

Bond Act Properties are properties purchased under the "Exceptional Scenic Beauty" or "Open Space" categories of the Environmental Bond Act of 1986. Properties included in the "Exceptional Scenic Beauty" category are defined as land forms, water bodies, geologic formations, and vegetation that possess significant scenic qualities or significantly contribute to scenic value. Properties included in the "Open Space" category are defined as open or natural land in or near urban or suburban areas necessary to serve the scenic or recreational needs thereof. Such properties are purchased by individual municipalities using grants from New York State; grants consist of moneys raised through the sale of environmental bonds. Municipalities can include cities; counties, towns, villages, and public benefit corporations; school districts or improvement districts within a city, county, town or village; or Indian tribes residing within New York state; or any combination thereof (FindLaw 2011).

The OPRHP's Open Space Conservation Plan identifies 38 regional priority conservation projects within the area underlain by the Marcellus and Utica Shales in New York (Table 2.101). These projects represent the unique and irreplaceable open-space resources that encompass exceptional ecological, wildlife, recreational, scenic, and historical values. They were identified as a result of extensive analysis of New York State's open-space conservation needs by nine Regional Advisory Committees, in consultation with NYSDEC and OPRHP (OPRHP 2009). If acquired, these projects would be considered Bond Act properties purchased under the Open Space category. Additional previous Bond Act Properties may be located throughout the counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York. Bond Act Properties purchased under the "Exceptional Scenic Beauty" or "Open Space" categories contain, or may contain, scenic or aesthetic qualities that may be considered visual resources or visually sensitive.

Table 2.101 - Recommended Open Space Conservation Projects Located in the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of Recommended Conservation Projects in County	Name of Recommended Conservation Project
Albany**	3	• Black Creek Marsh/Vly Swamp (Project 44) – expand protection of wetland complex • Five Rivers Environmental Education Center (Project 46) – protect Phillipinkill stream corridor to north and east of education center • Helderberg Escarpment (Project 48) – protect southern extent of this natural feature
Allegany	1	• Inland Lakes (Project 124)*** – protect undeveloped shoreline associated with wetlands and critical tributary habitat; protect water quality and important fish and wildlife habitat; and secure adequate public access for recreational opportunities
Cattaraugus	3	• Allegheny River Watershed (Project 117) – protect areas for conservation, recreational, educational, and public access purposes • Cattaraugus Creek and Tributaries (Project 119)*** – protect fisheries, recreational access, and unique geological areas • Significant wetlands (Project 127)*** – protect significant natural wetland communities and provide recreational, educational, and ecological enhancement opportunities (e.g., Keeney Swamp, Bird Swamp, and Hartland Swamp)
Cayuga**	2	• Carpenter Falls/Bear Swamp Corridor (Project 91)*** – protect water quality, preserve scenic resources, and expand the trail system in Bear Swamp State Forest • Summerhill Fen and Forest Complex (Project 102) – secure upland forests, wetlands, and adjacent upland buffers along Fall Creek that are recognized for biological and recreational significance
Chautauqua	5	• Cattaraugus Creek and Tributaries (Project 119)*** – protect fisheries, recreational access, and unique geological areas • Chautauqua Lake Access, Vistas, Shore Lands and Tributaries (Project 120) – secure public access for recreational fishing and boating, preserve undeveloped shoreline, and protect water quality • Lake Erie Tributary Gorges (Project 125)*** – acquire public access to various gorges along tributaries to Lake Erie • Trails and Trailways (Project 126) – protect existing trail corridors and acquire new corridor for trails • Inland Lakes (Project 124)*** – protect undeveloped shoreline associated with wetlands and critical tributary habitat; protect water quality and important fish and wildlife habitat; and secure adequate public access for recreational opportunities
Chemung	2	• Catharine Valley Complex (Project 108) – preserve unique geological and ecological areas and acquire land for recreational use of historic Chemung Canal towpath • Chemung River Greenbelt (Project 109)*** – expand and enhance significant recreational resources in a unique scenic landscape and protect important wildlife habitat
Chenango	1	• Genny Green Trail/Link Trail (Project 94) – acquire land for major trail connections
Cortland	1	• Develop a State Park in Cortland County (Project 92) – develop a state park

County Name*	Number of Recommended Conservation Projects in County	Name of Recommended Conservation Project
Delaware	3	• Catskill River and Road Corridors (Project 36)*** – protect lands that serve as riparian buffers, preserve or restore floodplain areas, protect scenic areas and vistas along principal road corridors and on visible ridgelines, protect flood-prone areas, and enhance public access and recreational opportunities in the following areas: Beaverkill/Willowemoc/Route 17 (future Interstate 86) Corridor; Delaware River Branches and Main Stem Corridors; Mongaup Valley WMA; and Route 28 Corridor (Blue Stone Wild Forest, Ticeteneyck Mt./Tonshi Mt./Kenozia Lake, Catskill Interpretive Center area, and Meade Hill/Fleischmann Mountain) • Upper Delaware Highlands (Project 42)*** – provide contiguous natural resource protection for one of key remaining ecological regions in the continental U.S through easements for forestland and farmlands and along the Upper Delaware Scenic Byway. • Susquehanna River Valley Corridor (Project 53)*** - protect areas within the Chesapeake Bay drainage basin for water quality, fisheries, public recreation, public access, birding, and agricultural conservation
Erie**	2	• Buffalo River Watershed (Project 118)*** – protect the Buffalo River corridor and three of its tributaries and improve access for recreational users • Lake Erie Tributary Gorges (Project 125)***– acquire public access to various gorges along tributaries to Lake Erie
Livingston**	2	• Genesee River Corridor (Project 107)*** – protect various habitats and landscapes along the Genesee River • Western Finger Lakes: Conesus, Hemlock, Canadice and Honeoye (Project 113)*** - protect Finger Lakes shorelines that are wholly or largely undeveloped
Madison**	2	• Nelson Swamp (Project 95) – reduce ownership fragmentation of swamp, protect biologically significant swamp, further management objective of perpetual protection, and enhance compatible public use opportunities • Central Leatherstocking – Mohawk Grasslands Area (Project 87)*** – multi-regional project for conservation of habitat for grassland birds (grasslands occur in portions of Schoharie, Otsego, Oneida, Madison, and Onondaga Counties)
Oneida**	1	• Central Leatherstocking – Mohawk Grasslands Area (Project 87)*** – multi-regional project for conservation of habitat for grassland birds (grasslands occur in portions of Schoharie, Otsego, Oneida, Madison and Onondaga Counties)
Onondaga**	2	• Camillus Valley/Nine Mile Creek (Project 90) – buffer important attributes of the Nine Mile Creek Valley from development and provide public waterway access • Carpenter Falls/Bear Swamp Corridor (Project 91)*** – protect water quality, preserve scenic resources, and expand the trail system in Bear Swamp State Forest
Ontario**	2	• Hi Tor/Bristol Hills (Project 110)*** – ensure that key tracts of land remain as open space in this area • Western Finger Lakes: Conesus, Hemlock, Canadice and Honeoye (Project 113)*** - protect Finger Lakes shorelines that are wholly or largely undeveloped • Wolf Gully (Project 114) – protect for its exceptional biological diversity
Orange**	1	• Catskill River and Road Corridors (Project 36)*** – protect lands that serve as riparian buffers, preserve or restore floodplain areas, protect scenic areas and vistas along principal road corridors and on visible ridgelines, protect flood-prone areas, and enhance public access and recreational opportunities in

County Name*	Number of Recommended Conservation Projects in County	Name of Recommended Conservation Project
		the following areas: Beaverkill/Willowemoc/Route 17 (future Interstate 86) Corridor; Delaware River Branches and Main-stem Corridors; Mongaup Valley WMA; and Route 28 Corridor (Blue Stone Wild Forest, Ticeteneyck Mt./Tonshi Mt./Kenozia Lake, Catskill Interpretive Center area and Meade Hill/Fleischmann Mountain)
Otsego**	2	• Susquehanna River Valley Corridor (Project 53)*** - protect areas within the Chesapeake Bay drainage basin for water quality, fisheries, public recreation, public access, birding and agricultural conservation • Central Leatherstocking – Mohawk Grasslands Area (Project 87)*** – multi-regional project for conservation of habitat for grassland birds (grasslands occur in portions of Schoharie, Otsego, Oneida, Madison, and Onondaga Counties)
Schoharie**	1	• Central Leatherstocking – Mohawk Grasslands Area (Project 87)*** – multi-regional project for conservation of habitat for grassland birds (grasslands occur in portions of Schoharie, Otsego, Oneida, Madison, and Onondaga Counties)
Seneca**	1	• Seneca Army Depot Conservation Area (Project 111) – protect a unique population of white deer
Steuben	1	• Chemung River Greenbelt (Project 109)*** – expand and enhance significant recreation resources in a unique scenic landscape and protect important wildlife habitat
Sullivan**	4	• Neversink Highlands (Project 28) – protect significant natural attractions and resources, hunting and fishing opportunities, and wildlife habitat in the following areas: Tomsco Falls, Neversink Gorge vicinity, Basha Kill vicinity and Harlen Swamp Wetland Complex • Catskill River and Road Corridors (Project 36)*** – protect lands that serve as riparian buffers, preserve or restore floodplain areas, protect scenic areas and vistas along principal road corridors and on visible ridgelines, protect flood-prone areas, and enhance public access and recreational opportunities in the following areas: Beaverkill/Willowemoc/Route 17 (future Interstate 86) Corridor; Delaware River Branches and Main-stem Corridors; Mongaup Valley WMA; and Route 28 Corridor (Blue Stone Wild Forest, Ticeteneyck Mt./Tonshi Mt./Kenozia Lake, Catskill Interpretive Center area and Meade Hill/Fleischmann Mountain) • New York City Watershed Lands (Project 39) – identify and protect high-priority sites on land that have potential for development, for forestry, or for fisheries and relatively large and/or link area already protected by private or public entities and/or allow for improved long-term management of land and water resources • Upper Delaware Highlands (Project 42)*** – provide contiguous natural resource projection for one of key remaining ecological regions in the continental U.S through easements for forestland and farmlands and along the Upper Delaware Scenic Byway
Tioga	2	• Two Rivers State Park (Project 103) – develop a state park • Emerald Necklace (Project 104) – consolidate existing state holdings while ensuring linkage between public land in the vicinity of Ithaca, conserve lands, and enhance recreational opportunities
Tompkins	2	• State Parks Greenbelt/Tompkins County (Project 101) – protect valuable open-space recreational resources between four state park facilities connected by the Black Diamond Trail Corridor • Finger Lakes Shorelines (Project 105) – preserve portions of the shoreline of the Finger Lakes for public access or wildlife in the following areas or projects: Finger Lakes Water Trails, Owasco Flats, Camp Barton, On Cayuga

County Name*	Number of Recommended Conservation Projects in County	Name of Recommended Conservation Project
		Lake, B&H Railroad property at the south end of Keuka Lake in Hammondsport, extending the eastern terminus of the Outlet Trail to the Seneca Lake shoreline at Dresden, and undeveloped shoreline on Seneca Lake
Ulster**	3	• Great Rondout Wetlands (Project 24) – protect several large wetlands in the following areas: Great Pacama Vly, Cedar Swamp and Beer Kill Wetlands/Cape Pond • Catskill River and Road Corridors (Project 36)*** – protect lands that serve as riparian buffers, preserve or restore floodplain areas, protect scenic areas and vistas along principal road corridors and on visible ridgelines, protect flood-prone areas, and enhance public access and recreational opportunities in the following areas: Beaverkill/Willowemoc/Route 17 (future Interstate 86) Corridor; Delaware River Branches and Main-stem Corridors; Mongaup Valley WMA; and Route 28 Corridor (Blue Stone Wild Forest, Ticeteneyck Mt./Tonshi Mt./Kenozia Lake, Catskill Interpretive Center area, and Meade Hill/Fleischmann Mountain) • Catskills Unfragmented Forest (Project 37) – securing additional large unfragmented areas of forestlands in the Catskill High Peaks areas, including the following sites : Overlook Mountain; Guardian Mountain; Indian Head Wilderness Consolidation; Balsam, Graham and Doubletop Mountains/Dry Brook Valley; Peekamoose Gorge; Frost Valley; Fir Brook/Round Pond/Black Bear Road Vicinity; West Shokan/Sampsonville Area Lands; Bearpen/Vly/Roundtop Mountains; Catskill Escarpment North and Windham High Peak; Rusk Mountain Wild Forest; Hunter West Kill Wilderness; and Catskill Mountain Heritage Trail
Wyoming	3	• Buffalo River Watershed (Project 118)*** – protect the Buffalo River corridor and three of its tributaries and improve access for recreational users • Inland Lakes (Project 124)*** – protect undeveloped shoreline associated with wetlands and critical tributary habitat; protect water quality and important fish and wildlife habitat; and secure adequate public access for recreational opportunities • Inland Lakes (Project 124)*** – protect undeveloped shoreline associated with wetlands and critical tributary habitat; protect water quality and important fish and wildlife habitat; and secure adequate public access for recreational opportunities
Yates	1	• Hi Tor/Bristol Hills (Project 110)*** – ensure that key tracts of land remain as open space in this area
Total	38***	

Source: OPRHP 2009.

* No other recommended conservation projects are located within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales.

*** Susquehanna River Valley Corridor (Project 53) is in two counties (Otsego and Delaware); Cattaraugus Creek and Tributaries (Project 119) is in two counties (Cattaraugus and Chautauqua); Carpenter Falls/Bear Swamp Corridor (Project 91) may be in two counties (Cayuga and Onondaga); Lake Erie Tributary Gorges (Project 125) may be in two counties (Chautauqua and Erie); Central Leatherstocking – Mohawk Grasslands Area (Project 87) may occur in multiple counties (Schoharie, Otsego, Oneida, Madison and Onondaga); Catskill River and Road Corridors (Project 36) may occur in multiple counties (Delaware, Sullivan, Orange and Ulster); Catskill River and Road Corridors (Project 36) may occur in two counties (Delaware and Sullivan); Buffalo River Watershed (Project 118) will occur in two counties (Erie and Wyoming); Genesee River Corridor (Project 107) may occur in multiple counties from the New York/Pennsylvania state line to Lake Ontario; Western Finger Lakes: Conesus, Hemlock, Canadice and Honeoye (Project 113) will occur in two counties (Livingston and Ontario); Chemung River Greenbelt (Project 109) will occur in two counties (Chemung and Steuben); Inland Lakes (Project 124) is in three counties (Allegany, Chautauqua, and Wyoming); Hi Tor/Bristol Hills (Project 110) is in two counties (Yates and Ontario); Significant wetlands (Project 127) may occur in numerous counties.

2.4.13 Noise[56]

2.4.13.1 Noise Fundamentals

Noise is defined as any unwanted sound. Sound is defined as any pressure variation that the human ear can detect. Humans can detect a wide range of sound pressures, but only the pressure variations occurring within a particular set of frequencies are experienced as sound. However, the acuity of human hearing is not the same at all frequencies. Humans are less sensitive to low frequencies than to mid-frequencies, and so noise measurements are often adjusted (or weighted) to account for human perception and sensitivities. The unit of noise measurement is a decibel (dB). The most common weighting scale used is the A-weighted scale, which was developed to allow sound-level meters to simulate the frequency sensitivity of human hearing. Sound levels measured using this weighting are noted as dBA (A-weighted decibels). ("A" indicates that the sound has been filtered to reduce the strength of very low and very high frequency sounds, much as the human ear does.) The A-weighted scale is logarithmic, so an increase of 10 dB actually represents a sound that is 10 times louder. However, humans do not perceive a 10-dBA increase as 10 times louder but as only twice as loud.

The following is typical of human responses to changes in noise level:

- A 3-dBA change is the threshold of change detectable by the human ear;
- A 5-dBA change is readily noticeable; and
- A 10-dBA change is perceived as a doubling (or halving) of noise level.

The decrease in sound level from any single noise source normally follows the "inverse square law." That is, sound pressure level (SPL) changes in inverse proportion to the square of the distance from the sound source. At distances greater than 50 feet from a sound source, every doubling of the distance produces a 6-dB reduction in the sound level. Therefore, a sound level of 70 dB at 50 feet would have a sound level of approximately 64 dB at 100 feet. At 200 feet, sound from the same source would be perceived at a level of approximately 58 dB.

[56] Subsection 2.4.13, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

The total sound pressure created by multiple sound sources does not create a mathematical additive effect. For example, two proximal noise sources that are 70 dBA each do not have a combined noise level of 140 dBA. In this case the combined noise level is 73 dBA. As the difference between the two sound levels is 0 dB, 3 dB are added to the sound level to compensate for the additive effects of the sound.

To characterize the average ambient noise ("noise") environment in a given area, noise level descriptors are commonly used. The Leq (sound level equivalent) is generally used to characterize the average sound energy that occurs during a relatively short period, such as an hour. The Ldn (day-night level) would be used for an entire 24-hour period. To account for peoples' greater sensitivity to sound during nighttime hours, the Ldn noise metric descriptor places a stronger emphasis on noise that occurs during nighttime hours (10 p.m. to 7 a.m.) by applying a 10-dB "penalty" to those hours. The Lmax refers to the maximum A-weighted noise level recorded for a single noise event during a given period.

Although both the sound power and sound pressure characteristic of sound share the same unit of measure, the decibel (dB), and the term "sound level" is commonly substituted for each, they have different properties. Sound power is the acoustical energy emitted by the sound source, and is an absolute value; it is not affected by the environment. The SPL is the varying difference, at a fixed point, between the pressure caused by a sound wave and atmospheric pressure. Sound pressure is what our ears hear and what sound level meters measure. The sound power level is always considerably higher than the sound pressure level near a source because it takes into account the effective radiating surface area of the source.

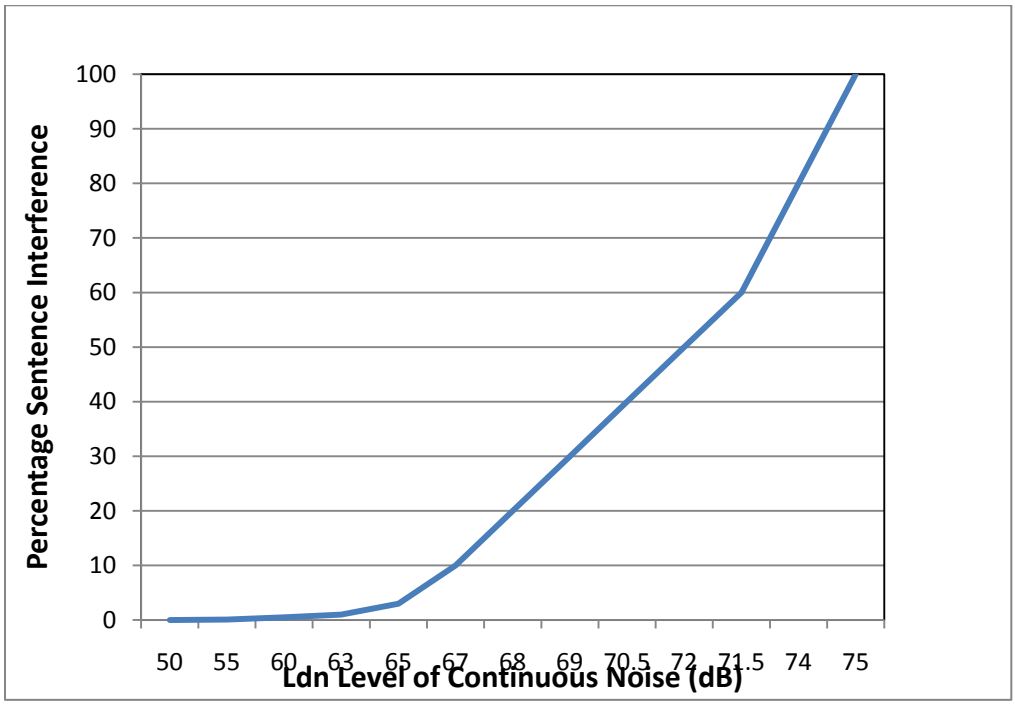
2.4.13.2 Common Noise Effects

Common noise effects include speech interference, sleep disturbance, and annoyance.

Speech Interference

The interference with speech comprehension is a masking process in which environmental noise curtails or prevents speech perception. The United States Environmental Protection Agency (USEPA) established the relationship between percent speech intelligibility and continuous noise level (USEPA 1974). This relationship is presented in Figure 2.15

Figure 2.15 - Level of Continuous Noise Causing Speech Interference (New August 2011)



Source: USEPA 1974.

Sleep Disturbance

Exposure to noise can produce disturbances of sleep in terms of difficulty to fall asleep, alterations of sleep pattern and depth, and awakening. It should be noted that the adverse effect of noise on sleep partly depends on the nature of the noise source, and there are considerable differences in individual reactions to the same noise. To avoid sleep disturbance, the World Health Organization (WHO) recommends an indoor level in bedrooms of 30 dBA for continuous noise and an Lmax of 45 dBA for single sound events (WHO 2000).

Annoyance

The capacity of noise to induce annoyance depends upon many of its physical characteristics, including its SPL and spectral characteristics, as well as the variations of these properties over time. Numerous studies have been conducted to assess community annoyance in response to transportation noise sources. A summary of community annoyance is presented in Table 2.102.

Table 2.102 - Effects of Noise on People (New August 2011)

Ldn (dBA)	Percent Annoyance	Average Community Reaction	General Community Attitude Towards Area
≥ 75	37	Very Severe	Noise is likely to be the most important of all adverse aspects of the community environment.
70	22	Severe	Noise is one of the most important adverse aspects of the community environment.
65	12	Significant	Noise is one of the important adverse aspects of the community environment.
60	7	Moderate	Noise may be considered an adverse aspect of the community environment.
≤ 55	3	Slight	Noise is considered no more important than various other environmental factors.

Source: Cowan 1994.

2.4.13.3 Noise Regulations and Guidance

Federal

In 1974 the USEPA published *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety* (USEPA 1974). This publication evaluates the effects of environmental noise with respect to health and safety. The document provides information for state and local governments to use in developing their own ambient noise standards. The USEPA has determined that in order to protect the public from activity interference and annoyance outdoors in residential areas, noise levels should not exceed an Ldn of 55 dBA (Table 2.103). The USEPA considers an Ldn of 55 dBA to be the maximum sound level that will not adversely affect public health and welfare by interfering with speech or other activities in outdoor areas.

Table 2.103 - Summary of Noise Levels Identified as Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety (New August 2011)

Effect	Level	Area
Hearing Loss	$Leq_{(24)}$ =< 70 dB	All areas
Outdoor activity interference and annoyance	Ldn =< 55 dB	Outdoors in residential areas and farms and other outdoor areas where people spend widely varying amounts of time and other places in which quiet is a basis for use
	$Leq_{(24)}$ =< 55 dB	Outdoor areas where people spend limited amounts of time, such as school yards, playgrounds, etc.
Indoor activity interference and annoyance	Ldn =< 45 dB $Leq_{(24)}$ =< 45 dB	Indoor residential areas Other indoor areas with human activities such as schools, etc.

Source: USEPA 1974.

New York State

The Department has issued Program Policy DEP-00-1, Assessing and Mitigating Noise Impacts, which is intended to provide direction to Department staff for the evaluation of sound levels and characteristics generated from proposed or existing facilities. Under this policy, in the review of an application for a permit, the Department is to evaluate the potential for adverse impacts of sound generated and emanating to receptors outside of the facility or property. When a sound level evaluation indicates that receptors may experience sound levels or characteristics that produce significant noise impacts or impairment of property use, the Department is to require the permittee or applicant to employ reasonable and necessary measures to either eliminate or mitigate adverse noise effects.

In the Department policy, noise is defined as any loud, discordant, or disagreeable sound or sounds. More commonly, in an environmental context, noise is defined simply as unwanted sound. The environmental effects of sound and human perceptions of sound can be described in terms of the following four characteristics:

1. SPL, or perceived loudness, as expressed in decibels (dB) or A-weighted decibel scale dBA, which is weighted towards those portions of the frequency spectrum, between 20 and 20,000 Hertz, to which the human ear is most sensitive. Both measure sound pressure in the atmosphere.

2. Frequency (perceived as pitch), the rate at which a sound source vibrates or makes the air vibrate.

3. Duration, i.e., recurring fluctuation in sound pressure or tone at an interval; sharp or startling noise at recurring interval; the temporal nature (continuous vs. intermittent) of sound.

4. Pure tone, which is comprised of a single frequency. Pure tones are relatively rare in nature but, if they do occur, they can be extremely annoying.

The initial evaluation for most facilities should determine the maximum amount of sound created at a single point in time by multiple activities for the proposed project. All facets of the construction and operation that produce noise should be included, such as land-clearing activities (chain saw and equipment operation), drilling, equipment operation for excavating, hauling or conveying materials, pile driving, steel work, material processing, and product storage and removal. Land clearing and construction may be only temporary noise at the site, whereas the ongoing operation of a facility would be considered permanent noise.

The Department Noise Guidelines state that increases ranging from 0 to 3 dB will have no appreciable effect on receptors, and that increases from 3 to 6 dB have potential for adverse noise impact only in cases where the most sensitive receptors are present. Sound pressure increases of more than 6 dB may require additional analysis of impact potential, depending on existing sound pressure levels and the character of surrounding land uses and receptors, and an increase of 6 dB(A) may cause complaints. Therefore, a cumulative increase in the total ambient sound level of 6 dBA or less is unlikely to constitute an adverse community impact.

To aid staff in its review of a potential noise impact, Program Policy DEP-00-1 identifies three major categories of noise sources:

- Fixed equipment or process operations,
- Mobile equipment or process operations, and
- Transport movements of products, raw material or waste.

2.4.13.4 Existing Noise Levels

The ambient sound level of a region is defined by the total noise generated, including sounds from natural and man-made sources. The magnitude and frequency of environmental noise may vary considerably over a day and throughout the week because of changing weather conditions and the

effects of seasonal vegetative cover. Table 2.104 presents SPLs that are characteristic for the land use described. Most of the high-volume hydraulic fracturing would occur in quiet rural areas where the noise levels are typically as low as 30 dBA, depending on weather conditions and natural noise sources.

Table 2.104 - Common Noise Levels (New August 2011)

Description	SPL (dBA)
Rural area at night	30
Quiet suburban area at night	40
Typical suburban area	50
Typical urban area	60

Source: Cowan 1994.
SPL = sound pressure level.

2.4.14 Transportation - Existing Environment[57]

This section presents a general overview of the vehicle and road classification system, major roadways and roadway use in the regional areas, and the primary funding sources for the roadway improvements. Although roadways would be the primary transportation system used to access well sites, railroads and airports may also be used to transport equipment and supplies. These other transportation modes are also briefly discussed.

2.4.14.1 Terminology and Definitions

The following terms are defined at the federal level to describe roadway classifications and vehicle classes and are used by transportation planners and engineers at the state and local levels.

Federal Functional Classification Codes

The federal functional classification (FC) codes group streets, roads, and highways into several classes based on the construction type and the type of service the roads provide. This discussion focuses on the roads prevalent in rural areas, where most of the horizontal drilling and high-volume hydraulic fracturing is assumed to occur.

[57] Subsection 2.4.14, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

Rural areas have five basic classifications of roads:

- FC01/FC02 - Principal Arterial (Interstate or Other);
- FC06 - Minor Arterial;
- FC07 – Major Collector;
- FC08 – Minor Collector; and
- FC09 – Local.

Typically, the higher the road classification, the higher the level of service a road can supply to vehicles, whether measured by vehicle class/weight or number of vehicle trips.

The arterial system of roadways provides the highest level of mobility at the highest speed, for long, uninterrupted travel. The construction of roads in the arterial system follows stringent guidelines, and high-grade materials are used. These roads can support more of the heavy vehicle truck traffic than smaller, local roads. The minor collectors (FC08) and, to a larger extent, the local roads (FC09) show signs of deterioration with an increase in heavy-truck traffic.

- Principal Arterial. The Principal Arterial categories are often divided into Principal Arterial - Interstate, and Principal Arterial - Other. Arterials generally are constructed according to higher design standards than other roads, often have multiple lanes traveling in the same direction, and have some degree of access control, such as on ramps.

The rural principal arterial highway network is an interstate and inter-county roadway that connects developed areas with an urban population typically greater than 50,000 people.

- Minor Arterial. A rural minor arterial highway is a roadway that is considered serving an urban area if it comes within 2 miles of the urban boundary.

Collector roadways provide a lower degree of mobility than arterials and are not designed for long-distance or high-speed travel. They typically consist of two-lane roads that collect and distribute traffic from the arterial system. They are divided into two categories in the rural setting - Major Collectors and Minor Collectors.

- Major Collector. Major Collectors provide service to any county seat not on an arterial route and can also connect or serve larger towns that are not provided services by their arterial roads.

- Minor Collector. Minor Collectors are roadways that are spaced consistently and proportional to population densities present in the rural community. They collect traffic from local roads and provide access to higher-level roads.

Local roads are the largest category of roads in terms of mileage in the road network. In rural areas, they include all public roads below the collector system, including basic residential and commercial roads.

There is an inverse relationship between the speeds and distances traveled on roads versus the actual existing mileage of the various road systems. The arterial systems account for higher average vehicle miles per trip (VMT), while local road systems account for the vast majority of actual roads (Table 2.105).

Table 2.105 - Guidelines on Extent of Rural Functional Systems (New August 2011)

System	Range (Average Vehicle Miles per Trip [VMT])	Miles of Road (percent)
Principal Arterial System	30-55	2-4
Principal Arterial plus Minor Arterial Road System	45-75	6-12[1]
Collector Road System	20-35	20-25
Local Road System	5-20	65-75

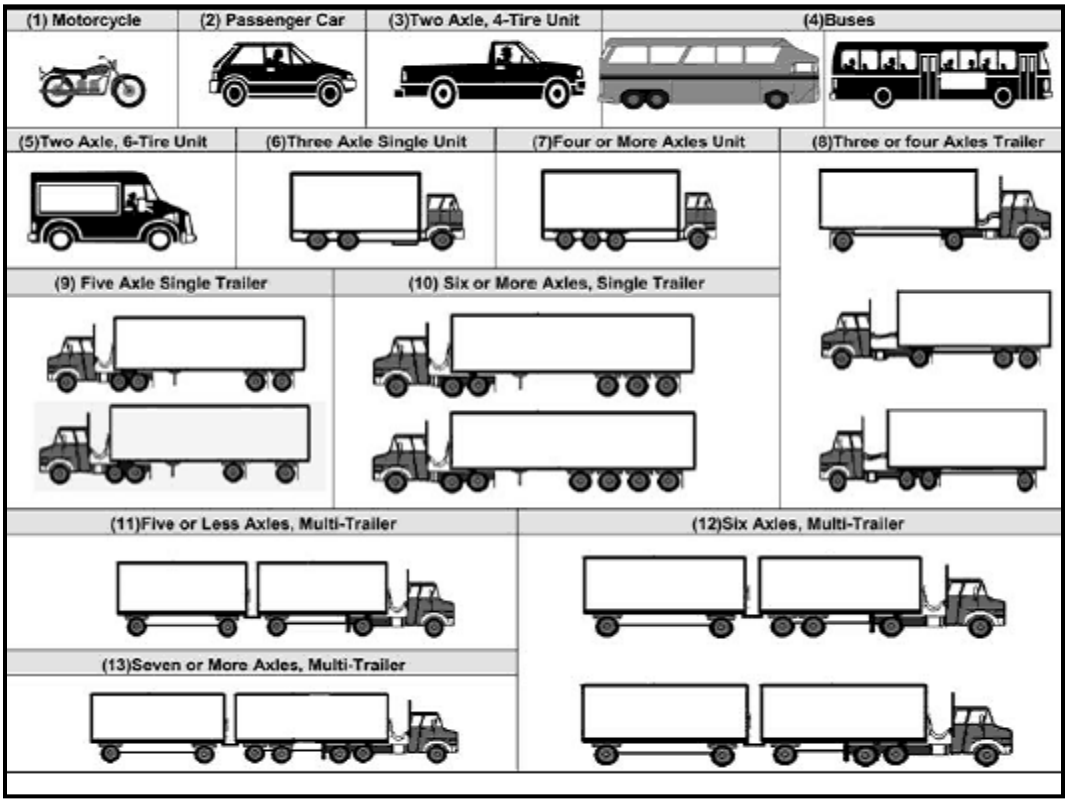
Source: FHWA 2011.
[1] Most states fall in the 7-10% range.

The FC codes have recently been updated; however, the codes presented in this section correspond to the codes used in data compilations that are currently available.

FHWA Vehicle Classes with Definitions

Figure 2.16 presents the Federal Highway Administration's (FHWA) vehicle class definitions (FHWA 2011). Table 2.106 provides descriptions of the 13 vehicle classes designated by the FHWA.

Figure 2.16 - FHWA Vehicle Classifications (New August 2011)



Source: Diamond Traffic Products 2011.

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
						Requires submission of a fluid disposal plan for flowback water which specifies quality, maintenance, and monitoring of piping and conveyances.	*7.1.6.3*			
						Requires application and pre-approval of POTWs proposing to dispose of flowback and production waters. Specifies application contents (e.g. headworks analysis, waste fluid characterization, regulatory limits) and demonstration that final discharges will fall within regulatory limits.	*7.1.8.1*			
						Requires SPDES coverage of any private wastewater treatment facility proposed to accept waste fluid.	*7.1.8.1*			
						Restates governance of EPA UIC permit over proposed injection well disposal. Notes site-specific SEQRA review for each injection well.	*7.1.8.2*			
Water resources (cont.)	Degradation/contamination of the NYC/unfiltered water supplies.					No well pads for high-volume hydraulic fracturing in the New York City or Syracuse watersheds or within a 4000' buffer of the watersheds.	*7.1.10*			
Floodplains	Contamination of surface waters from the release into the environment of chemical pollutants in a flood event.	*6.2*				No well pads or access roads for high-volume hydraulic fracturing permitted within 100-year floodplains.	*7.2*			
Freshwater Wetlands	Contamination of freshwater wetlands from accidental release of drilling or HF fluids, chemicals, or fuel.	*6.3*		*16.B.2.d*	*16-7..8*	For Department-regulated wetlands, makes permit approval dependent on site-specific SEQRA review and coverage under any necessary wetlands permits.	*7.3*			
						Specifies setbacks between fuel tanks and wetlands at a mandatory 500 feet.	*7.3*			
						Requires SPOTS 10 secondary containment for any fuel tank.	*7.3*			
						Requires a Wetlands Permit when project is w/in 100' of a freshwater wetland > 12.4 ac. in size or of unique local significance. Authorizes permit conditions on a case-by-case basis regarding location and timing of activities/facilities and replacement of lost wetland acreage.			*17.B.1.f*	*17-5*
Ecosystems and Wildlife	Degradation of local ecosystem from fragmentation of habitat	*6.4.1*				Requires operator to develop and employ Best Management Practices for surface disturbance to reduce habitat impacts.	*7.4.1*			
						Restricts operations during mating and migration seasons in certain habitats	*7.4.1*			

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
						Requires pre-drilling and post-completion animal and plant surveys when well pads are located in 150-acre or larger forest patches within Forest Focus Areas or 30-acre or larger grassland patches within Grassland Focus Areas.	*7.4.1*			
	Degradation of local ecosystem functions and native biological communities from the introduction of invasive species.	*6.4.1*				Requires operator diligence in exploiting accepted BMPs for removal and preventing introduction of invasive species.	*7.4.2.1*			
						Requires baseline surveying and reporting of project site for existence of invasive species.	*7.4.2.1*			
						Affords DEC the right to apply permit conditions for invasive species management when outside of the DRB and SRB.	*7.4.2.2*			
						Relies upon DRBC and SRBC protocols for aquatic invasive species management in their respective jurisdictions.	*7.4.2.2*			
Ecosystems and Wildlife (cont.)	Harm to local wildlife populations from the loss of habitat	*6.4.3*		*16.B.2.b*	*16-6..7*	Requires partial and final well pad reclamation.	*7.4.1*			
	Impacts to State-Owned Lands	*6.4.4*				No surface drilling allowed on specified State-owned lands.	*7.4.4*			
Air Quality	Degradation of Air Quality	*6.5*		*16.B.2.f*	*16-9..10*	Specifies minimum exhaust-stack heights, restrictions on public access, and sulfur content of fuel-oil.	*7.5.3.1*			
						Prohibits use of the BTEX class of compounds as additives in HVHF fluid surface impoundments.	*7.5.3.2*			
						Requires reporting of fracturing additives and public access restrictions.	*7.5.3.2*			
						Requires catalytic technology for production equipment.	*7.5.3.3*			
Greenhouse Gas Emissions	Emission of gases with Global Warming Potential due to natural gas well drilling and production.	*6.6*				Requires development of a GHG emissions impacts mitigation plan, requires development of a leak detection and repair program, and encourages participation in the USEPA's Natural Gas STAR program. Requires reduced emission completions where a pipeline is available.	*7.6.8*			
Naturally Occuring Radioactive Material (NORM)	Exposure of workers, the public, and the environment to harmful levels of radiation.	*6.8*				Outlines necessary monitoring work.	*7.8.2*			
						Requires NORM testing of discharged waste fluids and material in production tanks.	*7.8.2*			

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
Visual Impacts	Temporary new landscape features at well pads, new offsite facilities, congested appearance of campsites and staging areas, increase in specialized traffic.	*6.9*		*16.B.2.e*	*16-8*	Permit conditions would require operation consistent with a visual impacts mitigation plan. Site-specifc assessment could result in additional design and siting requirements.	*7.9*			
Noise	Temporary impacts but could occur on 24-hour basis. Potential 37-42 dB increase over quietest background at 2,000 feet during drilling and hydraulic fracturing. Increased traffic noise near well pad. Noise along approach and departure corridors from increased airplan service.	*6.10*		*16.B*	*16-2*	Operator must submit and adhere to a noise impacts mitigation plan. Site-specific assessment could result in specific mitigating permit conditions.	*7.10*		*17.B.1.b*	*17-4*
Transportation	Increased traffic on roadways; damage to local roads, bridges and other infrastructure; damage to state roads, bridges and other infrastructure; increased number of breakdowns and other accidents; risk of potentially hazardous spills; traffic impacts near rail centers.	*6.11*				Potential for road use agreements between operators and municipalities. Requirement to file a transportation plan that includes prposed routes and a road condition assessment. Site-specific assessment could result in additional traffic safety requirements, first responder emergency response training or avoidance of sensitive locations for trucks carrying hazardous materials.	*7.11*			
Socioeconomic & Community Character	Positive impacts on employment and income; increased economic activity; potential localized housing shortages; positive and negative impacts on state and government spending; increased tax revenues and production royalties; increased demand for local services; potential changes in the economic, demographic and social characteristics of affected communities that could be viewed as negative by some and positive by others.	*6.8 & 6.12*		*16.B.2.h*	*16-10..11*	This section will be updated after July 31, 2011.	*7.8 & 7.12*			

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New York State

DEC

Glossary

Updated August 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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Term	Definition
Access Road:	A road constructed to the wellsite that provides access during the drilling and operation of the well.
Accumulator:	The storage device for nitrogen pressurized hydraulic fluid, which is used in operating the blowout preventers.
AERMOD:	American Meteorological Society's and USEPA's Regulatory Model recommended by EPA for regulatory dispersion modeling.
AGC/SGC:	Annual Guideline Concentrations and Short-term Guideline Concentration defined in DAR-1 (Air Guide 1) procedures.
ALJ:	Administrative Law Judge.
Anaerobic:	Living or active in the absence of free oxygen.
Annular Space or Annulus:	Space between casing and the wellbore, or between the tubing and casing or wellbore, or between two strings of casing.
ANSS:	USGS's Advanced National Seismic System.
Anticline:	A fold with strata sloping downward on both sides from a common crest.
API:	American Petroleum Institute.
API Number:	A number referencing system designed by the American Petroleum Institute to identify wells; each state and county has a specific number code.
Aquifer:	A zone of permeable, water saturated rock material below the surface of the earth capable of producing significant quantities of water.
ARD (Acid Rock Drainage):	Refers to the outflow of acidic water from (usually abandoned) metal mines or coal mines. Acid rock drainage occurs naturally within some environments as part of the rock weathering process, usually within rocks containing an abundance of sulfide minerals.
AST:	Above-ground storage tank.
Bactericides:	Also known as a "Biocide." An additive that kills bacteria.
Barrel:	A volumetric unit of measurement equivalent to 42 U.S. gallons.
bbl:	Barrel.
bbl/yr:	Barrels per year.
Bcf:	Billion cubic feet. A unit of measurement for large volumes of gas.
Bentonite:	A natural clay, used as a cement or mud additive for its expansive characteristics and/or its tendency to not separate from water.
Berm:	A mound or wall of earth or sand.
Biocides:	See definition for "Bactericides".
Blending Unit or Blender:	The equipment used to prepare the slurries and gels commonly used in stimulation treatments.
Blooie Line:	Pipe that diverts fluids from the wellbore to a reserve pit.
Blowout:	An uncontrolled flow of gas, oil or water from a well, during drilling when high formation pressure is encountered.
BMP:	Best Management Practices.
BOD:	Biochemical (or biological) oxygen demand.

Term	Definition
BOP:	Blowout Preventer. A device attached immediately above the casing which can be closed and shut off the hole should a blowout occur.
Borehole:	See wellbore.
Breaker:	A chemical used to reduce the viscosity of a fluid (break it down) after the thickened fluid has finished the job it was designed for.
Brine Disposal Well:	A well (Class IID) for subsurface injection of associated produced brines from oil, gas and underground gas storage operations, or a well (Class V) for disposal of spent brine from geothermal and solution mining operations.
Brine:	A solution containing appreciable amounts of NaCl and/or other salts. Synonymous with salt water.
BTEX:	Benzene, Toluene, Ethylbenzene, and Xylene. These are all aromatic hydrocarbons.
BUD:	Beneficial Use Determination issued by NYSDEC's Division of Materials Management.
Buffer Zone:	An area designed to protect and separate an activity from things around it.
C&D:	Construction and demolition.
CAA:	Clean Air Act.
Cable Tool:	Equipment (rig) for cable-tool drilling consisting of a heavy metal bar sharpened to a chisel-like point and attached to a cable. The gravity impact of the heavy metal bar (bit) pulverizes the rock which is removed with a bailer.
Caliper Log:	A log that is used to check for any wellbore irregularities. It is run prior to primary cementing as a means of calculating the amount of cement needed. Also run in conjunction with other open-hole logs for log corrections.
Carbonate:	A salt of carbonic acid, CO_3^{-2}.
Carcinogen:	Cancer causing substance.
CAS Number:	Chemicals Abstract Service number, assigned by Chemical Abstracts Service, which is part of the American Chemical Society. The CAS registry is the most authoritative collection of disclosed chemical substance information, containing more than 48 million organic and inorganic substances and 61 million sequences.
Casing:	Steel pipe placed in a well.
Casing Shoe:	Reinforcing collar screwed onto the bottom of surface casing that guides the casing through the hole while absorbing the brunt of the shock.
Cation:	A positively charged ion.
CBS:	Chemical Bulk Storage.
CEA:	Critical Environmental Area.
Cement Bond Log:	A log used to evaluate the effectiveness of a primary cement job based on the different responses of sound waves in metal pipe and cement. It can also be used to locate channels in the cement.
Cement Sheath:	A protective covering around the casing, segregates the producing formation and prevents undesirable migration of fluid.
CFR:	Code of Federal Regulations.
cfs:	Cubic feet per second.

Term	Definition
CH_4:	Methane.
Chemical Additive:	A product composed of one or more chemical constituents that is added to a primary carrier fluid to modify its properties in order to form hydraulic fracturing fluid.
Chemical Constituent:	A discrete chemical with its own specific name or identity, such as a CAS Number, which is contained within an additive product.
Choke:	A device with an orifice installed in a line to restrict the flow of fluids.
Choke Manifold:	The arrangement of piping and special valves, called chokes, through which drilling mud is circulated when the blowout preventers are closed to control the pressures encountered during a kick.
Circulation:	The round trip made by the well fluids from the surface down the tubing, wellbore or casing, and then back to the surface.
Class GSB Water:	The best usage of Class GSB waters is as a receiving water for disposal of wastes. Class GSB waters are saline groundwaters that have a chloride concentration in excess of 1,000 milligrams per liter or a total dissolved solids concentration in excess of 2,000 milligrams per liter.
Clastic:	Rock consisting of fragments of rocks that have been transported from other places.
Clay Stabilizer/Clay Inhibitor:	A chemical additive used in stimulation treatments to prevent the migration and/or swelling of clay particles.
Closed Loop Drilling System:	A pitless drilling system where all drilling fluids and cuttings are contained at the surface within piping, separation equipment and tanks.
CO:	Carbon monoxide.
CO_2:	Carbon Dioxide.
CO_2e:	Carbon Dioxide equivalents.
COGCC:	Colorado Oil and Gas Conservation Commission.
Completion:	Preparation of a well for production after it has been drilled to the objective formation and in the case of a dry hole, preparation of a well for plugging and abandonment.
Compressive Strength:	Measure of the ability of a substance to withstand compression.
Compressor Stations:	Facilities which increase the pressure on natural gas to move it in pipelines or into storage.
Compulsory Integration:	New York's Environmental Conservation Law (Article 23, Titles 5 and 9 as amended by Chapter 386 of the Laws of 2005) gives all property owners the opportunity to recover or receive the gas beneath their property. To protect these "correlative rights," the Department of Environmental Conservation may establish spacing units whenever necessary. Compulsory integration is required when any owner in a spacing unit does not voluntarily integrate their interests with those of the unit operator. Compensation to the compulsory integrated interests will be established by a DEC Commissioner's Order after a public hearing.
Condensate:	Liquid hydrocarbons that were originally in the reservoir gas and are recovered by surface separation.
Conductor Hole:	The hole for conductor pipe or casing.
Conductor Pipe or Casing:	Large diameter casing that is usually the first string of casing in a well. Set or driven into the unconsolidated material where the well will be drilled to keep loose material from caving in. Usually relatively short in length.
Correlative Rights:	Rights of any mineral owner to recover resources that underlay their property.

Term	Definition
Corrosion Inhibitor:	A chemical substance that minimizes or prevents corrosion in metal equipment.
CRDPF:	Continuously Regenerating Diesel Particulate Filter.
Crosslinkers:	A compound, typically a metallic salt, mixed with a base-gel fluid, such as a guar-gel system, to create a viscous gel used in some stimulation or pipeline cleaning treatments. The crosslinker reacts with the multiple-strand polymer to couple the molecules, creating a fluid of high viscosity.
CT:	coiled tubing.
Cubic Foot:	Unit of measurement of the volume of gas contained in one cubic foot of space at a standard pressure (14.73 psi) and standard temperature (60° F).
Cuttings or Samples:	Chips of rock cut by the drill bit and brought to the surface by the drilling fluid. They indicate to the wellsite workers what kind of rocks are being penetrated and can also indicate the presence of oil or gas.
CWA:	Clean Water Act.
CWF:	Cold-Water Fishery (waters).
CWS:	Community water systems.
CZM:	Coastal Zone Management.
DAR:	Division of Air Resources in the NYS Department of Environmental Conservation.
DAR-1 (Air Guide-1):	Division of Air Resources program policy guidelines for the control of toxic air contaminants.
Dehydrator:	A device used to remove water and water vapors from gas.
Department:	New York State Department of Environmental Conservation.
De-sander:	A centrifugal device for removing sand from drilling fluid to prevent abrasion of the pumps. It may be operated mechanically or by a fast-moving stream of fluid inside a special cone-shaped vessel, in which case it is sometimes called a hydrocyclone.
De-silter:	A centrifugal device used to remove very fine particles, or silt, from drilling fluid.
Devonian Period:	Period of geologic time from 415 to 360 million years ago.
Diesel-Based Hydraulic Fracturing:	Hydraulic fracturing using diesel as the primary carrier.
Dip:	Angle of inclination from the horizontal.
Dipole Sonic Log:	A type of acoustic log that displays travel time of P-waves versus depth.
Disconformity:	A surface of erosion between parallel rock strata or a contact between two discordant structures (e.g., a dike emplaced within a layered sedimentary rock unit).
Disposal Well:	A well into which waste fluids can be injected deep underground for safe disposal.
DMM:	Division of Materials Management in the NYS Department of Environmental Conservation.
DMN:	Division of Mineral Resources in the NYS Department of Environmental Conservation.
DMR:	Division of Marine Resources in the NYS Department of Environmental Conservation.
Doghouse:	A small enclosure on the rig floor used as an office and/or as a storehouse for small objects. Also, any small building used as an office or for storage.
DOH:	(New York State) Department of Health.
DOW:	Division of Water in the NYS Department of Environmental Conservation.
DMV:	(New York State) Department of Motor Vehicles.

Term	Definition
DPS:	(New York State) Department of Public Service.
DRA:	Division of Regulatory Affairs in the NYS Department of Environmental Conservation.
DRBC:	Delaware River Basin Commission.
Drilling Fluid:	Mud, water, or air pumped down the drill string which acts as a lubricant for the bit and is used to carry rock cuttings back up the wellbore. It is also used for pressure control in the wellbore.
Drive Pipe:	See definition for "Conductor Casing".
Dry Hole:	Any well that does not produce oil or gas in commercial quantities.
DSHM:	Division of Solid and Hazardous Materials in the NYS Department of Environmental Conservation.
E&P:	Exploration and Production.
EAF:	Environmental Assessment Form.
ECL:	Environmental Conservation Law.
Ecosystem:	The system composed of interacting organisms and their environments.
EDR:	Electrodialysis Reversal.
Effluent:	Something that flows out, in particular a waste material such as an industrial discharge.
EIS:	Environmental Impact Statement.
EM&CP:	Environmental Management and Construction Plan.
EM&CS&P:	Environmental Management and Construction Standards and Practices.
Entrainment:	The condition of being drawn into something and transported with it, for example, gas bubbles in cement.
EO 41:	Executive Order 41.
EPA:	(U.S.) Environmental Protection Agency.
EPCRA:	Emergency Planning and Community Right to Know Act of 1986.
ERP:	Emergency Response Plan.
EUR:	Estimated ultimate recovery.
EV:	Exceptional Value (waters).
Evaporite:	Sedimentary rock or mineral deposits formed from the extensive or total evaporation of seawater.
FAA:	(U.S.) Federal Aviation Administration.
FAD:	Filtration Avoidance Determination.
Fault:	A fracture or fracture zone along which there has been displacement of the sides relative to each other.
Field:	The general area underlain by one or more pools.
Flare:	The burning of unwanted gas through a pipe.
Flocculant:	A chemical added to a fluid to cause unwanted particles, such as clay, to clump together for easier removal.
Floodplain:	Level land built up by stream deposition (past floods) that may be subject to future flooding.
Flowback Fluids:	Liquids produced following drilling and initial completion and clean-up of the well.
Flowmeter:	An instrument that measures fluid flow rates.
Flue Gas:	An exhaust gas coming out of a pipe or stack.
FMCSA:	Federal Motor Carrier Safety Administration.

Term	Definition
Foaming Agents:	An additive used to make foam in a drilling fluid.
Fold:	A bend in rock strata.
Footwall:	The mass of rock beneath a fault plane.
Formation:	A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.
Fossil:	A record of ancient life.
Fracing (pronounced “fracking”):	See definition for "Hydraulic Fracturing".
Freeboard:	The height above the recorded high-water mark of a structure associated with the water. In the case of pits, the extra depth left unused to prevent any chance of overflow.
Friction Reducers/Friction Reducing Agent:	Chemical additives which alter the hydraulic fracturing fluid allowing it to be pumped into the target formation at a higher rate & reduced pressure.
FTIR:	Fourier-transform Infrared.
Gamma Ray Log:	Log that records natural gamma radiation of the formations. Shales can be identified because of their high natural gamma radiation content.
Gas Gathering:	The collection and movement of raw gas from the wellhead to an acceptance point of a transportation pipeline.
Gas Meter:	An instrument for measuring and indicating, or recording, the volume of natural gas that has passed through it.
Gas-Water Separator:	A device used to separate undesirable water from gas produced from a well.
GEIS:	Generic Environmental Impact Statement.
Gelling Agents:	Polymers used to thicken fluid so that it can carry a significant amount of proppants into the formation.
Geomembrane:	Man-made polymeric membrane (flexible membrane) that is manufactured to be essentially impermeable and is used to build containment pits.
Geothermal Well:	A well drilled to explore for or produce heat from the subsurface.
GHG:	Greenhouse gas.
gpd:	Gallons per day.
gpm:	Gallons per minute.
GRI:	Gas Research Institute.
Groundwater:	Water in the subsurface below the water table. Groundwater is held in the pores of rocks, and can be connate, from meteoric sources, or associated with igneous intrusions.
Groundwater Hydrology:	The science of the occurrence, distribution, and movement of water below the surface of the earth.
Grout:	A concrete mixture placed into a well annulus from the surface; also, the process of emplacing such mixture.
GWP:	Global warming potential.
GWPC:	Ground Water Protection Council.
H_2SO_4:	Sulfuric acid.
HAPS:	Hazardous Air Pollutants as defined under the Clean Air Act.
Hardpan:	A hard impervious layer of soil composed chiefly of clay cemented by relatively insoluble materials.
HDPE:	High-density polyethylene. This plastic is resistant to most chemicals, insoluble in organic solvents, and has high impact and tensile strength.

Term	Definition
High-Volume Hydraulic Fracturing:	The stimulation of a well using 300,000 gallons or more of water as the base fluid in fracturing fluid.
HMTA:	Hazardous Material Transportation Act.
HMTUSA:	Hazardous Materials Transportation Uniform Safety Act.
Horizontal Drilling:	Deviation of the borehole from vertical so that the borehole penetrates a productive formation in a manner parallel to the formation.
Horizontal Leg:	The part of the wellbore that deviates significantly from the vertical; it may or may not be perfectly parallel with formational layering.
HQ:	High Quality (waters).
Hydraulic Conductivity:	A property of a soil or rock, that describes the ease with which water can move through pore spaces or fractures. It is dependent upon the intrinsic permeability of the material and on the degree of saturation.
Hydraulic Fracturing:	The act of pumping hydraulic fracturing fluid into a formation to increase its permeability.
Hydraulic Fracturing Fluid:	Fluid used to perform hydraulic fracturing; includes the primary carrier fluid and all applicable additives.
Hydrocarbons:	Organic compounds of hydrogen and carbon whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed of only two elements, hydrocarbons exist in a variety of compounds, because of the strong affinity of the carbon atom for other atoms and for itself. The smallest molecules of hydrocarbons are gaseous; the largest are solids. Petroleum is a mixture of many different hydrocarbons.
Hydrocyclone:	A device to classify, separate or sort particles in a liquid suspension based on the densities of the particles. A hydrocyclone may be used to separate solids from liquids or to separate liquids from different density.
Hydrogen Sulfide or H_2S:	A malodorous, toxic gas with the characteristic odor of rotten eggs.
ICE:	Internal Combustion Engines.
ICF:	ICF International, a consulting firm.
Igneous Rock:	Rock formed by solidification from a molten or partially molten state (magma).
Infill Wells:	Wells drilled between known producing wells to better exploit the reservoir.
Infrastructure:	The system of public works of a country, state, or region. It can also refer to the resources (as personnel, buildings, or equipment) required for an activity.
Injectate:	Injectate is any substance injected down a well.
Injection Well:	A well through which fluids are injected into an underground stratum to increase reservoir pressure and to displace oil. Also called an input well.
Injection Zone:	A geological formation, group of formations, or part of a formation that receives fluids through a well.
Intermediate Casing or String:	Casing set below the surface casing in deep holes where added support or control of the wellbore is needed. It goes between the surface casing and the conductor casing. In very deep wells, more than one string of intermediate casing may be used.
IOGA-NY:	Independent Oil and Gas Association of New York.
IOGCC:	Interstate Oil and Gas Compact Commission.
Iron Inhibitors:	Chemicals used to bind the metal ions and prevent a number of different types of problems that the metal can cause (for example, scaling problems in pipe).

Term	Definition
ITR:	Injection Timing Retard.
Joule-Thompson Effect:	Referring to the change in temperature observed when a gas expands while flowing through a restriction without any heat entering or leaving the system. The change may be positive or negative. The Joule-Thomson effect often causes a temperature decrease as gas flows through pores of a reservoir to the wellbore.
km:	Kilometer.
KML:	Keyhole Markup Language.
LCSN:	Lamont-Doherty Cooperative Seismographic Network.
LDAR:	Leak detection and repair.
LDCs:	Local Distribution Companies.
Limestone:	A sedimentary rock consisting chiefly of calcium carbonate ($CaCO_3$).
Lithologic:	Referring to the physical characteristics of rocks or sediment that can be determined with the human eye.
Log:	A systematic recording of data, such as a driller's log, mud log, electrical well log, or radioactivity log. Many different logs are run in wells to discern various characteristics of rock formations that the wellbore passes through.
Lost Circulation:	The quantities of drilling fluid lost to a formation, usually in cavernous, pressured, or coarsely permeable beds, evidenced by complete or partial failure of the mud to return to the surface as it is being circulated in the hole.
Lost Circulation Material:	Material put into fluids to block off the permeability of a lost circulation zone.
Lost Circulation Zone:	Formation that is so permeable or soluble that it diverts the flow of fluids from the well.
Low-Permeability Gas Reservoirs:	Gas bearing rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 0.10 milidarcies.
LPG:	Liquefied Petroleum Gas.
LWRP:	Local Waterfront Revitalization Program.
Manifold:	An arrangement of piping or valves designed to control, distribute and often monitor fluid flow.
Marcellus Well:	A well for which the operator designates the Marcellus Shale as the objective formation.
Mcf:	Thousand cubic feet.
MCL, MCLG:	Maximum Contaminant Level, Maximum Contaminant Level Goal.
md:	Millidarcy.
Methane:	Methane (CH_4) is a greenhouse gas that remains in the atmosphere for approximately 9-15 years. Methane is also a primary constituent of natural gas and an important energy source.
Microseisms (or microseismic events):	Small bursts of seismic energy generated by shear slippages along planes of weakness in the reservoir and surrounding layers which are induced by changes in stress and pore pressure around the hydraulic fracture. These microseisms are extremely small, and sensitive receiver systems are required.
Micro-annulus (plural is micro-annuli):	A small gap that can form between the casing or liner and the surrounding cement sheath, most commonly formed by variations in temperature or pressure during or after the cementing process.
mg/L:	milligrams per liter.

Term	Definition
Mineral Rights:	The ownership of the minerals under a given surface, with the right to enter and remove them. It may be separated from the surface ownership.
MMcf:	Million cubic feet.
MMcf/d:	Million cubic feet per day.
MOVES:	Motor Vehicle Emission Simulator.
mR/hr:	Milliroentgens per hour.
MSC:	Marcellus Shale Coalition.
MSDS:	Material Safety Data Sheet. A written or printed document which is prepared in accordance with 29 CFR 1910.1200(g).
MSGP:	Multi-Sector General Permit.
MSW:	Municipal solid waste.
Mudlogging (Unit):	Trailer located at the wellsite housing equipment and personnel to progressively analyze wellbore cuttings washed up from the borehole. A portion of the mud is diverted through a gas-detecting device.
NAAQS and AAQS:	National or State Ambient Air Quality Standards for criteria pollutants.
Native Gas:	Gas originally in place in an underground formation. Term is usually associated with gas storage.
NCWS:	Non-community water systems.
NESHAPs:	National Emission Standards for Hazardous Air Pollutants.
NFRM:	Natural Flow Regime Method.
NGPA:	Natural Gas Policy Act of 1978.
NH_3:	Ammonia.
NMHC:	Non-methane hydrocarbons.
NNSR:	Nonattainment New Source Review.
NOI:	Notice of Intent.
Noise Log:	A record of the sound vibrations in the wellbore caused by flowing liquid or gas. Used to determine fluid entry points or flow behind casing.
Non-Darcy Flow:	Fluid flow that deviates from Darcy's law, which assumes laminar flow in the formation. Non-Darcy flow is typically observed in high-rate gas wells when the flow converging to the wellbore reaches flow velocities exceeding the Reynolds number for laminar or Darcy flow, and results in turbulent flow.
Nonwetting Phase:	The pore space fluid which is not attached to the reservoir rock and thus has the greatest mobility.
N_2O:	Nitrous Oxide.
NO_2:	Nitrogen Dioxide.
NORM - Naturally Occurring Radioactive Materials:	Low-level radioactivity that can exist naturally in native materials, like some shales and may be present in drill cuttings and other wastes from a well.
Non-Indigenous:	Not having originated in and being produced, growing, living, or occurring naturally in a particular region or environment.
Normalized Pressure Integral Curve Analysis:	Another type of Decline or Type Curve Analysis (see).
NPDES:	National Pollutant Discharge Elimination System.

Term	Definition
NSCR:	Non-Selective Catalytic Reduction.
NSPS:	New Source Performance Standards.
NTNC:	Non- transient non-community.
NWS:	National Weather Service.
NYCDEP:	New York City Department of Environmental Protection.
NYCRR:	New York Codes of Rules and Regulations.
NYSDAM:	New York State Department of Agriculture and Markets.
NYSDOH:	New York State Department of Health.
NYSDOT:	New York State Department of Transportation.
NYSERDA:	New York State Energy Research and Development Authority.
O_3:	Ozone.
Operator:	Any person or organization in charge of the development of a lease or drilling and operation of a producing well.
OPRHP:	(NY State) Office of Parks, Recreation and Historic Preservation.
Ordovician Period:	Period of geologic time from 520 to 465 million years ago.
PADEP:	Pennsylvania Department of Environmental Protection.
Paleozoic Era:	Large block of geologic time from 570 to 225 million years ago; beginning marked by the appearance of abundant fossils. Most of the bedrock in New York State was formed (deposited) during the Paleozoic.
Parameter:	A characteristic of a model of a reservoir that may or may not vary with respect to position or with time. (e.g., porosity is a petrophysical parameter (or characteristic) that varies with position).
Partial Reclamation:	The reclamation of a well site following completion of a well and in the case of multi-well pad, completion of the last well on the multi-well pad. This includes the reclamation of pits, regarding of lands and the revegetation of lands outside the well pad.
Passby Flow Requirement:	A prescribed quantity of flow that must be allowed to pass an intake when withdrawal is occurring. Passby requirements also specify low- flow conditions during which no water can be withdrawn.
Pathogens:	A specific causative agent (as a virus or bacterium).
PBS:	Petroleum Bulk Storage.
PCC:	Pre-ignition Chamber Combustion.
Pennsylvanian Period:	Period of geologic time from 310 to 280 million years ago.
Percolation Test:	Test to determine at what rate fluids will pass through soil.
Perennial Stream:	A stream channel that has continuous flow in parts of its bed all year round during years of normal rainfall.
Perforate:	To make holes through the casing to allow the oil or gas to flow into the well or to squeeze cement behind the casing.
Perforation:	A hole created in the casing to achieve efficient communication between the reservoir and the wellbore.
Permeability:	A measure of a material's ability to allow passage of gas or liquid through pores, fractures, or other openings. The unit of measurement is the millidarcy.
Permeable:	Able to transmit gas or liquid through interconnected pores, fractures, or other openings.

Term	Definition
Petroleum:	In the broadest sense the term embraces the full spectrum of hydrocarbons (gaseous, liquid, and solid).
PHMSA:	Pipeline and Hazardous Materials Safety Administration.
PID:	Perforation Inflow Diagnostic.
Pipe Racks:	Horizontal supports for storing tubular goods.
Plat:	A map of land parcels; a drafted map of a site's location showing boundaries of adjoining parcels.
Plug Back:	To place cement in or near the bottom of a well to exclude bottom water, to sidetrack, or to produce from a formation higher in the well. Plugging back can also be accomplished with a mechanical plug set by wireline, tubing, or drill pipe.
Plugged and Abandoned:	(plug and abandon) To prepare a well to be closed permanently with cement plugs, usually after either logs determine there is insufficient hydrocarbon potential to complete the well, or after production operations have drained the reservoir.
PM10 and PM2.5:	Particulate matter with sizes of less than 10 and 2.5 microns, respectively.
Pneumatic:	Run by or using compressed air.
POC:	Principal Organic Contaminant.
Poisson's ratio:	An elastic constant that is a measure of the compressibility of material perpendicular to applied stress, or the ratio of latitudinal to longitudinal strain. Named for French mathematician Simeon Poisson (1781 to 1840).
Polymer:	Chemical compound of unusually high molecular weight composed of numerous repeated, linked molecular units.
Pool:	An underground reservoir containing a common accumulation of oil and/or gas. Each zone of a structure which is completely separated from any other zone in the same structure is a pool.
Porosity:	Volume of pore space expressed as a percent of the total bulk volume of the rock.
Potable Fresh Water:	Suitable for drinking by humans and containing less than 250 ppm of sodium chloride or 1,000 ppm TDS.
POTW:	Publicly Owned Treatment Works.
ppb:	Parts per billion.
ppm:	Parts per million.
Precambrian Era:	Very large block of geologic time spanning from Earth's formation to the 4,500 to 570 million years ago.
Pressure Buildup Test:	An analysis of data obtained from measurements of the bottomhole pressure in a well that is shut-in after a flow period. The profile created on a plot of pressure against time is used with mathematical reservoir models to assess the extent and characteristics of the reservoir and the near-wellbore area.
Primary Aquifer:	A highly productive aquifer presently being utilized as a source of water supply by a major municipal supply system.
Primary Carrier Fluid:	The base fluid, such as water, into which additives are mixed to form the hydraulic fracturing fluid which transports proppant.
Primary Production:	Production of a reservoir by natural energy in the reservoir.
Principal Aquifer:	An aquifer known to be highly productive or whose geology suggests abundant potential water supply, but which is not intensively used as a source of water supply by a major municipal system.

Term	Definition
Principal Stresses:	Forces per unit area acting on the external surface of a solid body.
Product:	A hydraulic fracturing fluid additive that is manufactured using precise amounts of specific chemical constituents and is assigned a commercial name under which the substance is sold or utilized.
Production Casing:	Casing set above or through the producing zone through which the well produces.
Production Brine:	Liquids co-produced during oil and gas wells production.
Proppant or Propping Agent:	A granular substance (sand grains, aluminum pellets, or other material) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a fracture treatment.
PSC:	Public Service Commission.
PSD:	Prevention of Significant Deterioration defined in the Clean Air Act.
PSI:	Pounds per square inch.
PSIG:	Pounds per Square Inch Gauge.
PSL:	Public Service Law.
Public Water Supply:	Either a community or non-community well system which provides piped water to the public for human consumption if the system has a minimum of five (5) service connections, or regularly serves a minimum average of 25 individuals per day at least 60 days per year.
PTE:	Potential to Emit.
Pump and Plug Method:	A technique for placing cement plugs at appropriate intervals.
PVC:	Polyvinylchloride; a durable petroleum derived plastic.
RACT:	Reasonably Available Control Technology.
Radial Cement Bond Log:	A record of sonic amplitudes derived from acoustic signals passing along the well casing. Used to evaluate cement-to-pipe and cement-to-formation bonding.
RCRA:	Resource Conservation and Recovery Act.
Real Property:	Includes mineral claims, surface and water rights.
REC:	Reduced Emissions Completion.
Reclaimed:	(Reclamation) Rehabilitation of a disturbed area to make it acceptable for designated uses. This normally involves regrading, replacement of topsoil, re-vegetation, and other work necessary to restore it.
Remediation:	The removal of pollution or contaminants from the environmental media such as soil, groundwater, or surface water.
Reserve pit:	A mud pit in which a supply of drilling fluid has been stored. Also, a waste pit, usually an excavated, earthen-walled pit. In NY it is required to be lined with plastic to prevent soil contamination.
Reservoir (oil or gas):	A subsurface, porous, permeable or naturally fractured rock body in which oil or gas has accumulated. A gas and production is only gas plus fresh water that condenses from the flow stream reservoir. In a gas condensate reservoir, the hydrocarbons may exist as a gas, but, when brought to the surface, some of the heavier hydrocarbons condense and become a liquid.
Reservoir (water):	Any man-made structure used to supply fresh water to the public.
Reservoir Rock:	A rock that may contain oil or gas in appreciable quantity and through which petroleum may migrate.

Term	Definition
RO:	Reverse Osmosis.
Rotary Rig:	A derrick equipped with rotary equipment where a well is drilled using rotational movement.
Royalty:	The landowner's share of the value of oil and gas produced.
Run-Off:	The portion of precipitation on land that ultimately reaches streams sometimes with dissolved or suspended material.
Sandstone:	A variously colored sedimentary rock composed chiefly of sandlike quartz grains cemented by lime, silica or other materials.
SAPA:	State Administrative Procedures Act.
Scale Inhibitor:	A chemical substance which prevents the accumulation of a mineral deposit (for example, calcium carbonate) that precipitates out of water and adheres to the inside of pipes, heaters, and other equipment.
SCR:	Selective Catalytic Reduction.
SDWA:	Safe Drinking Water Act.
SDWIS:	Safe Drinking Water Information System.
Sedimentary:	Rocks formed from sediment transported from their source and deposited in water or by precipitation from solution or from secretions of organisms.
Sedimentation Control:	(sedimentation) The process of separation of the components of a cement slurry during which the solids settle. Sedimentation is one of the characterizations used to define slurry stability.
Seep:	Natural leakage of gas or oil at the earth's surface.
SEIS:	Supplemental Environmental Impact Statement.
Seismic:	Related to earth vibrations produced naturally or artificially.
Separator:	Tank used to physically separate the oil, gas, and water produced simultaneously from a well.
SEQR:	Reference to the regulatory program or type of review done under SEQRA.
SEQRA:	State Environmental Quality Review Act.
Setback:	Minimum distance required between a well operation and other zones, boundaries, or objects such as highways, wetlands, streams, or houses.
SGC/AGC:	Short-term Guideline Concentration and Annual Guideline Concentrations defined in DAR-1 (Air Guide 1) procedures.
SGEIS:	Supplemental Generic Environmental Impact Statement.
Shale:	A thinly laminated claystone, siltstone or mud stone.
Shale Shaker:	A series of trays with sieves or screens that vibrate to remove cuttings from circulating fluid in rotary drilling operations. The size of the openings in the sieve is selected to match the size of the solids in the drilling fluid and the anticipated size of cuttings. Also called a shaker.
Shear Wave (S-wave):	Elastic body wave in which particles oscillate perpendicular to the direction in which the wave propagates. S-waves, or shear waves, travel more slowly than P-waves and cannot travel through fluids. Interpretation of S-waves can help determine rock properties.
Short Ton:	20 short hundred weight, 2,000 pounds.

Term	Definition
Show:	Small quantity of oil or gas, not enough for commercial production.
Shut In (Verb):	To close the valves at the wellhead to keep the well from flowing or to stop producing a well.
Shut-In (Adjective):	The state of a well which has been shut-in.
SI:	Spark Ignition.
Significant Habitats:	Areas which provide one or more of the key factors required for survival, variety or abundance of wildlife, and/or for human recreation associated with such wildlife.
SILs:	Significant Impact Levels for criteria pollutants.
Siltation:	The build-up of silt in a stream or lake as a result of activity that disturbs the streambed, bank, or surrounding land.
Siltstone:	Rock in which the constituent particles are predominantly silt size.
Silurian Period:	Period of geologic time from 405 to 415 million years ago.
SIP	State Implementation Plan
Slickwater Fracturing (or slick-water):	A type of hydraulic fracturing which utilizes water-based fracturing fluid mixed with a friction reducing agent & other chemical additives. The fluid is typically 98% fresh water & sand (proppant) & 2% or less chemical additives.
Slippage:	The phenomenon in multiphase flow when one phase flows faster than another phase, in other words slips past it. Because of this phenomenon, there is a difference between the holdups and cuts of the phases.
SO_2:	Sulfur dioxide.
SO_3	Sulfur trioxide.
Sonic Log:	See "Dipole Sonic Log".
Spacing Unit:	A surface area allotted to a well by regulations or field rules issued by a governmental authority having jurisdiction for the drilling and production of a well.
Spacing:	Distance separating wells in a field to optimize recovery of oil and gas.
SPDES:	State Pollutant Discharge Elimination System.
Spring:	A place where groundwater naturally flows from underground onto land or into a body of surface water.
Spudding:	The breaking of the earth's surface in the initial stage of drilling a well.
Squeeze:	Technique where cement is forced under pressure into the annular space between casing and the wellbore, between two strings of pipe, or into the casing-hole annulus.
SRBC:	Susquehanna River Basin Commission.
Stage:	Isolation of a specific interval of the wellbore and the associated interval of the formation for the purpose of maintaining sufficient fracturing pressure.
Stage Plug:	A device used to mechanically isolate a specific interval of the wellbore and the formation for the purpose of maintaining sufficient fracturing pressure.
Standpipe:	A vertical pipe rising along the side of the derrick or mast. It joins the discharge line leading from the mud pump to the rotary hose and through which mud is pumped going into the hole.
Stimulation:	The act of increasing a well's productivity by artificial means such as hydraulic fracturing, acidizing, and shooting.

Term	Definition
Stratigraphic Test Well:	A hole drilled to gather engineering, geologic or hydrological information including but not limited to lithology, structural, porosity, permeability and geophysical data.
Stratigraphy:	The study of rock layering, including the history, composition, relative ages and distribution of different rock units.
Stratum (plural strata):	Sedimentary rock layer, typically referred to as a formation, member, or bed.
Stream's Designated Best Use:	Each waterbody in NYS has been assigned a classification, which reflects the designated "best uses" of the waterbody. These best uses typically include the ability to support fish and aquatic wildlife, recreational uses (fishing, boating) and, for some waters, public bathing, drinking water use or shellfishing. Water quality is considered to be good if the waters support their best uses.
Substructure:	The foundation on which the derrick and drawworks sit. It contains space for storage and well-control equipment.
Surface Casing:	Casing extending from the surface through the potable fresh water zone.
Surface Impoundment:	A liquid containment facility that can be installed in a natural topographical depression, excavation, or bermed area formed primarily of earthen materials, then lined with a geomembrane or a combination of other geosynthetic materials.
Surfactants:	Chemical additives that reduce surface tension; or a surface active substance. Detergent is a surfactant.
SWPPP:	Stormwater Pollution Prevention Plan.
SWTR:	Surface Water Treatment Rule.
Target Formation:	The reservoir that the driller is trying to reach when drilling the well.
TCEQ:	Texas Commission on Environmental Quality.
Tcf:	Trillion cubic feet.
TD:	Total depth.
TDS:	Total Dissolved Solids. The dry weight of dissolved material, organic and inorganic, contained in water and usually expressed in mg/L or ppm.
TEG:	Triethylene Glycol.
Tensile Strength:	The force per unit cross-sectional area required to pull a substance apart.
Tight Formation:	Formation with very low permeability.
TMD:	Total measured depth.
TNC:	Transient non-community (in the context of water systems) or The Nature Conservancy.
TOC:	Total Organic Carbon.
Total Kjeldahl Nitrogen:	The sum of organic nitrogen; ammonium NH_3 and ammonia NH_4+ in water and soil analyses.
Tote:	A container used in the storage of various solid powder or liquid bulk products.
Trap:	Any geological barrier which restricts the migration of oil & gas.
TVD:	True vertical depth.
Turbidity:	Amount of suspended solids in a liquid.

Term	Definition
UA:	Urbanized areas.
UC:	Urban clusters.
UIC – Underground Injection Control:	A program administered by the Environmental Protection Agency, primacy state, or Indian tribe under the Safe Drinking Water Act to ensure that subsurface emplacement of fluids does not endanger underground sources of drinking water.
ULSF:	Ultra-Low Sulfur (Diesel) Fuel.
UN:	United Nations.
Unfiltered Surface Water Supplies:	Those that the U.S. EPA and NYSDOH have determined meet the requirements of the "Interim Enhanced Surface Water Treatment Rule" (IESWT Rule) for unfiltered water supply systems. The IESWT Rule is a December 16, 1998 amendment to the Surface Water Treatment Rule that was originally promulgated by EPA on June 29, 1989. In New York State, this includes the NYC Drinking Water Supply Watershed and the Skaneateles Drinking Water Supply Watershed.
UOC:	Unspecified Organic Contaminant.
USCG:	United States Coast Guard.
USDOT:	United States Department of Transportation.
USDW - Underground Source of Drinking Water:	An aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/L total dissolved solids and is not an exempted aquifer.
Water Well:	Any residential well used to supply potable water.
USEPA:	United States Environmental Protection Agency.
USGS:	United States Geological Survey.
Viscosity:	A measure of the degree to which a fluid resists flow under an applied force.
Vitrinite Reflectance:	A measurement of the maturity of organic matter with respect to whether it has generated hydrocarbons or could be an effective source rock.
VMT:	Vehicle Miles per Trip.
VOC:	Volatile Organic Compound.
Watershed:	The region drained by, or contributing water to, a stream, lake, or other body of water.
Well Location Plat:	A map of parcels of land with the proposed well and other features, particularly adjoining parcel boundaries.
Well Pad:	The area directly disturbed during drilling and operation of a gas well.
Wellbore:	A borehole; the hole drilled by the bit. A wellbore may have casing in it or it may be open (uncased); or part of it may be cased, and part of it may be open.
Wellhead:	The equipment installed at the surface of the wellbore. A wellhead includes such equipment as the casinghead and tubing head.
Well site:	Includes the well pad and access roads, equipment storage and staging areas, vehicle turnarounds, and any other areas directly or indirectly impacted by activities involving a well.
Wetland:	Any area regulated pursuant to Part 663.
Wildcat:	Well drilled to discover a previously unknown oil or gas pool or a well drilled one mile or more from a producing

Term	Definition
	well.
Wireline:	A general term used to describe well-intervention operations conducted using single-strand or multistrand wire or cable for intervention in oil or gas wells. Although applied inconsistently, the term commonly is used in association with electric logging and cables incorporating electrical conductors.
WMA:	Wildlife Management Area.
WOC Time:	"Waiting on cement" time. Pertaining to the time when drilling or completion operations are suspended so that the cement in a well can harden sufficiently.
Workover:	Repair operations on a producing well to restore or increase production.
ZLD:	Zero liquid discharge.
Zonal Isolation:	The state of keeping fluids in one zone separate from the fluids in another zone. In the case of a well, isolation is maintained by appropriate use of casing, cement, plugs and packers.
Zone:	A rock stratum of different character or fluid content from other strata.

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Appendices

REVISED DRAFT
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

New York State Department of Environmental Conservation

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[1] Updated/revised July 2011
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Appendix 1

FEMA
Flood Insurance Rate Map
Availability

Excerpted from Alpha Environmental, 2009
Updated by NYSDEC

Updated July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ALBANY COUNTY	ALBANY, CITY OF	04/15/1980
ALBANY COUNTY	ALTAMONT, VILLAGE OF	08/15/1983
ALBANY COUNTY	BERNE,TOWN OF	08/01/1987 (L)
ALBANY COUNTY	BETHLEHEM, TOWN OF	04/17/1984
ALBANY COUNTY	COEYMANS, TOWN OF	08/03/1989
ALBANY COUNTY	COHOES, CITY OF	12/4/1979
ALBANY COUNTY	COLONIE, TOWN OF	09/05/1979
ALBANY COUNTY	GREEN ISLAND, VILLAGE OF	06/04/1980
ALBANY COUNTY	GUILDERLAND, TOWN OF	01/06/1983
ALBANY COUNTY	KNOX, TOWNSHIP OF	08/13/1982 (M)
ALBANY COUNTY	MENANDS, VILLAGE OF	03/18/1980
ALBANY COUNTY	NEW SCOTLAND, TOWN OF	12/1/1982
ALBANY COUNTY	RAVENA, VILLAGE OF	04/02/1982 (M)
ALBANY COUNTY	RENSSELAERVILLE, TOWN OF	08/27/1982 (M)
ALBANY COUNTY	VOORHEESVILLE, VILLAGE OF	12/1/1982
ALBANY COUNTY	WATERVLIET, CITY OF	01/02/1980
ALBANY COUNTY	WESTERLO, TOWN OF	08/03/1989
ALLEGANY COUNTY	ALFRED, TOWN OF	10/07/1983 (M)
ALLEGANY COUNTY	ALFRED, VILLAGE OF	02/15/1980
ALLEGANY COUNTY	ALLEN, TOWN OF	07/16/1982 (M)
ALLEGANY COUNTY	ALMA, TOWN OF	10/07/1983 (M)
ALLEGANY COUNTY	ALMOND, VILLAGE OF	02/15/1980
ALLEGANY COUNTY	AMITY, TOWN OF	12/18/1984
ALLEGANY COUNTY	ANDOVER, TOWN OF	03/02/1998
ALLEGANY COUNTY	ANDOVER, VILLAGE OF	04/02/1979
ALLEGANY COUNTY	ANGELICA, TOWN OF	12/31/1982 (M)
ALLEGANY COUNTY	ANGELICA, VILLAGE OF	02/01/1984
ALLEGANY COUNTY	BELFAST, TOWN OF	08/06/1982 (M)
ALLEGANY COUNTY	BELMONT, VILLAGE OF	12/18/1984
ALLEGANY COUNTY	BIRDSALL, TOWN OF	07/16/1982 (M)
ALLEGANY COUNTY	BOLIVAR, TOWN OF	07/30/1982 (M)
ALLEGANY COUNTY	BOLIVAR, VILLAGE OF	01/19/1996
ALLEGANY COUNTY	BURNS, TOWN OF	07/16/1982 (M)
ALLEGANY COUNTY	CANASERAGA, VILLAGE OF	12/02/1983 (M)
ALLEGANY COUNTY	CANEADEA, TOWN OF	08/20/1982 (M)
ALLEGANY COUNTY	CLARKSVILLE, TOWN OF	11/12/1982 (M)
ALLEGANY COUNTY	CUBA, TOWN OF	07/30/1982 (M)
ALLEGANY COUNTY	CUBA, VILLAGE OF	04/17/1978
ALLEGANY COUNTY	FRIENDSHIP, TOWN OF	12/18/1984
ALLEGANY COUNTY	GENESEE, TOWN OF	07/30/1982 (M)
ALLEGANY COUNTY	GRANGER, TOWN OF	10/07/1983 (M)
ALLEGANY COUNTY	GROVE, TOWN OF	11/6/1991

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ALLEGANY COUNTY	HUME, TOWN OF	10/2/1997
ALLEGANY COUNTY	INDEPENDENCE, TOWN OF	07/09/1982 (M)
ALLEGANY COUNTY	NEW HUDSON, TOWN OF	08/20/1982 (M)
ALLEGANY COUNTY	RICHBURG, VILLAGE OF	01/05/1978
ALLEGANY COUNTY	RUSHFORD, TOWN OF	12/23/1983 (M)
ALLEGANY COUNTY	SCIO, TOWN OF	03/18/1985
ALLEGANY COUNTY	WARD,TOWN OF	(NSFHA)
ALLEGANY COUNTY	WELLSVILLE, TOWN OF	03/18/1985
ALLEGANY COUNTY	WELLSVILLE, VILLAGE OF	07/17/1978
ALLEGANY COUNTY	WEST ALMOND, TOWN OF	(NSFHA)
ALLEGANY COUNTY	WILLING, TOWN OF	12/24/1982 (M)
ALLEGANY COUNTY	WIRT, TOWN OF	06/25/1982 (M)
BROOME COUNTY	BARKER, TOWN OF	02/05/1992
BROOME COUNTY	BINGHAMTON, CITY OF	06/01/1977
BROOME COUNTY	BINGHAMTON, TOWN OF	01/06/1984 (M)
BROOME COUNTY	CHENANGO, TOWN OF	08/17/1981
BROOME COUNTY	COLESVILLE, TOWN OF	01/20/1993
BROOME COUNTY	CONKLIN, TOWN OF	07/17/1981
BROOME COUNTY	DICKINSON, TOWN OF	04/15/1977
BROOME COUNTY	ENDICOTT, VILLAGE OF	09/07/1998
BROOME COUNTY	FENTON, TOWN OF	08/03/1981
BROOME COUNTY	JOHNSON CITY, VILLAGE OF	09/30/1977
BROOME COUNTY	KIRKWOOD, TOWN OF	06/01/1977
BROOME COUNTY	LISLE, TOWN OF	08/20/2002
BROOME COUNTY	LISLE, VILLAGE OF	01/06/1984 (M)
BROOME COUNTY	MAINE, TOWN OF	02/05/1992
BROOME COUNTY	NANTICOKE, TOWN OF	12/18/1985
BROOME COUNTY	PORT DICKINSON, VILLAGE OF	05/02/1977
BROOME COUNTY	SANFORD, TOWN OF	06/04/1980
BROOME COUNTY	TRIANGLE, TOWN OF	07/20/1984 (M)
BROOME COUNTY	UNION, TOWN OF	09/30/1988
BROOME COUNTY	VESTAL, TOWN OF	03/02/1998
BROOME COUNTY	WHITNEY POINT, VILLAGE OF	01/06/1984 (M)
BROOME COUNTY	WINDSOR, TOWN OF	09/30/1992
BROOME COUNTY	WINDSOR, VILLAGE OF	05/18/1992
CATTARAUGUS COUNTY	ALLEGANY, TOWN OF	11/15/1978
CATTARAUGUS COUNTY	ALLEGANY, VILLAGE OF	12/17/1991
CATTARAUGUS COUNTY	ASHFORD, TOWNSHIP OF	05/25/1984
CATTARAUGUS COUNTY	CARROLLTON, TOWN OF	03/18/1983 (M)
CATTARAUGUS COUNTY	CATTARAUGUS, VILLAGE OF	04/20/1984 (M)
CATTARAUGUS COUNTY	COLD SPRING, TOWN OF	03/01/1978
CATTARAUGUS COUNTY	CONEWANGO, TOWN OF	07/30/1982 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CATTARAUGUS COUNTY	DAYTON, TOWN OF	05/25/1984 (M)
CATTARAUGUS COUNTY	DELEVAN, VILLAGE OF	01/20/1984 (M)
CATTARAUGUS COUNTY	EAST OTTO, TOWN OF	04/20/1984 (M)
CATTARAUGUS COUNTY	EAST RANDOLPH, VILLAGE OF	02/01/1978
CATTARAUGUS COUNTY	ELLICOTTVILLE, TOWN OF	01/19/2000
CATTARAUGUS COUNTY	ELLICOTTVILLE, VILLAGE OF	05/02/1994
CATTARAUGUS COUNTY	FARMERSVILLE, TOWN OF	07/23/1982 (M)
CATTARAUGUS COUNTY	FRANKLINVILLE, TOWN OF	07/17/1978
CATTARAUGUS COUNTY	FRANKLINVILLE, VILLAGE OF	07/03/1978
CATTARAUGUS COUNTY	FREEDOM, TOWN OF	08/19/1991
CATTARAUGUS COUNTY	GREAT VALLEY, TOWN OF	07/17/1978
CATTARAUGUS COUNTY	HINSDALE, TOWN OF	01/17/1979
CATTARAUGUS COUNTY	HUMPHREY, TOWN OF	08/13/1982 (M)
CATTARAUGUS COUNTY	ISCHUA, TOWN OF	08/15/1978
CATTARAUGUS COUNTY	LEON, TOWN OF	08/13/1982 (M)
CATTARAUGUS COUNTY	LIMESTONE, VILLAGE OF	04/17/1978
CATTARAUGUS COUNTY	LITTLE VALLEY, TOWN OF	06/22/1984 (M)
CATTARAUGUS COUNTY	LITTLE VALLEY, VILLAGE OF	02/01/1978
CATTARAUGUS COUNTY	LYNDON, TOWN OF	07/16/1982 (M)
CATTARAUGUS COUNTY	MACHIAS, TOWN OF	08/20/1982 (M)
CATTARAUGUS COUNTY	MANSFIELD, TOWN OF	05/25/1984 (M)
CATTARAUGUS COUNTY	NAPOLI, TOWN OF	07/02/1982 (M)
CATTARAUGUS COUNTY	NEW ALBION, TOWN OF	12/03/1982 (M)
CATTARAUGUS COUNTY	OLEAN, CITY OF	05/09/1980
CATTARAUGUS COUNTY	OLEAN, TOWN OF	02/01/1979
CATTARAUGUS COUNTY	OTTO, TOWN OF	04/20/1984 (M)
CATTARAUGUS COUNTY	PERRYSBURG, TOWN OF	04/20/1984 (M)
CATTARAUGUS COUNTY	PERSIA, TOWN OF	04/20/1984 (M)
CATTARAUGUS COUNTY	PORTVILLE, TOWN OF	07/18/1983
CATTARAUGUS COUNTY	PORTVILLE, VILLAGE OF	04/17/1978
CATTARAUGUS COUNTY	RANDOLPH, TOWN OF	11/05/1982 (M)
CATTARAUGUS COUNTY	RANDOLPH, VILLAGE OF	08/01/1978
CATTARAUGUS COUNTY	SALAMANCA, CITY OF	04/17/1978
CATTARAUGUS COUNTY	SALAMANCA, TOWN OF	11/1/1979
CATTARAUGUS COUNTY	SOUTH DAYTON, VILLAGE OF	01/05/1978
CATTARAUGUS COUNTY	SOUTH VALLEY, TOWN OF	12/02/1983 (M)
CATTARAUGUS COUNTY	YORKSHIRE, TOWN OF	05/25/1984 (M)
CATTARAUGUS COUNTY/ERIE COUNTY/CHAUTAUQUA COUNTY/ALLEGANY COUNTY	SENECA NATION OF INDIANS	09/30/1988
CAYUGA COUNTY	AUBURN, CITY OF	08/02/2007
CAYUGA COUNTY	AURELIUS, TOWN OF	08/02/2007

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CAYUGA COUNTY	AURORA, VILLAGE OF	08/02/2007
CAYUGA COUNTY	BRUTUS, TOWN OF	08/02/2007
CAYUGA COUNTY	CATO, TOWN OF	08/02/2007
CAYUGA COUNTY	CATO, VILLAGE OF	08/02/2007
CAYUGA COUNTY	CAYUGA, VILLAGE OF	08/02/2007
CAYUGA COUNTY	CONQUEST, TOWN OF	08/02/2007
CAYUGA COUNTY	FAIR HAVEN, VILLAGE OF	08/02/2007
CAYUGA COUNTY	FLEMING, TOWN OF	08/02/2007
CAYUGA COUNTY	GENOA,TOWN OF	08/02/2007
CAYUGA COUNTY	IRA, TOWN OF	08/02/2007
CAYUGA COUNTY	LEDYARD, TOWN OF	08/02/2007
CAYUGA COUNTY	LOCKE, TOWN OF	08/02/2007
CAYUGA COUNTY	MENTZ, TOWN OF	08/02/2007
CAYUGA COUNTY	MERIDIAN, VILLAGE OF	08/02/2007
CAYUGA COUNTY	MONTEZUMA, TOWN OF	08/02/2007
CAYUGA COUNTY	MORAVIA, TOWN OF	08/02/2007
CAYUGA COUNTY	MORAVIA, VILLAGE OF	08/02/2007
CAYUGA COUNTY	NILES, TOWN OF	08/02/2007
CAYUGA COUNTY	OWASCO, TOWN OF	08/02/2007
CAYUGA COUNTY	PORT BYRON, VILLAGE OF	08/02/2007
CAYUGA COUNTY	SCIPIO, TOWN OF	08/02/2007
CAYUGA COUNTY	SEMPRONIUS, TOWN OF	08/02/2007
CAYUGA COUNTY	SENNETT, TOWN OF	08/02/2007
CAYUGA COUNTY	SPRINGPORT, TOWN OF	08/02/2007
CAYUGA COUNTY	STERLING, TOWN OF	08/02/2007
CAYUGA COUNTY	SUMMER HILL, TOWN OF	08/02/2007
CAYUGA COUNTY	THROOP, TOWN OF	08/02/2007
CAYUGA COUNTY	UNION SPRINGS, VILLAGE OF	08/02/2007
CAYUGA COUNTY	VENICE, TOWN OF	08/02/2007
CAYUGA COUNTY	VICTORY, TOWN OF	08/02/2007
CAYUGA COUNTY	WEEDSPORT, VILLAGE OF	08/02/2007
CHAUTAUQUA COUNTY	ARKWRIGHT, TOWN OF	04/08/1983 (M)
CHAUTAUQUA COUNTY	BEMUS POINT, VILLAGE OF	11/2/1977
CHAUTAUQUA COUNTY	BROCTON, VILLAGE OF	(NSFHA)
CHAUTAUQUA COUNTY	BUSTI, TOWN OF	01/20/1993
CHAUTAUQUA COUNTY	CARROLL, TOWN OF	10/29/1982 (M)
CHAUTAUQUA COUNTY	CASSADAGA, VILLAGE OF	12/1/1977
CHAUTAUQUA COUNTY	CELORON, VILLAGE OF	03/18/1980
CHAUTAUQUA COUNTY	CHARLOTTE, TOWN OF	03/23/1984 (M)
CHAUTAUQUA COUNTY	CHAUTAUQUA, TOWN OF	06/15/1984
CHAUTAUQUA COUNTY	CHERRY CREEK, TOWN OF	07/02/1982 (M)
CHAUTAUQUA COUNTY	CHERRY CREEK, VILLAGE OF	02/15/1978

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CHAUTAUQUA COUNTY	CLYMER, TOWN OF	10/07/1983 (M)
CHAUTAUQUA COUNTY	DUNKIRK, CITY OF	02/04/1981
CHAUTAUQUA COUNTY	DUNKIRK, TOWN OF	08/06/1982 (M)
CHAUTAUQUA COUNTY	ELLERY, TOWN OF	03/18/1980
CHAUTAUQUA COUNTY	ELLICOTT, TOWN OF	08/01/1984
CHAUTAUQUA COUNTY	ELLINGTON, TOWN OF	10/07/1983(M)
CHAUTAUQUA COUNTY	FALCONER, VILLAGE OF	01/05/1978
CHAUTAUQUA COUNTY	FORESTVILLE, VILLAGE OF	03/18/1983(M)
CHAUTAUQUA COUNTY	FREDONIA, VILLAGE OF	11/15/1989
CHAUTAUQUA COUNTY	FRENCH CREEK, TOWN OF	06/08/1984 (M)
CHAUTAUQUA COUNTY	GERRY, TOWN OF	01/06/1984 (M)
CHAUTAUQUA COUNTY	HANOVER, TOWN OF	12/18/1984
CHAUTAUQUA COUNTY	HARMONY, TOWNSHIP OF	12/01/1986 (L)
CHAUTAUQUA COUNTY	JAMESTOWN, CITY OF	06/01/1978
CHAUTAUQUA COUNTY	KIANTONE, TOWN OF	02/02/1996
CHAUTAUQUA COUNTY	LAKEWOOD, VILLAGE OF	11/2/1977
CHAUTAUQUA COUNTY	MAYVILLE, VILLAGE OF	01/05/1978
CHAUTAUQUA COUNTY	MINA, TOWN OF	01/02/2003
CHAUTAUQUA COUNTY	NORTH HARMONY, TOWN OF	02/15/1980
CHAUTAUQUA COUNTY	PANAMA, VILLAGE OF	03/01/1978
CHAUTAUQUA COUNTY	POLAND, TOWN OF	03/11/1983 (M)
CHAUTAUQUA COUNTY	POMFRET, TOWN OF	12/18/1984
CHAUTAUQUA COUNTY	PORTLAND, TOWN OF	10/07/1983 (M)
CHAUTAUQUA COUNTY	RIPLEY,TOWN OF	(NSFHA)
CHAUTAUQUA COUNTY	SHERIDAN, TOWN OF	10/07/1983 (M)
CHAUTAUQUA COUNTY	SHERMAN, VILLAGE OF	03/01/1978
CHAUTAUQUA COUNTY	SHERMAN,TOWN OF	01/06/1984 (M)
CHAUTAUQUA COUNTY	SILVER CREEK, VILLAGE OF	08/01/1983
CHAUTAUQUA COUNTY	SINCLAIRVILLE, VILLAGE OF	12/1/1977
CHAUTAUQUA COUNTY	STOCKTON, TOWN OF	10/21/1983 (M)
CHAUTAUQUA COUNTY	VILLENOVA, TOWN OF	05/21/1982 (M)
CHAUTAUQUA COUNTY	WESTFIELD, TOWN OF	06/08/1984 (M)
CHAUTAUQUA COUNTY	WESTFIELD, VILLAGE OF	10/07/1983 (M)
CHEMUNG COUNTY	ASHLAND, TOWN OF	01/16/1980
CHEMUNG COUNTY	BALDWIN, TOWN OF	07/23/1982 (M)
CHEMUNG COUNTY	BIG FLATS, TOWN OF	08/18/1992
CHEMUNG COUNTY	CATLIN, TOWN OF	06/22/1984 (M)
CHEMUNG COUNTY	CHEMUNG, TOWN OF	09/03/1980
CHEMUNG COUNTY	ELMIRA HEIGHTS, VILLAGE OF	09/29/1996
CHEMUNG COUNTY	ELMIRA, CITY OF	04/02/1997
CHEMUNG COUNTY	ELMIRA, TOWN OF	09/29/1996
CHEMUNG COUNTY	ERIN, TOWN OF	08/13/1982 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CHEMUNG COUNTY	HORSEHEADS, TOWN OF	09/29/1996
CHEMUNG COUNTY	HORSEHEADS, VILLAGE OF	09/29/1996
CHEMUNG COUNTY	MILLPORT, VILLAGE OF	06/15/1988 (M)
CHEMUNG COUNTY	SOUTHPORT, TOWN OF	08/05/1991
CHEMUNG COUNTY	VAN ETTEN, TOWN OF	09/28/1979 (M)
CHEMUNG COUNTY	VAN ETTEN, VILLAGE OF	07/01/1988 (L)
CHEMUNG COUNTY	VETERAN, TOWN OF	02/18/1983 (M)
CHEMUNG COUNTY	WELLSBURG, VILLAGE OF	06/15/1981
CHENANGO COUNTY	AFTON, TOWN OF	11/26/2010
CHENANGO COUNTY	AFTON, VILLAGE OF	11/26/2010
CHENANGO COUNTY	BAINBRIDGE, TOWN OF	11/26/2010
CHENANGO COUNTY	BAINBRIDGE, VILLAGE OF	11/26/2010
CHENANGO COUNTY	COLUMBUS, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	COVENTRY, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	EARLVILLE, VILLAGE OF	11/26/2010 (M)
CHENANGO COUNTY	GERMAN, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	GREENE, TOWN OF	11/26/2010
CHENANGO COUNTY	GREENE, VILLAGE OF	11/26/2010
CHENANGO COUNTY	GUILFORD, TOWN OF	11/26/2010
CHENANGO COUNTY	LINCKLAEN, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	MC DONOUGH, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	NEW BERLIN, TOWN OF	11/26/2010
CHENANGO COUNTY	NEW BERLIN, VILLAGE OF	11/26/2010
CHENANGO COUNTY	NORTH NORWICH, TOWN OF	11/26/2010
CHENANGO COUNTY	NORWICH, CITY OF	11/26/2010
CHENANGO COUNTY	NORWICH, TOWN OF	11/26/2010
CHENANGO COUNTY	OTSELIC, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	OXFORD, TOWN OF	11/26/2010
CHENANGO COUNTY	OXFORD, VILLAGE OF	11/26/2010
CHENANGO COUNTY	PHARSALIA, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	PITCHER, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	PLYMOUTH, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	PRESTON, TOWN OF	11/26/2010
CHENANGO COUNTY	SHERBURNE, TOWN OF	11/26/2010
CHENANGO COUNTY	SHERBURNE, VILLAGE OF	11/26/2010
CHENANGO COUNTY	SMITHVILLE, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	SMYRNA, TOWN OF	11/26/2010
CHENANGO COUNTY	SMYRNA, VILLAGE OF	11/26/2010 (M)
CLINTON COUNTY	ALTONA, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	AUSABLE, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	BEEKMANTOWN, TOWN OF	09/28/2007
CLINTON COUNTY	BLACK BROOK, TOWN OF	09/28/2007

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CLINTON COUNTY	CHAMPLAIN, TOWN OF	09/28/2007
CLINTON COUNTY	CHAMPLAIN, VILLAGE OF	09/28/2007
CLINTON COUNTY	CHAZY, TOWN OF	09/28/2007
CLINTON COUNTY	CLINTON, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	ELLENBURG, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	MOOERS, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	PERU,TOWN OF	09/28/2007
CLINTON COUNTY	PLATTSBURGH, CITY OF	09/28/2007
CLINTON COUNTY	PLATTSBURGH, TOWN OF	09/28/2007
CLINTON COUNTY	ROUSES POINT, VILLAGE OF	09/28/2007
CLINTON COUNTY	SARANAC, TOWN OF	09/28/2007
CLINTON COUNTY	SCHUYLER FALLS, TOWN OF	09/28/2007
COLUMBIA COUNTY	ANCRAM, TOWN OF	06/05/1985 (M)
COLUMBIA COUNTY	AUSTERLITZ, TOWN OF	06/05/1985 (M)
COLUMBIA COUNTY	CANAAN, TOWN OF	07/03/1985 (M)
COLUMBIA COUNTY	CHATHAM, TOWN OF	09/15/1993
COLUMBIA COUNTY	CHATHAM, VILLAGE OF	12/15/1982
COLUMBIA COUNTY	CLAVERACK, TOWN OF	09/06/1989
COLUMBIA COUNTY	CLERMONT, TOWNSHIP OF	09/05/1984
COLUMBIA COUNTY	COPAKE, TOWN OF	06/19/1985 (M)
COLUMBIA COUNTY	GALLATIN, TOWN OF	10/16/1984
COLUMBIA COUNTY	GERMANTOWN, TOWN OF	05/11/1979 (M)
COLUMBIA COUNTY	GHENT, TOWN OF	01/01/1988 (L)
COLUMBIA COUNTY	GREENPORT, TOWN OF	11/15/1989
COLUMBIA COUNTY	HILLSDALE, TOWN OF	05/15/1985 (M)
COLUMBIA COUNTY	HUDSON, CITY OF	09/29/1989
COLUMBIA COUNTY	KINDERHOOK, TOWN OF	12/1/1982
COLUMBIA COUNTY	KINDERHOOK, VILLAGE OF	12/1/1982
COLUMBIA COUNTY	LIVINGSTON, TOWN OF	05/11/1979 (M)
COLUMBIA COUNTY	NEW LEBANON, TOWN OF	06/05/1985 (M)
COLUMBIA COUNTY	STOCKPORT, TOWN OF	01/19/1983
COLUMBIA COUNTY	STUYVESANT, TOWN OF	09/14/1979 (M)
COLUMBIA COUNTY	TAGHKANIC, TOWN OF	01/03/1986 (M)
COLUMBIA COUNTY	VALATIE, VILLAGE OF	12/1/1982
CORTLAND COUNTY	CINCINNATUS, TOWN OF	03/02/2010
CORTLAND COUNTY	CORTLAND, CITY OF	03/02/2010
CORTLAND COUNTY	CORTLANDVILLE, TOWN OF	03/02/2010
CORTLAND COUNTY	CUYLER, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	FREETOWN, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	HARFORD, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	HOMER, TOWN OF	03/02/2010
CORTLAND COUNTY	HOMER, VILLAGE OF	03/02/2010

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CORTLAND COUNTY	LAPEER, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	MARATHON, TOWN OF	03/02/2010
CORTLAND COUNTY	MARATHON, VILLAGE OF	03/02/2010
CORTLAND COUNTY	MCGRAW, VILLAGE OF	03/02/2010
CORTLAND COUNTY	PREBLE, TOWN OF	03/02/2010
CORTLAND COUNTY	SCOTT, TOWN OF	03/02/2010
CORTLAND COUNTY	SOLON, TOWN OF	03/02/2010
CORTLAND COUNTY	TAYLOR, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	TRUXTON, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	VIRGIL, TOWN OF	03/02/2010
CORTLAND COUNTY	WILLET, TOWN OF	03/02/2010 (M)
DELAWARE COUNTY	ANDES, TOWN OF	05/01/1985 (M)
DELAWARE COUNTY	ANDES, VILLAGE OF	04/01/1986 (L)
DELAWARE COUNTY	BOVINA, TOWN OF	05/01/1985 (M)
DELAWARE COUNTY	COLCHESTER,TOWN OF	02/04/1987
DELAWARE COUNTY	DAVENPORT, TOWN OF	02/02/2002
DELAWARE COUNTY	DELHI, TOWN OF	07/18/1985
DELAWARE COUNTY	DELHI, VILLAGE OF	07/18/1985
DELAWARE COUNTY	DEPOSIT, TOWN OF	03/18/1986 (M)
DELAWARE COUNTY	FLEISCHMANNS, VILLAGE OF	01/17/1986 (M)
DELAWARE COUNTY	FRANKLIN, TOWN OF	04/01/1988 (L)
DELAWARE COUNTY	FRANKLIN, VILLAGE OF	08/01/1987 (L)
DELAWARE COUNTY	HAMDEN,TOWN OF	03/04/1986 (M)
DELAWARE COUNTY	HANCOCK, TOWN OF	09/28/1990
DELAWARE COUNTY	HANCOCK, VILLAGE OF	09/28/1990
DELAWARE COUNTY	HARPERSFIELD, TOWN OF	06/05/1985 (M)
DELAWARE COUNTY	HOBART, VILLAGE OF	05/15/1985 (M)
DELAWARE COUNTY	KORTRIGHT, TOWN OF	05/15/1985 (M)
DELAWARE COUNTY	MARGARETVILLE, VILLAGE OF	06/04/1990
DELAWARE COUNTY	MASONVILLE, TOWN OF	11/01/1985 (M)
DELAWARE COUNTY	MEREDITH, TOWN OF	05/15/1985 (M)
DELAWARE COUNTY	MIDDLETOWN, TOWN OF	08/02/1993
DELAWARE COUNTY	ROXBURY, TOWN OF	05/15/1985 (M)
DELAWARE COUNTY	SIDNEY, TOWN OF	09/30/1987
DELAWARE COUNTY	SIDNEY, VILLAGE OF	09/30/1987
DELAWARE COUNTY	STAMFORD, TOWN OF	10/01/1986 (L)
DELAWARE COUNTY	STAMFORD, VILLAGE OF	08/01/1987 (L)
DELAWARE COUNTY	TOMPKINS, TOWN OF	11/15/1985 (M)
DELAWARE COUNTY	WALTON, TOWN OF	09/02/1988
DELAWARE COUNTY	WALTON, VILLAGE OF	04/02/1991
DELAWARE COUNTY/BROOME COUNTY	DEPOSIT, VILLAGE OF	02/01/1979

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
DUTCHESS COUNTY	AMENIA, TOWN OF	11/15/1989
DUTCHESS COUNTY	BEACON, CITY OF	03/01/1984
DUTCHESS COUNTY	BEEKMAN, TOWN OF	09/05/1984
DUTCHESS COUNTY	CLINTON, TOWN OF	07/05/1984
DUTCHESS COUNTY	DOVER, TOWN OF	07/04/1988
DUTCHESS COUNTY	EAST FISHKILL, TOWN OF	06/15/1984
DUTCHESS COUNTY	FISHKILL, TOWN OF	06/01/1984
DUTCHESS COUNTY	FISHKILL, VILLAGE OF	03/15/1984
DUTCHESS COUNTY	HYDE PARK, TOWN OF	06/15/1984
DUTCHESS COUNTY	LAGRANGE, TOWN OF	09/08/1999
DUTCHESS COUNTY	MILAN, TOWN OF	08/10/1979 (M)
DUTCHESS COUNTY	MILLBROOK, VILLAGE OF	02/27/1984 (M)
DUTCHESS COUNTY	MILLERTON, VILLAGE OF	01/03/1985
DUTCHESS COUNTY	NORTH EAST, TOWN OF	09/05/1984
DUTCHESS COUNTY	PAWLING, TOWN OF	01/03/1985
DUTCHESS COUNTY	PAWLING, VILLAGE OF	08/01/1984
DUTCHESS COUNTY	PINE PLAINS, TOWN OF	10/05/1984 (M)
DUTCHESS COUNTY	PLEASANT VALLEY, TOWN OF	01/16/1980
DUTCHESS COUNTY	POUGHKEEPSIE, CITY OF	01/05/1984
DUTCHESS COUNTY	POUGHKEEPSIE, TOWN OF	09/08/1999
DUTCHESS COUNTY	RED HOOK, TOWN OF	10/16/1984
DUTCHESS COUNTY	RED HOOK, VILLAGE OF	(NSFHA)
DUTCHESS COUNTY	RHINEBECK, TOWN OF	09/05/1984
DUTCHESS COUNTY	RHINEBECK, VILLAGE OF	02/01/1985
DUTCHESS COUNTY	STANFORD, TOWN OF	12/17/1991
DUTCHESS COUNTY	TIVOLI, VILLAGE OF	08/01/1984
DUTCHESS COUNTY	UNION VALE, TOWN OF	09/02/1988
DUTCHESS COUNTY	WAPPINGER, TOWN OF	09/22/1999
DUTCHESS COUNTY	WAPPINGERS FALLS, VILLAGE OF	09/22/1999
DUTCHESS COUNTY	WASHINGTON, TOWN OF	08/17/1979 (M)
ERIE COUNTY	AKRON, VILLAGE OF	11/19/1980
ERIE COUNTY	ALDEN, TOWN OF	02/06/1991
ERIE COUNTY	ALDEN, VILLAGE OF	01/06/1984 (M)
ERIE COUNTY	AMHERST, TOWN OF	10/16/1992
ERIE COUNTY	ANGOLA, VILLAGE OF	08/06/2002
ERIE COUNTY	AURORA, TOWN OF	04/16/1979
ERIE COUNTY	BLASDELL, VILLAGE OF	06/25/1976 (M)
ERIE COUNTY	BOSTON, TOWN OF	09/30/1981
ERIE COUNTY	BRANT, TOWN OF	01/06/1984 (M)
ERIE COUNTY	BUFFALO, CITY OF	09/26/2008
ERIE COUNTY	CHEEKTOWAGA, TOWN OF	03/15/1984
ERIE COUNTY	CLARENCE, TOWN OF	03/05/1996

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ERIE COUNTY	COLDEN, TOWN OF	07/02/1979
ERIE COUNTY	COLLINS,TOWN OF	09/26/2008
ERIE COUNTY	CONCORD, TOWN OF	09/04/1986
ERIE COUNTY	DEPEW, VILLAGE OF	08/03/1981
ERIE COUNTY	EAST AURORA, VILLAGE OF	08/06/2002
ERIE COUNTY	EDEN, TOWN OF	08/24/1979 (M)
ERIE COUNTY	ELMA,TOWN OF	06/22/1998
ERIE COUNTY	EVANS, TOWN OF	02/02/2002
ERIE COUNTY	FARNHAM, VILLAGE OF	(NSFHA)
ERIE COUNTY	GRAND ISLAND, TOWN OF	09/26/2008
ERIE COUNTY	HAMBURG, TOWN OF	12/20/2001
ERIE COUNTY	HAMBURG, VILLAGE OF	01/20/1982
ERIE COUNTY	HOLLAND, TOWN OF	09/26/2008
ERIE COUNTY	KENMORE,VILLAGE OF	(NSFHA)
ERIE COUNTY	LACKAWANNA, CITY OF	07/02/1980
ERIE COUNTY	LANCASTER, TOWN OF	02/23/2001
ERIE COUNTY	LANCASTER, VILLAGE OF	07/02/1979
ERIE COUNTY	MARILLA, TOWN OF	09/29/1978
ERIE COUNTY	NEWSTEAD, TOWN OF	05/04/1992
ERIE COUNTY	ORCHARD PARK, TOWN OF	03/16/1983
ERIE COUNTY	ORCHARD PARK, VILLAGE OF	(NSFHA)
ERIE COUNTY	SARDINIA, TOWN OF	01/16/2003
ERIE COUNTY	SLOAN, VILLAGE OF	(NSFHA)
ERIE COUNTY	SPRINGVILLE, VILLAGE OF	07/17/1986
ERIE COUNTY	TONAWANDA, CITY OF	09/26/2008
ERIE COUNTY	TONAWANDA, TOWN OF	11/12/1982
ERIE COUNTY	WALES, TOWN OF	09/26/2008
ERIE COUNTY	WEST SENECA, TOWN OF	09/30/1992
ERIE COUNTY	WILLIAMSVILLE, VILLAGE OF	09/26/2008
ERIE COUNTY/CATTARAUGUS COUNTY	GOWANDA, VILLAGE OF	09/26/2008
ESSEX COUNTY	CHESTERFIELD, TOWN OF	05/04/1987
ESSEX COUNTY	CROWN POINT,TOWN OF	07/16/1987
ESSEX COUNTY	ELIZABETHTOWN, TOWN OF	01/20/1993
ESSEX COUNTY	ESSEX, TOWN OF	04/03/1987
ESSEX COUNTY	JAY, TOWN OF	06/17/2002
ESSEX COUNTY	KEENE, TOWN OF	06/05/1985 (M)
ESSEX COUNTY	KEESEVILLE, VILLAGE OF	09/28/2007 (M)
ESSEX COUNTY	LAKE PLACID, VILLAGE OF	(NSFHA)
ESSEX COUNTY	LEWIS, TOWN OF	05/15/1985 (M)
ESSEX COUNTY	MINERVA, TOWN OF	10/05/1984 (M)
ESSEX COUNTY	MORIAH, TOWN OF	09/24/1984 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ESSEX COUNTY	NEWCOMB, TOWN OF	06/05/1985 (M)
ESSEX COUNTY	NORTH ELBA, TOWN OF	08/23/2001
ESSEX COUNTY	NORTH HUDSON, TOWN OF	05/15/1985 (M)
ESSEX COUNTY	PORT HENRY, VILLAGE OF	07/16/1987
ESSEX COUNTY	SCHROON, TOWN OF	11/16/1995
ESSEX COUNTY	ST. ARMAND, TOWN OF	02/05/1986
ESSEX COUNTY	TICONDEROGA, TOWN OF	09/06/1996
ESSEX COUNTY	WESTPORT, TOWN OF	09/04/1987
ESSEX COUNTY	WILLSBORO, TOWN OF	05/18/1992
ESSEX COUNTY	WILMINGTON, TOWN OF	11/16/1995
FRANKLIN COUNTY	BANGOR, TOWN OF	(NSFHA)
FRANKLIN COUNTY	BELLMONT, TOWN OF	08/05/1985 (M)
FRANKLIN COUNTY	BOMBAY, TOWN OF	02/15/1985 (M)
FRANKLIN COUNTY	BRANDON, TOWN OF	(NSFHA)
FRANKLIN COUNTY	BRIGHTON, TOWN OF	(NSFHA)
FRANKLIN COUNTY	BRUSHTON, VILLAGE OF	02/19/1986 (M)
FRANKLIN COUNTY	BURKE, TOWN OF	02/19/1986 (M)
FRANKLIN COUNTY	BURKE, VILLAGE OF	(NSFHA)
FRANKLIN COUNTY	CHATEAUGAY, VILLAGE OF	(NSFHA)
FRANKLIN COUNTY	CONSTABLE, TOWN OF	(NSFHA)
FRANKLIN COUNTY	DICKINSON, TOWN OF	03/18/1986 (M)
FRANKLIN COUNTY	DUANE, TOWN OF	(NSFHA)
FRANKLIN COUNTY	FORT COVINGTON, TOWN OF	12/23/1983 (M)
FRANKLIN COUNTY	FRANKLIN, TOWN OF	09/24/1984 (M)
FRANKLIN COUNTY	HARRIETSTOWN, TOWN OF	01/03/1985
FRANKLIN COUNTY	MALONE, TOWN OF	09/04/1985 (M)
FRANKLIN COUNTY	MALONE, VILLAGE OF	04/03/1978
FRANKLIN COUNTY	MOIRA, TOWN OF	04/15/1986 (M)
FRANKLIN COUNTY	SANTA CLARA, TOWN OF	(NSFHA)
FRANKLIN COUNTY	SARANAC LAKE, VILLAGE OF	01/02/1992
FRANKLIN COUNTY	TUPPER LAKE, TOWN OF	(NSFHA)
FRANKLIN COUNTY	TUPPER LAKE,VILLAGE OF	03/01/1987 (L)
FRANKLIN COUNTY	WAVERLY, TOWN OF	(NSFHA)
FRANKLIN COUNTY	WESTVILLE, TOWN OF	02/15/1985 (M)
FULTON COUNTY	BLEECKER,TOWN OF	07/18/1985 (M)
FULTON COUNTY	BROADALBIN, TOWN OF	01/03/1985 (M)
FULTON COUNTY	BROADALBIN, VILLAGE OF	04/15/1986 (M)
FULTON COUNTY	CAROGA, TOWN OF	07/18/1985 (M)
FULTON COUNTY	EPHRATAH, TOWN OF	07/03/1985 (M)
FULTON COUNTY	GLOVERSVILLE, CITY OF	09/30/1983
FULTON COUNTY	JOHNSTOWN, CITY OF	07/18/1983
FULTON COUNTY	JOHNSTOWN, TOWN OF	07/03/1985 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
FULTON COUNTY	MAYFIELD, TOWN OF	08/05/1985 (M)
FULTON COUNTY	NORTHAMPTON, TOWN OF	08/19/1985 (M)
FULTON COUNTY	NORTHVILLE, VILLAGE OF	(NSFHA)
FULTON COUNTY	OPPENHEIM, TOWN OF	06/18/1976
FULTON COUNTY	PERTH, TOWN OF	02/15/1985 (M)
FULTON COUNTY	STRATFORD, TOWN OF	01/03/1985 (M)
GENESEE COUNTY	ALABAMA, TOWN OF	11/18/1983 (M)
GENESEE COUNTY	ALEXANDER, VILLAGE OF	05/04/1987
GENESEE COUNTY	ALEXANDER,TOWN OF	05/04/1987
GENESEE COUNTY	BATAVIA, CITY OF	09/16/1982
GENESEE COUNTY	BATAVIA, TOWN OF	01/17/1985
GENESEE COUNTY	BERGEN, TOWN OF	07/06/1984 (M)
GENESEE COUNTY	BERGEN, VILLAGE OF	06/08/1979 (M)
GENESEE COUNTY	BETHANY, TOWN OF	09/24/1984 (M)
GENESEE COUNTY	BYRON, TOWN OF	02/01/1988 (L)
GENESEE COUNTY	CORFU, VILLAGE OF	10/15/1985 (M)
GENESEE COUNTY	DARIEN, TOWN OF	07/06/1984 (M)
GENESEE COUNTY	ELBA, TOWN OF	10/05/1984 (M)
GENESEE COUNTY	ELBA, VILLAGE OF	01/20/1984 (M)
GENESEE COUNTY	LE ROY, TOWN OF	09/14/1979 (M)
GENESEE COUNTY	LE ROY, VILLAGE OF	08/03/1981
GENESEE COUNTY	OAKFIELD, TOWN OF	05/25/1984 (M)
GENESEE COUNTY	OAKFIELD, VILLAGE OF	03/23/1984 (M)
GENESEE COUNTY	PAVILION, TOWN OF	02/27/1984 (M)
GENESEE COUNTY	PEMBROKE, TOWN OF	01/20/1984 (M)
GENESEE COUNTY	STAFFORD,TOWN OF	07/16/1982
GENESEE COUNTY/WYOMING COUNTY	ATTICA, VILLAGE OF	07/03/1986
GREENE COUNTY	ASHLAND, TOWN OF	05/16/2008
GREENE COUNTY	ATHENS, TOWN OF	05/16/2008
GREENE COUNTY	ATHENS, VILLAGE OF	05/16/2008
GREENE COUNTY	CAIRO, TOWN OF	05/16/2008
GREENE COUNTY	CATSKILL, TOWN OF	05/16/2008
GREENE COUNTY	CATSKILL, VILLAGE OF	05/16/2008
GREENE COUNTY	COXSACKIE, TOWN OF	05/16/2008
GREENE COUNTY	COXSACKIE, VILLAGE OF	05/16/2008
GREENE COUNTY	DURHAM, TOWN OF	05/16/2008 (M)
GREENE COUNTY	GREENVILLE, TOWN OF	05/16/2008 (M)
GREENE COUNTY	HALCOTT, TOWN OF	05/16/2008 (M)
GREENE COUNTY	HUNTER, TOWN OF	05/16/2008
GREENE COUNTY	HUNTER, VILLAGE OF	05/16/2008
GREENE COUNTY	JEWETT, TOWN OF	05/16/2008

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
GREENE COUNTY	LEXINGTON, TOWN OF	05/16/2008
GREENE COUNTY	NEW BALTIMORE, TOWN OF	05/16/2008 (M)
GREENE COUNTY	PRATTSVILLE, TOWN OF	05/16/2008
GREENE COUNTY	TANNERSVILLE, VILLAGE OF	05/16/2008
GREENE COUNTY	WINDHAM, TOWN OF	05/16/2008
HAMILTON COUNTY	ARIETTA, TOWN OF	(NSFHA)
HAMILTON COUNTY	BENSON, TOWN OF	(NSFHA)
HAMILTON COUNTY	HOPE, TOWN OF	04/30/86(M)
HAMILTON COUNTY	INDIAN LAKE, TOWN OF	12/04/85(M)
HAMILTON COUNTY	INLET, TOWN OF	(NSFHA)
HAMILTON COUNTY	LAKE PLEASANT, TOWN OF	(NSFHA)
HAMILTON COUNTY	LONG LAKE, TOWN OF	09/24/1984 (M)
HAMILTON COUNTY	MOREHOUSE, TOWN OF	(NSFHA)
HAMILTON COUNTY	SPECULATOR, VILLAGE OF	02/06/1984 (M)
HAMILTON COUNTY	WELLS, TOWN OF	06/03/1986 (M)
HERKIMER COUNTY	COLD BROOK, VILLAGE OF	12/20/2000
HERKIMER COUNTY	COLUMBIA, TOWN OF	07/16/1982 (M)
HERKIMER COUNTY	DANUBE, TOWN OF	05/12/1999 (M)
HERKIMER COUNTY	DOLGEVILLE, VILLAGE OF	03/16/1983
HERKIMER COUNTY	FAIRFIELD, TOWN OF	10/18/1988
HERKIMER COUNTY	FRANKFORT, TOWN OF	12/20/2000
HERKIMER COUNTY	FRANKFORT, VILLAGE OF	03/07/2001
HERKIMER COUNTY	GERMAN FLATTS, TOWN OF	05/15/1985 (M)
HERKIMER COUNTY	HERKIMER, TOWN OF	04/17/1985 (M)
HERKIMER COUNTY	HERKIMER, VILLAGE OF	06/17/2002
HERKIMER COUNTY	ILION, VILLAGE OF	09/08/1999
HERKIMER COUNTY	LITCHFIELD, TOWN OF	05/07/2001
HERKIMER COUNTY	LITTLE FALLS, CITY OF	04/04/1983
HERKIMER COUNTY	LITTLE FALLS, TOWN OF	03/28/1980 (M)
HERKIMER COUNTY	MANHEIM, TOWN OF	05/01/1985 (M)
HERKIMER COUNTY	MIDDLEVILLE, VILLAGE OF	07/03/1985 (M)
HERKIMER COUNTY	MOHAWK, VILLAGE OF	09/08/1999
HERKIMER COUNTY	NEWPORT, TOWN OF	06/02/1999
HERKIMER COUNTY	NEWPORT, VILLAGE OF	04/02/1991
HERKIMER COUNTY	NORWAY, TOWN OF	07/03/1985 (M)
HERKIMER COUNTY	OHIO, TOWN OF	09/24/1984 (M)
HERKIMER COUNTY	POLAND, VILLAGE OF	06/02/1999 (M)
HERKIMER COUNTY	RUSSIA, TOWN OF	06/02/1999
HERKIMER COUNTY	SALISBURY, TOWN OF	07/03/1985 (M)
HERKIMER COUNTY	SCHUYLER, TOWN OF	06/20/2001
HERKIMER COUNTY	STARK, TOWN OF	05/15/1985 (M)
HERKIMER COUNTY	WARREN, TOWN OF	(NSFHA)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
HERKIMER COUNTY	WEBB, TOWN OF	07/30/1982 (M)
HERKIMER COUNTY	WEST WINFIELD, VILLAGE OF	07/30/1982 (M)
HERKIMER COUNTY	WINFIELD, TOWN OF	07/30/1982 (M)
JEFFERSON COUNTY	ADAMS, TOWN OF	06/05/1985 (M)
JEFFERSON COUNTY	ADAMS, VILLAGE OF	06/19/1985 (M)
JEFFERSON COUNTY	ALEXANDRIA BAY, VILLAGE OF	04/03/1978
JEFFERSON COUNTY	ALEXANDRIA, TOWN OF	10/15/1985 (M)
JEFFERSON COUNTY	ANTWERP, TOWN OF	04/15/1986 (M)
JEFFERSON COUNTY	ANTWERP, VILLAGE OF	(NSFHA)
JEFFERSON COUNTY	BLACK RIVER, VILLAGE OF	06/05/1989 (M)
JEFFERSON COUNTY	BROWNVILLE, TOWN OF	06/02/1992
JEFFERSON COUNTY	BROWNVILLE, VILLAGE OF	03/18/1986 (M)
JEFFERSON COUNTY	CAPE VINCENT, TOWN OF	06/02/1992
JEFFERSON COUNTY	CAPE VINCENT, VILLAGE OF	04/17/1985 (M)
JEFFERSON COUNTY	CARTHAGE, VILLAGE OF	06/17/1991
JEFFERSON COUNTY	CHAMPION, TOWN OF	06/02/1993
JEFFERSON COUNTY	CHAUMONT, VILLAGE OF	09/08/1999
JEFFERSON COUNTY	CLAYTON, TOWN OF	04/02/1986
JEFFERSON COUNTY	CLAYTON, VILLAGE OF	12/1/1977
JEFFERSON COUNTY	DEFERIET, VILLAGE OF	(NSFHA)
JEFFERSON COUNTY	DEXTER, VILLAGE OF	06/15/1994
JEFFERSON COUNTY	ELLISBURG, TOWN OF	05/18/1992
JEFFERSON COUNTY	ELLISBURG, VILLAGE OF	06/19/1985 (M)
JEFFERSON COUNTY	EVANS MILLS, VILLAGE OF	01/02/1992
JEFFERSON COUNTY	GLEN PARK, VILLAGE OF	(NSFHA)
JEFFERSON COUNTY	HENDERSON, TOWN OF	05/18/1992
JEFFERSON COUNTY	HERRINGS, VILLAGE OF	12/18/1985
JEFFERSON COUNTY	HOUNSFIELD, TOWN OF	05/18/1992
JEFFERSON COUNTY	LERAY, TOWN OF	02/02/1902
JEFFERSON COUNTY	LYME, TOWN OF	09/02/1993
JEFFERSON COUNTY	ORLEANS, TOWN OF	03/01/1978
JEFFERSON COUNTY	PAMELIA, TOWN OF	01/02/1992
JEFFERSON COUNTY	PHILADELPHIA, TOWN OF	06/05/89(M)
JEFFERSON COUNTY	PHILADELPHIA, VILLAGE OF	09/15/1993
JEFFERSON COUNTY	RODMAN, TOWN OF	07/03/1985 (M)
JEFFERSON COUNTY	RUTLAND, TOWN OF	08/18/1992
JEFFERSON COUNTY	SACKETS HARBOR, VILLAGE OF	05/02/1994
JEFFERSON COUNTY	THERESA, TOWN OF	10/15/1985 (M)
JEFFERSON COUNTY	THERESA, VILLAGE OF	10/15/1985 (M)
JEFFERSON COUNTY	WATERTOWN, CITY OF	08/02/1993
JEFFERSON COUNTY	WATERTOWN, TOWN OF	08/02/1993
JEFFERSON COUNTY	WEST CARTHAGE, VILLAGE OF	09/28/1990

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
JEFFERSON COUNTY	WILNA, TOWN OF	01/16/1992
JEFFERSON COUNTY	WORTH, TOWN OF	(NSFHA)
LEWIS COUNTY	CASTORLAND, VILLAGE OF	(NSFHA)
LEWIS COUNTY	CONSTABLEVILLE, VILLAGE OF	07/16/1982 (M)
LEWIS COUNTY	COPENHAGEN, VILLAGE OF	(NSFHA)
LEWIS COUNTY	CROGHAM, VILLAGE OF	05/15/1985 (M)
LEWIS COUNTY	CROGHAN, TOWN OF	05/15/1985 (M)
LEWIS COUNTY	DENMARK, TOWN OF	05/15/1985 (M)
LEWIS COUNTY	DIANA, TOWN OF	09/24/1984 (M)
LEWIS COUNTY	GREIG, TOWN OF	05/15/1985 (M)
LEWIS COUNTY	HARRISBURG, TOWN OF	(NSFHA)
LEWIS COUNTY	HARRISVILLE, VILLAGE OF	09/24/1984 (M)
LEWIS COUNTY	LEWIS, TOWN OF	09/29/1996
LEWIS COUNTY	LEYDEN, TOWN OF	06/19/1985 (M)
LEWIS COUNTY	LOWVILLE, TOWN OF	06/20/2000
LEWIS COUNTY	LOWVILLE, VILLAGE OF	06/20/2000
LEWIS COUNTY	LYONS FALLS, VILLAGE OF	06/19/1985 (M)
LEWIS COUNTY	LYONSDALE, TOWN OF	06/19/1985 (M)
LEWIS COUNTY	MARTINSBURG, TOWN OF	06/19/1985 (M)
LEWIS COUNTY	NEW BREMEN, TOWN OF	05/04/2000
LEWIS COUNTY	OSCEOLA, TOWN OF	06/30/1976 (M)
LEWIS COUNTY	PINCKNEY, TOWN OF	(NSFHA)
LEWIS COUNTY	PORT LEYDEN, VILLAGE OF	06/19/1985 (M)
LEWIS COUNTY	TURIN, TOWN OF	08/02/1994
LEWIS COUNTY	TURIN, VILLAGE OF	07/01/1977 (M)
LEWIS COUNTY	WATSON, TOWN OF	07/19/2000
LEWIS COUNTY	WEST TURIN, TOWN OF	(NSFHA)
LIVINGSTON COUNTY	AVON, TOWN OF	08/15/1978
LIVINGSTON COUNTY	AVON, VILLAGE OF	08/01/1978
LIVINGSTON COUNTY	CALEDONIA, TOWN OF	06/01/1981
LIVINGSTON COUNTY	CALEDONIA, VILLAGE OF	06/01/1981
LIVINGSTON COUNTY	CONESUS, TOWN OF	02/15/1991
LIVINGSTON COUNTY	DANSVILLE, VILLAGE OF	04/05/2010
LIVINGSTON COUNTY	GENESEO, TOWN OF	09/29/1996
LIVINGSTON COUNTY	GENESEO, VILLAGE OF	09/29/1996
LIVINGSTON COUNTY	GROVELAND, TOWN OF	02/15/1991
LIVINGSTON COUNTY	LEICESTER, TOWN OF	01/20/1982
LIVINGSTON COUNTY	LEICESTER, VILLAGE OF	08/27/1982 (M)
LIVINGSTON COUNTY	LIMA, TOWN OF	12/23/1983 (M)
LIVINGSTON COUNTY	LIMA, VILLAGE OF	07/23/1982 (M)
LIVINGSTON COUNTY	LIVONIA, TOWN OF	02/19/1992
LIVINGSTON COUNTY	LIVONIA, VILLAGE OF	06/01/1988 (L)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
LIVINGSTON COUNTY	MOUNT MORRIS, TOWN OF	(NSFHA)
LIVINGSTON COUNTY	MOUNT MORRIS, VILLAGE OF	08/01/1978
LIVINGSTON COUNTY	NORTH DANSVILLE, TOWN OF	04/05/2010
LIVINGSTON COUNTY	NUNDA, TOWN OF	07/03/1985 (M)
LIVINGSTON COUNTY	NUNDA, VILLAGE OF	03/23/1984 (M)
LIVINGSTON COUNTY	OSSIAN, TOWN OF	06/08/1984 (M)
LIVINGSTON COUNTY	PORTAGE,TOWN OF	12/18/1984
LIVINGSTON COUNTY	SPARTA, TOWN OF	04/05/2010
LIVINGSTON COUNTY	SPRINGWATER, TOWN OF	08/24/1984 (M)
LIVINGSTON COUNTY	WEST SPARTA, TOWN OF	04/05/2010
LIVINGSTON COUNTY	YORK, TOWN OF	01/20/1982
MADISON COUNTY	BROOKFIELD, TOWN OF	04/17/1985 (M)
MADISON COUNTY	CANASTOTA , VILLAGE OF	04/15/1988
MADISON COUNTY	CAZENOVIA, TOWN OF	06/19/1985
MADISON COUNTY	CAZENOVIA, VILLAGE OF	06/19/1985
MADISON COUNTY	CHITTENANGO, VILLAGE OF	02/01/1985 (M)
MADISON COUNTY	DE RUYTER, TOWN OF	06/08/1984
MADISON COUNTY	DE RUYTER, VILLAGE OF	08/24/1984 (M)
MADISON COUNTY	EATON, TOWN OF	09/10/1984 (M)
MADISON COUNTY	FENNER, TOWNSHIP OF	02/05/1986
MADISON COUNTY	GEORGETOWN, TOWN OF	11/02/1984 (M)
MADISON COUNTY	HAMILTON, TOWN OF	09/27/2002
MADISON COUNTY	HAMILTON,VILLAGE	09/27/2002
MADISON COUNTY	LEBANON, TOWN OF	04/17/1985 (M)
MADISON COUNTY	LENOX, TOWN OF	06/03/1988
MADISON COUNTY	LINCOLN, TOWN OF	09/04/1985 (M)
MADISON COUNTY	MADISON, TOWN OF	01/19/1983
MADISON COUNTY	MORRISVILLE, VILLAGE OF	04/15/1982
MADISON COUNTY	MUNNSVILLE, VILLAGE OF	09/15/1983
MADISON COUNTY	NELSON, TOWN OF	10/05/1984 (M)
MADISON COUNTY	ONEIDA, CITY OF	02/23/2001
MADISON COUNTY	SMITHFIELD, TOWN OF	04/17/1985 (M)
MADISON COUNTY	STOCKBRIDGE, TOWN OF	(NSFHA)
MADISON COUNTY	SULLIVAN, TOWN OF	05/15/1986
MADISON COUNTY	WAMPSVILLE, VILLAGE OF	(NSFHA)
MONROE COUNTY	BRIGHTON, TOWN OF	08/28/2008
MONROE COUNTY	BROCKPORT, VILLAGE OF	08/28/2008 (M)
MONROE COUNTY	CHILI, TOWN OF	08/28/2008
MONROE COUNTY	CHURCHVILLE, VILLAGE OF	08/28/2008
MONROE COUNTY	CLARKSON, TOWN OF	08/28/2008
MONROE COUNTY	EAST ROCHESTER, VILLAGE OF	08/28/2008 (M)
MONROE COUNTY	FAIRPORT, VILLAGE OF	08/28/2008

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
MONROE COUNTY	GATES, TOWN OF	08/28/2008
MONROE COUNTY	GREECE, TOWN OF	08/28/2008
MONROE COUNTY	HAMLIN, TOWN OF	08/28/2008
MONROE COUNTY	HENRIETTA, TOWN OF	08/28/2008
MONROE COUNTY	HILTON, VILLAGE OF	08/28/2008
MONROE COUNTY	HONEOYE FALLS, VILLAGE OF	08/28/2008
MONROE COUNTY	IRONDEQUOIT, TOWN OF	08/28/2008
MONROE COUNTY	MENDON, TOWN OF	08/28/2008
MONROE COUNTY	OGDEN, TOWN OF	08/28/2008
MONROE COUNTY	PARMA, TOWN OF	08/28/2008
MONROE COUNTY	PENFIELD, TOWN OF	08/28/2008
MONROE COUNTY	PERINTON, TOWN OF	08/28/2008
MONROE COUNTY	PITTSFORD, TOWN OF	08/28/2008
MONROE COUNTY	PITTSFORD, VILLAGE OF	08/28/2008 (M)
MONROE COUNTY	RIGA, TOWN OF	08/28/2008
MONROE COUNTY	ROCHESTER, CITY OF	08/28/2008
MONROE COUNTY	RUSH, TOWN OF	08/28/2008
MONROE COUNTY	SCOTTSVILLE, VILLAGE OF	08/28/2008
MONROE COUNTY	SPENCERPORT, VILLAGE OF	08/28/2008
MONROE COUNTY	SWEDEN, TOWN OF	08/28/2008 (M)
MONROE COUNTY	WEBSTER, TOWN OF	08/28/2008
MONROE COUNTY	WEBSTER, VILLAGE OF	08/28/2008
MONROE COUNTY	WHEATLAND, TOWN OF	08/28/2008
MONTGOMERY COUNTY	AMES, VILLAGE OF	12/4/1985
MONTGOMERY COUNTY	AMSTERDAM, CITY OF	06/19/1985
MONTGOMERY COUNTY	AMSTERDAM, TOWN OF	12/01/1987 (L)
MONTGOMERY COUNTY	CANAJOHARIE, TOWN OF	01/06/1983
MONTGOMERY COUNTY	CANAJOHARIE, VILLAGE OF	11/3/1982
MONTGOMERY COUNTY	CHARLESTON, TOWN OF	10/15/1985 (M)
MONTGOMERY COUNTY	FLORIDA, TOWN OF	12/01/1987 (L)
MONTGOMERY COUNTY	FONDA, VILLAGE OF	07/06/1983
MONTGOMERY COUNTY	FORT JOHNSON, VILLAGE OF	01/19/1983
MONTGOMERY COUNTY	FORT PLAIN, VILLAGE OF	06/17/2002
MONTGOMERY COUNTY	FULTONVILLE, VILLAGE OF	10/15/1982
MONTGOMERY COUNTY	GLEN, TOWN OF	02/19/1986 (M)
MONTGOMERY COUNTY	HAGAMAN, VILLAGE OF	03/18/1986 (M)
MONTGOMERY COUNTY	MINDEN, TOWN OF	01/19/1983
MONTGOMERY COUNTY	MOHAWK, TOWN OF	08/05/1985 (M)
MONTGOMERY COUNTY	NELLISTON, VILLAGE OF	11/3/1982
MONTGOMERY COUNTY	PALATINE BRIDGE, VILLAGE OF	11/17/1982
MONTGOMERY COUNTY	PALATINE, TOWN OF	05/04/1987
MONTGOMERY COUNTY	ROOT, TOWN OF	04/01/1988 (L)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
MONTGOMERY COUNTY	ST. JOHNSVILLE, TOWN OF	03/16/1983
MONTGOMERY COUNTY	ST. JOHNSVILLE, VILLAGE OF	09/29/1989
NASSAU COUNTY	ATLANTIC BEACH, VILLAGE OF	09/11/2009
NASSAU COUNTY	BAXTER ESTATES, VILLAGE OF	09/11/2009
NASSAU COUNTY	BAYVILLE, VILLAGE OF	09/11/2009
NASSAU COUNTY	CEDARHURST, VILLAGE OF	09/11/2009
NASSAU COUNTY	CENTRE ISLAND, VILLAGE OF	09/11/2009
NASSAU COUNTY	COVE NECK, VILLAGE OF	09/11/2009
NASSAU COUNTY	EAST HILLS, VILLAGE OF	(NSFHA)
NASSAU COUNTY	EAST ROCKAWAY, VILLAGE OF	09/11/2009
NASSAU COUNTY	EAST WILLISTON, VILLAGE OF	(NSFHA)
NASSAU COUNTY	FLORAL PARK, VILLAGE OF	(NSFHA)
NASSAU COUNTY	FLOWER HILL, VILLAGE OF	09/11/2009
NASSAU COUNTY	FREEPORT, VILLAGE OF	09/11/2009
NASSAU COUNTY	GARDEN CITY, VILLAGE OF	(NSFHA)
NASSAU COUNTY	GLEN COVE, CITY OF	09/11/2009
NASSAU COUNTY	GREAT NECK ESTATES, VILLAGE OF	09/11/2009
NASSAU COUNTY	GREAT NECK PLAZA, VILLAGE OF	09/11/2009
NASSAU COUNTY	GREAT NECK, VILLAGE OF	09/11/2009
NASSAU COUNTY	HEMPSTEAD, TOWN OF	09/11/2009
NASSAU COUNTY	HEMPSTEAD, VILLAGE OF	(NSFHA)
NASSAU COUNTY	HEWLETT BAY PARK, VILLAGE OF	09/11/2009
NASSAU COUNTY	HEWLETT HARBOR, VILLAGE OF	09/11/2009
NASSAU COUNTY	HEWLETT NECK, VILLAGE OF	09/11/2009
NASSAU COUNTY	ISLAND PARK, VILLAGE OF	09/11/2009
NASSAU COUNTY	KENSINGTON, VILLAGE OF	09/11/2009
NASSAU COUNTY	KINGS POINT, VILLAGE OF	09/11/2009
NASSAU COUNTY	LAKE SUCCESS, VILLAGE OF	(NSFHA)
NASSAU COUNTY	LATTINGTOWN, VILLAGE OF	09/11/2009
NASSAU COUNTY	LAUREL HOLLOW, VILLAGE OF	09/11/2009
NASSAU COUNTY	LAWRENCE, VILLAGE OF	09/11/2009
NASSAU COUNTY	LONG BEACH, CITY OF	09/11/2009
NASSAU COUNTY	LYNBROOK, VILLAGE OF	09/11/2009
NASSAU COUNTY	MALVERNE, VILLAGE OF	09/11/2009
NASSAU COUNTY	MANORHAVEN, VILLAGE OF	09/11/2009
NASSAU COUNTY	MASSAPEQUA PARK, VILLAGE OF	09/11/2009
NASSAU COUNTY	MILL NECK, VILLAGE OF	09/11/2009
NASSAU COUNTY	MINEOLA, VILLAGE OF	(NSFHA)
NASSAU COUNTY	MUNSEY PARK, VILLAGE OF	(NSFHA)
NASSAU COUNTY	NEW HYDE PARK, VILLAGE OF	(NSFHA)
NASSAU COUNTY	NORTH HEMPSTEAD, TOWN OF	09/11/2009
NASSAU COUNTY	NORTH HILLS, VILLAGE OF	(NSFHA)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
NASSAU COUNTY	OYSTER BAY COVE, VILLAGE OF	09/11/2009
NASSAU COUNTY	OYSTER BAY, TOWN OF	09/11/2009
NASSAU COUNTY	PLANDOME HEIGHTS, VILLAGE OF	09/11/2009
NASSAU COUNTY	PLANDOME MANOR, VILLAGE OF	09/11/2009
NASSAU COUNTY	PLANDOME, VILLAGE OF	09/11/2009
NASSAU COUNTY	PORT WASHINGTON NORTH, VILLAG	09/11/2009
NASSAU COUNTY	ROCKVILLE CENTRE, VILLAGE OF	09/11/2009
NASSAU COUNTY	ROSLYN ESTATES, VILLAGE OF	(NSFHA)
NASSAU COUNTY	ROSLYN HARBOR, VILLAGE OF	09/11/2009
NASSAU COUNTY	ROSLYN, VILLAGE OF	09/11/2009
NASSAU COUNTY	RUSSELL GARDENS, VILLAGE OF	09/11/2009
NASSAU COUNTY	SADDLE ROCK, VILLAGE OF	09/11/2009
NASSAU COUNTY	SANDS POINT, VILLAGE OF	09/11/2009
NASSAU COUNTY	SEA CLIFF, VILLAGE OF	09/11/2009
NASSAU COUNTY	STEWART MANOR, VILLAGE OF	(NSFHA)
NASSAU COUNTY	THOMASTON, VILLAGE OF	09/11/2009
NASSAU COUNTY	VALLEY STREAM, VILLAGE OF	09/11/2009
NASSAU COUNTY	WESTBURY, VILLAGE OF	(NSFHA)
NASSAU COUNTY	WOODSBURGH, VILLAGE OF	09/11/2009
NIAGARA COUNTY	BARKER, VILLAGE OF	09/17/2010
NIAGARA COUNTY	CAMBRIA, TOWN OF	09/17/2010
NIAGARA COUNTY	HARTLAND, TOWN OF	09/17/2010 (M)
NIAGARA COUNTY	LEWISTON, TOWN OF	09/17/2010
NIAGARA COUNTY	LEWISTON, VILLAGE OF	(NSFHA)
NIAGARA COUNTY	LOCKPORT, CITY OF	09/17/2010
NIAGARA COUNTY	LOCKPORT, TOWN OF	09/17/2010
NIAGARA COUNTY	MIDDLEPORT, VILLAGE OF	09/17/2010
NIAGARA COUNTY	NEWFANE, TOWN OF	09/17/2010
NIAGARA COUNTY	NIAGARA FALLS, CITY OF	09/17/2010
NIAGARA COUNTY	NIAGARA, TOWN OF	09/17/2010
NIAGARA COUNTY	NORTH TONAWANDA, CITY OF	09/17/2010
NIAGARA COUNTY	PENDLETON, TOWN OF	09/17/2010
NIAGARA COUNTY	PORTER, TOWN OF	09/17/2010
NIAGARA COUNTY	ROYALTON, TOWN OF	09/17/2010
NIAGARA COUNTY	SOMERSET, TOWN OF	09/17/2010
NIAGARA COUNTY	WHEATFIELD, TOWN OF	09/17/2010
NIAGARA COUNTY	WILSON, TOWN OF	09/17/2010
NIAGARA COUNTY	WILSON, VILLAGE OF	09/17/2010
NIAGARA COUNTY	YOUNGSTOWN, VILLAGE OF	09/17/2010
ONEIDA COUNTY	ANNSVILLE, TOWN OF	04/05/1988
ONEIDA COUNTY	AUGUSTA, TOWN OF	05/01/1985 (M)
ONEIDA COUNTY	AVA, TOWN OF	02/01/1985 (M)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ONEIDA COUNTY	BARNEVELD, VILLAGE OF	03/23/1999
ONEIDA COUNTY	BOONVILLE, TOWN OF	07/03/1985 (M)
ONEIDA COUNTY	BOONVILLE, VILLAGE OF	04/17/1985 (M)
ONEIDA COUNTY	BRIDGEWATER, TOWN OF	(NSFHA)
ONEIDA COUNTY	BRIDGEWATER, VILLAGE OF	04/15/1982
ONEIDA COUNTY	CAMDEN, TOWN OF	09/07/1998
ONEIDA COUNTY	CAMDEN, VILLAGE OF	08/16/1988
ONEIDA COUNTY	CLAYVILLE, VILLAGE OF	07/05/1983
ONEIDA COUNTY	CLINTON, VILLAGE OF	05/01/1985
ONEIDA COUNTY	DEERFIELD, TOWN OF	06/02/1999
ONEIDA COUNTY	FLORENCE, TOWN OF	04/17/1985 (M)
ONEIDA COUNTY	FLOYD, TOWN OF	03/15/1984
ONEIDA COUNTY	FORESTPORT, TOWN OF	04/17/1985 (M)
ONEIDA COUNTY	HOLLAND PATENT, VILLAGE OF	05/21/2001
ONEIDA COUNTY	KIRKLAND, TOWN OF	04/03/1985
ONEIDA COUNTY	LEE, TOWN OF	08/03/1998
ONEIDA COUNTY	MARCY, TOWN OF	06/01/1984
ONEIDA COUNTY	MARSHALL, TOWN OF	09/30/1982
ONEIDA COUNTY	NEW HARTFORD, TOWN OF	04/18/1983
ONEIDA COUNTY	NEW HARTFORD, VILLAGE OF	07/05/1983
ONEIDA COUNTY	NEW YORK MILLS, VILLAGE OF	05/04/2000
ONEIDA COUNTY	ONEIDA CASTLE, VILLAGE OF	07/04/1989
ONEIDA COUNTY	ORISKANY FALLS, VILLAGE OF	01/19/1983
ONEIDA COUNTY	ORISKANY, VILLAGE OF	09/15/1983
ONEIDA COUNTY	PARIS, TOWN OF	09/15/1983
ONEIDA COUNTY	PROSPECT, VILLAGE OF	11/20/2000
ONEIDA COUNTY	REMSEN, TOWN OF	05/01/1985 (M)
ONEIDA COUNTY	REMSEN, VILLAGE OF	09/24/1984 (M)
ONEIDA COUNTY	ROME, CITY OF	09/21/1998
ONEIDA COUNTY	SANGERFIELD, TOWN OF	06/05/1985
ONEIDA COUNTY	SHERRILL, CITY OF	09/15/1983
ONEIDA COUNTY	STEUBEN, TOWN OF	09/24/1984 (M)
ONEIDA COUNTY	SYLVAN BEACH, VILLAGE OF	06/02/1999
ONEIDA COUNTY	TRENTON, TOWN OF	09/07/1998
ONEIDA COUNTY	UTICA, CITY OF	02/01/1984
ONEIDA COUNTY	VERNON, TOWN OF	08/16/1988
ONEIDA COUNTY	VERNON, VILLAGE OF	04/15/1988
ONEIDA COUNTY	VERONA, TOWN OF	10/20/1999
ONEIDA COUNTY	VIENNA, TOWN OF	10/20/1999
ONEIDA COUNTY	WATERVILLE, VILLAGE OF	08/02/1982
ONEIDA COUNTY	WESTERN, TOWN OF	05/04/1989
ONEIDA COUNTY	WESTMORELAND, TOWN OF	03/02/1983

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ONEIDA COUNTY	WHITESBORO, VILLAGE OF	05/04/2000
ONEIDA COUNTY	WHITESTOWN, TOWN OF	05/04/2000
ONEIDA COUNTY	YORKVILLE, VILLAGE OF	05/04/2000
ONONDAGA COUNTY	BALDWINSVILLE, VILLAGE OF	03/01/1984
ONONDAGA COUNTY	CAMILLUS, TOWN OF	05/18/1999
ONONDAGA COUNTY	CAMILLUS, VILLAGE OF	05/18/1999
ONONDAGA COUNTY	CICERO, TOWN OF	09/15/1994
ONONDAGA COUNTY	CLAY, TOWN OF	03/16/1992
ONONDAGA COUNTY	DEWITT, TOWN OF	03/01/1979
ONONDAGA COUNTY	EAST SYRACUSE, VILLAGE OF	08/03/1981
ONONDAGA COUNTY	ELBRIDGE, TOWN OF	08/16/1982
ONONDAGA COUNTY	ELBRIDGE, VILLAGE OF	08/16/1982
ONONDAGA COUNTY	FABIUS, TOWN OF	04/30/1986 (M)
ONONDAGA COUNTY	FAYETTEVILLE, VILLAGE OF	04/17/1985
ONONDAGA COUNTY	GEDDES, TOWN OF	02/17/1982
ONONDAGA COUNTY	JORDAN, VILLAGE OF	08/16/1982
ONONDAGA COUNTY	LAFAYETTE, TOWN OF	04/03/1985
ONONDAGA COUNTY	LIVERPOOL, VILLAGE OF	02/04/1981
ONONDAGA COUNTY	LYSANDER, TOWN OF	02/04/1983
ONONDAGA COUNTY	MANLIUS, TOWN OF	09/17/1992
ONONDAGA COUNTY	MANLIUS, VILLAGE OF	08/01/1984
ONONDAGA COUNTY	MARCELLUS, TOWN OF	08/16/1982
ONONDAGA COUNTY	MARCELLUS, VILLAGE OF	06/01/1982
ONONDAGA COUNTY	MINOA, VILLAGE OF	09/02/1982
ONONDAGA COUNTY	NORTH SYRACUSE, VILLAGE OF	(NSFHA)
ONONDAGA COUNTY	ONONDAGA, TOWN OF	06/17/1991
ONONDAGA COUNTY	OTISCO, TOWN OF	06/03/1986 (M)
ONONDAGA COUNTY	POMPEY, TOWN OF	10/8/1982
ONONDAGA COUNTY	SALINA, TOWN OF	08/16/1982
ONONDAGA COUNTY	SKANEATELES, TOWN OF	06/01/1982
ONONDAGA COUNTY	SKANEATELES, VILLAGE OF	02/17/1982
ONONDAGA COUNTY	SOLVAY, VILLAGE OF	(NSFHA)
ONONDAGA COUNTY	SPAFFORD, TOWN OF	04/30/1986 (M)
ONONDAGA COUNTY	SYRACUSE, CITY OF	05/15/1986
ONONDAGA COUNTY	TULLY, TOWN OF	04/30/1986 (M)
ONONDAGA COUNTY	TULLY, VILLAGE OF	01/19/1983
ONONDAGA COUNTY	VAN BUREN, TOWN OF	03/01/1984
ONTARIO COUNTY	BLOOMFIELD, VILLAGE OF	8/15/1983
ONTARIO COUNTY	BRISTOL, TOWN OF	01/20/1984 (M)
ONTARIO COUNTY	CANADICE, TOWN OF	05/15/1984
ONTARIO COUNTY	CANANDAIGUA, CITY OF	09/24/1982
ONTARIO COUNTY	CANANDAIGUA, TOWN OF	03/03/1997

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ONTARIO COUNTY	CLIFTON SPRINGS, VILLAGE OF	07/23/1982 (M)
ONTARIO COUNTY	EAST BLOOMFIELD, TOWN OF	08/15/1983
ONTARIO COUNTY	FARMINGTON, TOWN OF	09/30/1983
ONTARIO COUNTY	GENEVA, CITY OF	04/15/1982
ONTARIO COUNTY	GENEVA, TOWN OF	02/15/1978
ONTARIO COUNTY	GORHAM, TOWN OF	12/5/1996
ONTARIO COUNTY	HOPEWELL, TOWN OF	02/27/1984 (M)
ONTARIO COUNTY	MANCHESTER, TOWN OF	03/09/1984 (M)
ONTARIO COUNTY	MANCHESTER, VILLAGE OF	01/20/1984 (M)
ONTARIO COUNTY	NAPLES, TOWN OF	06/08/1984 (M)
ONTARIO COUNTY	NAPLES, VILLAGE OF	09/30/1977
ONTARIO COUNTY	PHELPS, TOWN OF	12/03/1982 (M)
ONTARIO COUNTY	PHELPS, VILLAGE OF	01/20/1984 (M)
ONTARIO COUNTY	RICHMOND, TOWN OF	12/18/1984
ONTARIO COUNTY	SENECA, TOWN OF	06/22/1984(M)
ONTARIO COUNTY	SHORTSVILLE, VILLAGE OF	09/24/1984 (M)
ONTARIO COUNTY	SOUTH BRISTOL, TOWN OF	05/18/1998
ONTARIO COUNTY	VICTOR, TOWN OF	09/30/1983
ONTARIO COUNTY	VICTOR, VILLAGE OF	05/17/2004
ONTARIO COUNTY	WEST BLOOMFIELD, TOWN OF	06/01/1978
ORANGE COUNTY	BLOOMING GROVE, TOWN OF	08/03/2009
ORANGE COUNTY	CHESTER, TOWN OF	08/03/2009
ORANGE COUNTY	CHESTER, VILLAGE OF	08/03/2009
ORANGE COUNTY	CORNWALL ON THE HUDSON, VILLA	08/03/2009
ORANGE COUNTY	CORNWALL, TOWN OF	08/03/2009
ORANGE COUNTY	CRAWFORD, TOWN OF	08/03/2009
ORANGE COUNTY	DEER PARK, TOWN OF	08/03/2009
ORANGE COUNTY	FLORIDA, VILLAGE OF	08/03/2009
ORANGE COUNTY	GOSHEN, TOWN OF	08/03/2009
ORANGE COUNTY	GOSHEN, VILLAGE OF	08/03/2009
ORANGE COUNTY	GREENVILLE, TOWN OF	08/03/2009
ORANGE COUNTY	GREENWOOD LAKE, VILLAGE OF	08/03/2009
ORANGE COUNTY	HAMPTONBURGH, TOWN OF	08/03/2009
ORANGE COUNTY	HARRIMAN, VILLAGE OF	08/03/2009
ORANGE COUNTY	HIGHLAND FALLS, VILLAGE OF	08/03/2009
ORANGE COUNTY	HIGHLANDS, TOWNSHIP OF	08/03/2009
ORANGE COUNTY	KIRYAS JOEL, VILLAGE OF	08/03/2009
ORANGE COUNTY	MAYBROOK, VILLAGE OF	08/03/2009 (M)
ORANGE COUNTY	MIDDLETOWN, CITY OF	08/03/2009
ORANGE COUNTY	MINISINK, TOWN OF	08/03/2009
ORANGE COUNTY	MONROE, TOWN OF	08/03/2009
ORANGE COUNTY	MONROE, VILLAGE OF	08/03/2009

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ORANGE COUNTY	MONTGOMERY, TOWN OF	08/03/2009
ORANGE COUNTY	MONTGOMERY, VILLAGE OF	08/03/2009
ORANGE COUNTY	MOUNT HOPE, TOWN OF	08/03/2009 (M)
ORANGE COUNTY	NEW WINDSOR, TOWN OF	08/03/2009
ORANGE COUNTY	NEWBURGH, CITY OF	08/03/2009
ORANGE COUNTY	NEWBURGH, TOWN OF	08/03/2009
ORANGE COUNTY	PORT JERVIS, CITY OF	08/03/2009
ORANGE COUNTY	SOUTH BLOOMING GROVE, VILLAGE	08/03/2009
ORANGE COUNTY	TUXEDO PARK, VILLAGE OF	08/03/2009
ORANGE COUNTY	TUXEDO, TOWN OF	08/03/2009
ORANGE COUNTY	UNIONVILLE, VILLAGE OF	08/03/2009 (M)
ORANGE COUNTY	WALDEN, VILLAGE OF	08/03/2009
ORANGE COUNTY	WALLKILL, TOWN OF	08/03/2009
ORANGE COUNTY	WARWICK, TOWN OF	08/03/2009
ORANGE COUNTY	WARWICK, VILLAGE OF	08/03/2009
ORANGE COUNTY	WASHINGTONVILLE, VILLAGE OF	08/03/2009
ORANGE COUNTY	WAWAYANDA, TOWN OF	08/03/2009
ORANGE COUNTY	WOODBURY, VILLAGE OF	08/03/2009
ORLEANS COUNTY	ALBION, TOWN OF	08/08/1980 (M)
ORLEANS COUNTY	ALBION, VILLAGE OF	11/30/1979 (M)
ORLEANS COUNTY	BARRE, TOWN OF	10/15/1981 (M)
ORLEANS COUNTY	CARLTON, TOWN OF	11/1/1978
ORLEANS COUNTY	CLARENDON,TOWN OF	(NSFHA)
ORLEANS COUNTY	GAINES, TOWN OF	06/08/1984 (M)
ORLEANS COUNTY	HOLLEY, VILLAGE OF	11/30/1979 (M)
ORLEANS COUNTY	KENDALL, TOWN OF	05/01/1978
ORLEANS COUNTY	LYNDONVILLE, VILLAGE OF	09/16/1981
ORLEANS COUNTY	MEDINA, VILLAGE OF	03/28/1980 (M)
ORLEANS COUNTY	MURRAY, TOWN OF	03/21/1980 (M)
ORLEANS COUNTY	RIDGEWAY,TOWN OF	09/14/1979 (M)
ORLEANS COUNTY	SHELBY,TOWN OF	12/23/1983 (M)
ORLEANS COUNTY	YATES, TOWN OF	09/29/1978
OSWEGO COUNTY	ALBION, TOWN OF	04/15/1986 (M)
OSWEGO COUNTY	ALTMAR, VILLAGE OF	02/05/1986 (M)
OSWEGO COUNTY	AMBOY, TOWN OF	03/01/1988 (L)
OSWEGO COUNTY	BOYLSTON, TOWN OF	(NSFHA)
OSWEGO COUNTY	CENTRAL SQUARE,VILLAGE OF	(NSFHA)
OSWEGO COUNTY	CLEVELAND, VILLAGE OF	06/01/1982
OSWEGO COUNTY	CONSTANTIA, TOWN OF	11/3/1982
OSWEGO COUNTY	FULTON, CITY OF	04/15/1982
OSWEGO COUNTY	GRANBY, TOWN OF	09/16/1982
OSWEGO COUNTY	HANNIBAL, TOWN OF	02/01/1988 (L)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
OSWEGO COUNTY	HANNIBAL, VILLAGE OF	04/01/1987 (L)
OSWEGO COUNTY	HASTINGS, TOWN OF	01/19/1983
OSWEGO COUNTY	LACONA, VILLAGE OF	05/11/1979 (M)
OSWEGO COUNTY	MEXICO, TOWN OF	10/15/1981
OSWEGO COUNTY	MEXICO, VILLAGE OF	10/15/1981
OSWEGO COUNTY	MINETTO, TOWN OF	09/30/1981
OSWEGO COUNTY	NEW HAVEN, TOWN OF	11/2/1995
OSWEGO COUNTY	ORWELL, TOWN OF	02/19/1986
OSWEGO COUNTY	OSWEGO, CITY OF	11/22/1999
OSWEGO COUNTY	OSWEGO, TOWN OF	06/20/2001
OSWEGO COUNTY	PALERMO, TOWN OF	03/01/1988
OSWEGO COUNTY	PARISH, TOWN OF	04/15/1986 (M)
OSWEGO COUNTY	PARISH, VILLAGE OF	02/19/1986 (M)
OSWEGO COUNTY	PHOENIX, VILLAGE OF	02/17/1982
OSWEGO COUNTY	PULASKI, VILLAGE OF	09/02/1982
OSWEGO COUNTY	REDFIELD, TOWN OF	04/01/1991 (L)
OSWEGO COUNTY	RICHLAND, TOWN OF	07/17/1995
OSWEGO COUNTY	SANDY CREEK, TOWN OF	07/17/1995
OSWEGO COUNTY	SANDY CREEK, VILLAGE OF	05/11/1979 (M)
OSWEGO COUNTY	SCHROEPPEL, TOWN OF	08/02/1982
OSWEGO COUNTY	SCRIBA, TOWN OF	06/06/2001
OSWEGO COUNTY	VOLNEY, TOWN OF	04/15/1982
OSWEGO COUNTY	WEST MONROE, TOWN OF	01/20/1982
OSWEGO COUNTY	WILLIAMSTOWN, TOWN OF	03/01/1988
OTSEGO COUNTY	BURLINGTON, TOWN OF	10/21/1983 (M)
OTSEGO COUNTY	BUTTERNUTS, TOWN OF	12/23/1983 (M)
OTSEGO COUNTY	CHERRY VALLEY, TOWN OF	02/01/1988 (L)
OTSEGO COUNTY	CHERRY VALLEY, VILLAGE OF	01/03/1986 (M)
OTSEGO COUNTY	COOPERSTOWN, VILLAGE OF	05/04/2000
OTSEGO COUNTY	DECATUR, TOWN OF	06/18/1987
OTSEGO COUNTY	EDMESTON, TOWN OF	06/01/1987 (L)
OTSEGO COUNTY	EXETER, TOWN OF	11/18/1983 (M)
OTSEGO COUNTY	GILBERTSVILLE, VILLAGE OF	11/01/1985 (M)
OTSEGO COUNTY	HARTWICK, TOWN OF	11/04/1983 (M)
OTSEGO COUNTY	LAURENS, TOWN OF	05/15/1985 (M)
OTSEGO COUNTY	LAURENS, VILLAGE OF	04/17/1987 (M)
OTSEGO COUNTY	MARYLAND, TOWN OF	06/03/1986 (M)
OTSEGO COUNTY	MIDDLEFIELD, TOWN OF	06/01/1988 (L)
OTSEGO COUNTY	MILFORD, TOWN OF	05/19/1987 (M)
OTSEGO COUNTY	MILFORD, VILLAGE OF	11/18/1983
OTSEGO COUNTY	MORRIS, TOWN OF	01/03/1986 (M)
OTSEGO COUNTY	MORRIS, VILLAGE OF	12/04/1985 (M)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
OTSEGO COUNTY	NEW LISBON, TOWN OF	11/18/1983 (M)
OTSEGO COUNTY	ONEONTA, CITY OF	09/29/1978
OTSEGO COUNTY	ONEONTA, TOWN OF	10/17/1986
OTSEGO COUNTY	OTEGO, TOWN OF	02/04/1987
OTSEGO COUNTY	OTEGO, VILLAGE OF	11/5/1986
OTSEGO COUNTY	OTSEGO, TOWN OF	06/01/1987 (L)
OTSEGO COUNTY	PITTSFIELD, TOWN OF	11/04/1983 (M)
OTSEGO COUNTY	PLAINFIELD, TOWN OF	11/04/1983 (M)
OTSEGO COUNTY	RICHFIELD SPRINGS, VILLAGE OF	01/03/1986 (M)
OTSEGO COUNTY	RICHFIELD, TOWN OF	04/15/1986 (M)
OTSEGO COUNTY	ROSEBOOM, TOWN OF	06/01/1988
OTSEGO COUNTY	SPRINGFIELD, TOWN OF	06/01/1987 (L)
OTSEGO COUNTY	UNADILLA, TOWN OF	09/30/1987
OTSEGO COUNTY	UNADILLA, VILLAGE OF	09/30/1987
OTSEGO COUNTY	WESTFORD, TOWN OF	06/01/1987 (L)
OTSEGO COUNTY	WORCESTER, TOWN OF	06/01/1987 (L)
PUTNAM COUNTY	BREWSTER, VILLAGE OF	09/18/1986
PUTNAM COUNTY	CARMEL,TOWN OF	10/19/2001
PUTNAM COUNTY	COLD SPRING, VILLAGE OF	03/15/1984
PUTNAM COUNTY	KENT, TOWN OF	09/04/1986
PUTNAM COUNTY	NELSONVILLE, VILLAGE OF	09/10/1984 (M)
PUTNAM COUNTY	PATTERSON, TOWN OF	07/03/1986
PUTNAM COUNTY	PHILIPSTOWN,TOWN OF	06/18/1987
PUTNAM COUNTY	PUTNAM VALLEY, TOWN OF	06/20/2001
PUTNAM COUNTY	SOUTHEAST, TOWN OF	09/04/1986
RENSSELAER COUNTY	BERLIN, TOWN OF	08/17/1979 (M)
RENSSELAER COUNTY	BRUNSWICK, TOWN OF	12/6/2000
RENSSELAER COUNTY	CASTLETON-ON-HUDSON, VILLAGE O	11/15/1984
RENSSELAER COUNTY	EAST GREENBUSH, TOWN OF	03/18/1980
RENSSELAER COUNTY	EAST NASSAU, VILLAGE OF	09/05/1984
RENSSELAER COUNTY	GRAFTON, TOWN OF	10/13/1978 (M)
RENSSELAER COUNTY	HOOSICK FALLS, VILLAGE OF	02/04/2005
RENSSELAER COUNTY	HOOSICK, TOWN OF	08/01/1987 (L)
RENSSELAER COUNTY	NASSAU, TOWN OF	09/05/1984
RENSSELAER COUNTY	NASSAU, VILLAGE OF	05/18/1979 (M)
RENSSELAER COUNTY	NORTH GREENBUSH,TOWN OF	06/18/1980
RENSSELAER COUNTY	PETERSBURG, TOWN OF	09/01/1978 (M)
RENSSELAER COUNTY	PITTSTOWN, TOWN OF	09/05/1990
RENSSELAER COUNTY	POESTENKILL, TOWN OF	09/02/1981
RENSSELAER COUNTY	RENSSELAER, CITY OF	03/18/1980
RENSSELAER COUNTY	SAND LAKE, TOWN OF	05/15/1980
RENSSELAER COUNTY	SCHAGHTICOKE, TOWN OF	07/16/1984

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
RENSSELAER COUNTY	SCHAGHTICOKE, VILLAGE OF	06/05/1985
RENSSELAER COUNTY	SCHODACK, TOWN OF	08/15/1984
RENSSELAER COUNTY	STEPHENTOWN, TOWN OF	08/03/1981
RENSSELAER COUNTY	TROY, CITY OF	03/18/1980
RENSSELAER COUNTY	VALLEY FALLS, VILLAGE OF	06/05/1985
RICHMOND COUNTY/QUEENS COUNTY/NEW YORK COUNTY/KINGS COUNTY/BRONX COUNTY	NEW YORK, CITY OF	09/05/2007
ROCKLAND COUNTY	CHESTNUT RIDGE, VILLAGE OF	09/16/1988
ROCKLAND COUNTY	CLARKSTOWN, TOWN OF	05/21/2001
ROCKLAND COUNTY	GRAND VIEW-ON-HUDSON, VILLAGE	10/15/1981
ROCKLAND COUNTY	HAVERSTRAW, TOWN OF	01/06/1982
ROCKLAND COUNTY	HAVERSTRAW, VILLAGE OF	09/02/1981
ROCKLAND COUNTY	HILLBURN, VILLAGE OF	09/20/1996
ROCKLAND COUNTY	KASER, VILLAGE OF	01/01/2050
ROCKLAND COUNTY	MONTEBELLO, VILLAGE OF	01/18/1989
ROCKLAND COUNTY	NEW HEMPSTEAD, VILLAGE OF	12/16/1988
ROCKLAND COUNTY	NEW SQUARE, VILLAGE OF	(NSFHA)
ROCKLAND COUNTY	NYACK, VILLAGE OF	12/4/1985
ROCKLAND COUNTY	ORANGETOWN, TOWN OF	08/02/1982
ROCKLAND COUNTY	PIERMONT, VILLAGE OF	11/17/1982
ROCKLAND COUNTY	POMONA, VILLAGE OF	04/15/1982
ROCKLAND COUNTY	RAMAPO, TOWN OF	02/02/1989
ROCKLAND COUNTY	SLOATSBURG, VILLAGE OF	01/06/1982
ROCKLAND COUNTY	SOUTH NYACK, VILLAGE OF	11/4/1981
ROCKLAND COUNTY	SPRING VALLEY, VILLAGE OF	08/16/1988
ROCKLAND COUNTY	STONY POINT, TOWN OF	09/30/1981
ROCKLAND COUNTY	SUFFERN, VILLAGE OF	03/28/1980
ROCKLAND COUNTY	UPPER NYACK, VILLAGE OF	(NSFHA)
ROCKLAND COUNTY	WESLEY HILLS, VILLAGE OF	09/16/1988
ROCKLAND COUNTY	WEST HAVERSTRAW, VILLAGE OF	09/30/1981
SARATOGA COUNTY	BALLSTON SPA, VILLAGE OF	08/16/1995
SARATOGA COUNTY	BALLSTON, TOWN OF	08/16/1995
SARATOGA COUNTY	CHARLTON, TOWN OF	08/16/1995
SARATOGA COUNTY	CLIFTON PARK, TOWN OF	08/16/1995
SARATOGA COUNTY	CORINTH, TOWN OF	08/16/1995
SARATOGA COUNTY	CORINTH, VILLAGE OF	08/16/1995
SARATOGA COUNTY	DAY, TOWN OF	(NSFHA)
SARATOGA COUNTY	GALWAY, TOWN OF	08/16/1995
SARATOGA COUNTY	GREENFIELD, TOWN OF	08/16/1995
SARATOGA COUNTY	HADLEY, TOWN OF	08/16/1995

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
SARATOGA COUNTY	HALFMOON, TOWN OF	08/16/1995
SARATOGA COUNTY	MALTA, TOWN OF	08/16/1995
SARATOGA COUNTY	MECHANICVILLE, CITY OF	08/16/1995
SARATOGA COUNTY	MILTON, TOWN OF	08/16/1995
SARATOGA COUNTY	MOREAU, TOWN OF	08/16/1995
SARATOGA COUNTY	NORTHUMBERLAND, TOWN OF	08/16/1995
SARATOGA COUNTY	PROVIDENCE, TOWN OF	08/16/1995
SARATOGA COUNTY	ROUND LAKE, VILLAGE OF	08/16/1995
SARATOGA COUNTY	SARATOGA SPRINGS, CITY OF	08/16/1995
SARATOGA COUNTY	SARATOGA, TOWN OF	08/16/1995
SARATOGA COUNTY	SCHUYLERVILLE, VILLAGE OF	08/16/1995
SARATOGA COUNTY	SOUTH GLENS FALLS, VILLAGE OF	08/16/1995
SARATOGA COUNTY	STILLWATER, TOWN OF	08/16/1995
SARATOGA COUNTY	STILLWATER, VILLAGE OF	08/16/1995
SARATOGA COUNTY	VICTORY, VILLAGE OF	08/16/1995
SARATOGA COUNTY	WATERFORD, TOWN OF	08/16/1995
SARATOGA COUNTY	WATERFORD, VILLAGE OF	08/16/1995
SARATOGA COUNTY	WILTON,TOWN OF	(NSFHA)
SCHENECTADY COUNTY	DELANSON, VILLAGE OF	05/25/1984 (M)
SCHENECTADY COUNTY	DUANESBURG, TOWN OF	02/17/1989
SCHENECTADY COUNTY	GLENVILLE,TOWN OF	05/04/1987
SCHENECTADY COUNTY	NISKAYUNA, TOWN OF	03/01/1978
SCHENECTADY COUNTY	PRINCETOWN, TOWN OF	07/01/1988 (L)
SCHENECTADY COUNTY	ROTTERDAM, TOWN OF	06/15/1984
SCHENECTADY COUNTY	SCHENECTADY, CITY OF	09/30/1983
SCHENECTADY COUNTY	SCOTIA, VILLAGE OF	06/01/1984
SCHOHARIE COUNTY	BLENHEIM, TOWN OF	04/02/2004
SCHOHARIE COUNTY	BROOME, TOWN OF	04/02/2004
SCHOHARIE COUNTY	CARLISLE, TOWN OF	04/02/2004
SCHOHARIE COUNTY	COBLESKILL, TOWN OF	04/02/2004
SCHOHARIE COUNTY	COBLESKILL, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	CONESVILLE, TOWN OF	04/02/2004
SCHOHARIE COUNTY	ESPERANCE, TOWN OF	04/02/2004
SCHOHARIE COUNTY	ESPERANCE, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	FULTON, TOWN OF	04/02/2004
SCHOHARIE COUNTY	GILBOA, TOWN OF	04/02/2004
SCHOHARIE COUNTY	JEFFERSON, TOWN OF	04/02/2004
SCHOHARIE COUNTY	MIDDLEBURGH, TOWN OF	04/02/2004
SCHOHARIE COUNTY	MIDDLEBURGH, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	RICHMONDVILLE, TOWN OF	04/02/2004
SCHOHARIE COUNTY	RICHMONDVILLE, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	SCHOHARIE, TOWN OF	04/02/2004

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
SCHOHARIE COUNTY	SCHOHARIE, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	SEWARD, TOWN OF	04/02/2004
SCHOHARIE COUNTY	SHARON SPRING, VILLAGE OF	04/02/2004 (M)
SCHOHARIE COUNTY	SHARON, TOWN OF	04/02/2004
SCHOHARIE COUNTY	SUMMIT, TOWN OF	04/02/2004
SCHOHARIE COUNTY	WRIGHT, TOWN OF	04/02/2004
SCHUYLER COUNTY	BURDETT, VILLAGE OF	06/01/1988 (L)
SCHUYLER COUNTY	CATHARINE, TOWN OF	04/20/1984 (M)
SCHUYLER COUNTY	CAYUTA, TOWN OF	09/24/1984 (M)
SCHUYLER COUNTY	DIX, TOWN OF	10/29/1982 (M)
SCHUYLER COUNTY	HECTOR, TOWN OF	07/20/1984 (M)
SCHUYLER COUNTY	MONTOUR FALLS, VILLAGE OF	09/15/1983
SCHUYLER COUNTY	MONTOUR, TOWN OF	03/01/1988 (L)
SCHUYLER COUNTY	ODESSA, VILLAGE OF	04/20/1984 (M)
SCHUYLER COUNTY	ORANGE, TOWN OF	04/20/1984 (M)
SCHUYLER COUNTY	READING, TOWN OF	(NSFHA)
SCHUYLER COUNTY	TYRONE, TOWN OF	07/06/1984 (M)
SCHUYLER COUNTY	WATKINS GLEN, VILLAGE OF	07/17/1978
SENECA COUNTY	COVERT, TOWN OF	06/08/1984 (M)
SENECA COUNTY	FAYETTE, TOWN OF	01/15/1988
SENECA COUNTY	LODI, TOWN OF	01/15/1988
SENECA COUNTY	LODI, VILLAGE OF	(NSFHA)
SENECA COUNTY	OVID, TOWN OF	01/15/1988
SENECA COUNTY	ROMULUS, TOWN OF	06/05/1985 (M)
SENECA COUNTY	SENECA FALLS, TOWN OF	08/03/1981
SENECA COUNTY	SENECA FALLS, VILLAGE OF	08/03/1981
SENECA COUNTY	TYRE, TOWN OF	08/31/1979 (M)
SENECA COUNTY	VARICK, TOWN OF	12/17/1987
SENECA COUNTY	WATERLOO, TOWN OF	09/16/1981
SENECA COUNTY	WATERLOO, VILLAGE OF	08/03/1981
ST. LAWRENCE COUNTY	BRASHER, TOWN OF	01/03/1986 (M)
ST. LAWRENCE COUNTY	CANTON, TOWN OF	08/17/1998
ST. LAWRENCE COUNTY	CANTON, VILLAGE OF	05/02/1994
ST. LAWRENCE COUNTY	CLARE, TOWN OF	07/16/1982 (M)
ST. LAWRENCE COUNTY	CLIFTON, CITY OF	05/15/1986 (M)
ST. LAWRENCE COUNTY	COLTON, TOWN OF	05/01/1985 (M)
ST. LAWRENCE COUNTY	DE KALB, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	DE PEYSTER, TOWN OF	07/23/1982 (M)
ST. LAWRENCE COUNTY	EDWARDS, TOWN OF	07/30/1982 (M)
ST. LAWRENCE COUNTY	EDWARDS, VILLAGE OF	07/23/1982 (M)
ST. LAWRENCE COUNTY	FINE, TOWN OF	05/01/1985 (M)
ST. LAWRENCE COUNTY	FOWLER, TOWN OF	06/05/1989 (M)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ST. LAWRENCE COUNTY	GOUVERNEUR, TOWN OF	08/06/1982 (M)
ST. LAWRENCE COUNTY	GOUVERNEUR, VILLAGE OF	03/03/1997
ST. LAWRENCE COUNTY	HAMMOND, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	HERMON, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	HERMON, VILLAGE OF	08/03/1998
ST. LAWRENCE COUNTY	HEUVELTON, VILLAGE OF	04/30/1986 (M)
ST. LAWRENCE COUNTY	HOPKINTON, TOWN OF	11/12/1982 (M)
ST. LAWRENCE COUNTY	LAWRENCE, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	LISBON, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	LOUISVILLE, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	MACOMB, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	MADRID, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	MASSENA, TOWN OF	06/17/1986 (M)
ST. LAWRENCE COUNTY	MASSENA, VILLAGE OF	11/5/1980
ST. LAWRENCE COUNTY	MORRISTOWN, TOWN OF	08/06/1982 (M)
ST. LAWRENCE COUNTY	MORRISTOWN, VILLAGE OF	12/02/1980 (M)
ST. LAWRENCE COUNTY	NORFOLK, TOWN OF	04/15/1986 (M)
ST. LAWRENCE COUNTY	NORWOOD, VILLAGE OF	04/30/1986 (M)
ST. LAWRENCE COUNTY	OGDENSBURG, CITY OF	11/5/1980
ST. LAWRENCE COUNTY	OSWEGATCHIE, TOWN OF	05/01/1985 (M)
ST. LAWRENCE COUNTY	PARISHVILLE, TOWN OF	07/30/1982 (M)
ST. LAWRENCE COUNTY	PIERCEFIELD, TOWN OF	01/06/1984 (M)
ST. LAWRENCE COUNTY	PIERREPONT, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	PITCAIRN, TOWN OF	08/13/1982 (M)
ST. LAWRENCE COUNTY	POTSDAM, VILLAGE OF	01/05/1996
ST. LAWRENCE COUNTY	POTSDAM,TOWN OF	03/04/1986 (M)
ST. LAWRENCE COUNTY	RENSSELAER FALLS, VILLAGE OF	01/06/1984 (M)
ST. LAWRENCE COUNTY	RICHVILLE, VILLAGE OF	01/06/1984 (M)
ST. LAWRENCE COUNTY	ROSSIE, TOWN OF	07/30/1982 (M)
ST. LAWRENCE COUNTY	RUSSELL, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	STOCKHOLM, TOWN OF	04/15/1986 (M)
ST. LAWRENCE COUNTY	WADDINGTON, TOWN OF	04/15/1986 (M)
ST. LAWRENCE COUNTY	WADDINGTON, VILLAGE OF	05/11/1979 (M)
STEUBEN COUNTY	ADDISON, TOWN OF	12/18/1984
STEUBEN COUNTY	ADDISON, VILLAGE OF	06/15/1981
STEUBEN COUNTY	ARKPORT, VILLAGE OF	03/04/1980
STEUBEN COUNTY	AVOCA, TOWN OF	02/05/1992
STEUBEN COUNTY	AVOCA, VILLAGE OF	05/16/1983
STEUBEN COUNTY	BATH, TOWN OF	05/02/1983
STEUBEN COUNTY	BATH, VILLAGE OF	03/16/1983
STEUBEN COUNTY	BRADFORD, TOWN OF	09/24/1984 (M)
STEUBEN COUNTY	CAMERON, TOWN OF	05/15/1991

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
STEUBEN COUNTY	CAMPBELL, TOWN OF	06/11/1982
STEUBEN COUNTY	CANISTEO, TOWN OF	12/18/1984
STEUBEN COUNTY	CANISTEO, VILLAGE OF	05/18/1979 (M)
STEUBEN COUNTY	CATON, TOWN OF	03/23/1984 (M)
STEUBEN COUNTY	COHOCTON, TOWN OF	05/16/1983
STEUBEN COUNTY	COHOCTON, VILLAGE OF	05/16/1983
STEUBEN COUNTY	CORNING, CITY OF	09/27/2002
STEUBEN COUNTY	CORNING, TOWN OF	09/27/2002
STEUBEN COUNTY	DANSVILLE, TOWN OF	03/09/84(M)
STEUBEN COUNTY	ERWIN, TOWN OF	07/02/1980
STEUBEN COUNTY	FREMONT, TOWN OF	10/29/1982 (M)
STEUBEN COUNTY	GREENWOOD, TOWN OF	09/03/1982 (M)
STEUBEN COUNTY	HAMMONDSPORT, VILLAGE OF	04/17/1978
STEUBEN COUNTY	HARTSVILLE, TOWN OF	09/17/1982 (M)
STEUBEN COUNTY	HORNBY, TOWN OF	04/15/1986
STEUBEN COUNTY	HORNELL, CITY OF	03/18/1980
STEUBEN COUNTY	HORNELLSVILLE, TOWN OF	07/16/1980
STEUBEN COUNTY	HOWARD, TOWN OF	09/03/1982 (M)
STEUBEN COUNTY	JASPER, TOWN OF	07/23/1982 (M)
STEUBEN COUNTY	LINDLEY, TOWN OF	08/01/1980
STEUBEN COUNTY	NORTH HORNELL, VILLAGE OF	01/17/1986
STEUBEN COUNTY	PAINTED POST, VILLAGE OF	05/18/2000
STEUBEN COUNTY	PRATTSBURG, TOWN OF	01/20/1984 (M)
STEUBEN COUNTY	PULTENEY, TOWN OF	09/30/1977
STEUBEN COUNTY	RATHBONE, TOWN OF	12/03/1982 (M)
STEUBEN COUNTY	RIVERSIDE, VILLAGE OF	05/15/1980
STEUBEN COUNTY	SAVONA, VILLAGE OF	08/15/1980
STEUBEN COUNTY	SOUTH CORNING, VILLAGE OF	10/15/1981
STEUBEN COUNTY	THURSTON, TOWN OF	02/11/1983 (M)
STEUBEN COUNTY	TROUPSBURG, TOWN OF	09/24/1982 (M)
STEUBEN COUNTY	TUSCARORA, TOWN OF	03/01/1988 (L)
STEUBEN COUNTY	URBANA, TOWN OF	01/19/1978
STEUBEN COUNTY	WAYLAND, TOWN OF	06/08/1984 (M)
STEUBEN COUNTY	WAYLAND, VILLAGE OF	08/01/1988 (L)
STEUBEN COUNTY	WAYNE, TOWN OF	11/2/1977
STEUBEN COUNTY	WEST UNION, TOWN OF	07/01/1988 (L)
STEUBEN COUNTY	WHEELER, TOWN OF	07/25/1980 (M)
STEUBEN COUNTY	WOODHULL, TOWN OF	04/02/1991
STEUBEN COUNTY/ALLEGANY COUNTY	ALMOND, TOWN OF	03/04/1980
SUFFOLK COUNTY	AMITYVILLE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	ASHAROKEN, VILLAGE OF	09/25/2009

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
SUFFOLK COUNTY	BABYLON, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	BABYLON,TOWN OF	09/25/2009
SUFFOLK COUNTY	BELLE TERRE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	BELLPORT, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	BRIGHTWATERS, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	BROOKHAVEN,TOWN OF	09/25/2009
SUFFOLK COUNTY	DERING HARBOR, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	EAST HAMPTON,TOWN OF	09/25/2009
SUFFOLK COUNTY	EAST HAMPTON,VILLAGE OF	09/25/2009
SUFFOLK COUNTY	GREENPORT, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	HEAD OF THE HARBOR, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	HUNTINGTON BAY, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	HUNTINGTON, TOWN OF	09/25/2009
SUFFOLK COUNTY	ISLANDIA, VILLAGE OF	09/25/2009 (M)
SUFFOLK COUNTY	ISLIP,TOWN OF	09/25/2009
SUFFOLK COUNTY	LAKE GROVE, VILLAGE OF	(NSFHA)
SUFFOLK COUNTY	LINDENHURST, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	LLOYD HARBOR, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	NISSEQUOGUE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	NORTH HAVEN, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	NORTHPORT, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	OCEAN BEACH, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	OLD FIELD, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	PATCHOGUE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	POQUOTT, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	PORT JEFFERSON, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	QUOGUE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	RIVERHEAD, TOWN OF	09/25/2009
SUFFOLK COUNTY	SAG HARBOR, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SAGAPONACK, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SALTAIRE,VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SHELTER ISLAND, TOWN OF	09/25/2009
SUFFOLK COUNTY	SHOREHAM, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SMITHTOWN, TOWN OF	09/25/2009
SUFFOLK COUNTY	SOUTHAMPTON, TOWN OF	09/25/2009
SUFFOLK COUNTY	SOUTHAMPTON, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SOUTHOLD,TOWN OF	09/25/2009
SUFFOLK COUNTY	THE BRANCH, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	WEST HAMPTON DUNES, VILLAGE O	09/25/2009
SUFFOLK COUNTY	WESTHAMPTON BEACH, VILLAGE OF	09/25/2009
SULLIVAN COUNTY	BETHEL, TOWN OF	02/18/2011
SULLIVAN COUNTY	BLOOMINGBURG, VILLAGE OF	02/18/2011

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
SULLIVAN COUNTY	CALLICOON, TOWN OF	02/18/2011
SULLIVAN COUNTY	COCHECTON, TOWN OF	02/18/2011
SULLIVAN COUNTY	DELAWARE, TOWN OF	02/18/2011
SULLIVAN COUNTY	FALLSBURG, TOWN OF	02/18/2011
SULLIVAN COUNTY	FORESTBURGH, TOWN OF	02/18/2011
SULLIVAN COUNTY	FREMONT, TOWN OF	02/18/2011
SULLIVAN COUNTY	HIGHLAND, TOWN OF	02/18/2011
SULLIVAN COUNTY	JEFFERSONVILLE, VILLAGE OF	02/18/2011
SULLIVAN COUNTY	LIBERTY, TOWN OF	02/18/2011
SULLIVAN COUNTY	LIBERTY, VILLAGE OF	02/18/2011
SULLIVAN COUNTY	LUMBERLAND, TOWN OF	02/18/2011
SULLIVAN COUNTY	MAMAKATING, TOWN OF	02/18/2011
SULLIVAN COUNTY	MONTICELLO, VILLAGE OF	02/18/2011
SULLIVAN COUNTY	NEVERSINK, TOWN OF	02/18/2011 (M)
SULLIVAN COUNTY	ROCKLAND, TOWN OF	02/18/2011
SULLIVAN COUNTY	THOMPSON, TOWN OF	02/18/2011
SULLIVAN COUNTY	TUSTEN, TOWN OF	02/18/2011
SULLIVAN COUNTY	WOODRIDGE, VILLAGE OF	02/18/2011 (M)
SULLIVAN COUNTY	WURTSBORO, VILLAGE OF	02/18/2011
TIOGA COUNTY	BARTON, TOWN OF	05/15/1991
TIOGA COUNTY	BERKSHIRE, TOWN OF	05/15/1985 (M)
TIOGA COUNTY	CANDOR, TOWN OF	08/19/1986
TIOGA COUNTY	CANDOR, VILLAGE OF	10/01/1991 (L)
TIOGA COUNTY	NEWARK VALLEY, TOWN OF	02/03/1982
TIOGA COUNTY	NEWARK VALLEY, VILLAGE OF	02/03/1982
TIOGA COUNTY	NICHOLS, TOWN OF	02/17/1982
TIOGA COUNTY	NICHOLS, VILLAGE OF	09/29/1986
TIOGA COUNTY	OWEGO, TOWN OF	01/17/1997
TIOGA COUNTY	OWEGO, VILLAGE OF	04/02/1982
TIOGA COUNTY	RICHFORD, TOWN OF	05/15/1985 (M)
TIOGA COUNTY	SPENCER, TOWN OF	05/15/1985 (M)
TIOGA COUNTY	SPENCER, VILLAGE OF	05/15/1985 (M)
TIOGA COUNTY	TIOGA, TOWN OF	05/17/1982
TIOGA COUNTY	WAVERLY, VILLAGE OF	03/16/1983
TOMPKINS COUNTY	CAROLINE, TOWN OF	06/19/1985 (M)
TOMPKINS COUNTY	CAYUGA HEIGHTS, VILLAGE OF	(NSFHA)
TOMPKINS COUNTY	DANBY, TOWN OF	05/15/1985 (M)
TOMPKINS COUNTY	DRYDEN, TOWN OF	05/15/1985 (M)
TOMPKINS COUNTY	DRYDEN, VILLAGE OF	01/03/1979
TOMPKINS COUNTY	FREEVILLE, VILLAGE OF	05/01/88(L)
TOMPKINS COUNTY	GROTON, TOWN OF	10/05/1984 (M)
TOMPKINS COUNTY	GROTON, VILLAGE OF	11/5/1986

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
TOMPKINS COUNTY	ITHACA, CITY OF	09/30/1981
TOMPKINS COUNTY	ITHACA, TOWN OF	06/19/1985
TOMPKINS COUNTY	LANSING, TOWN OF	10/15/1985
TOMPKINS COUNTY	LANSING, VILLAGE OF	11/19/1987
TOMPKINS COUNTY	NEWFIELD, TOWN OF	10/15/1985 (M)
TOMPKINS COUNTY	TRUMANSBURG, VILLAGE OF	04/01/1988 (L)
TOMPKINS COUNTY	ULYSSES, TOWN OF	02/19/1987
ULSTER COUNTY	DENNING, TOWN OF	05/25/1984 (M)
ULSTER COUNTY	ELLENVILLE, VILLAGE OF	09/25/2009
ULSTER COUNTY	ESOPUS, TOWN OF	09/25/2009
ULSTER COUNTY	GARDINER, TOWN OF	09/25/2009
ULSTER COUNTY	HARDENBURGH, TOWN OF	03/16/2089
ULSTER COUNTY	HURLEY, TOWN OF	08/18/2092
ULSTER COUNTY	KINGSTON, CITY OF	09/25/2009
ULSTER COUNTY	KINGSTON,TOWN OF	09/25/2009
ULSTER COUNTY	LLOYD, TOWN OF	09/25/2009
ULSTER COUNTY	MARBLETOWN, TOWN OF	09/25/2009
ULSTER COUNTY	MARLBOROUGH, TOWN OF	09/25/2009
ULSTER COUNTY	NEW PALTZ, TOWN OF	09/25/2009
ULSTER COUNTY	NEW PALTZ, VILLAGE OF	09/25/2009
ULSTER COUNTY	OLIVE, TOWN OF	11/1/1984
ULSTER COUNTY	PLATTEKILL, TOWN OF	(NSFHA)
ULSTER COUNTY	ROCHESTER, TOWN OF	09/25/2009
ULSTER COUNTY	ROSENDALE, TOWN OF	09/25/2009
ULSTER COUNTY	SAUGERTIES, TOWN OF	09/25/2009
ULSTER COUNTY	SAUGERTIES, VILLAGE OF	09/25/2009 (M)
ULSTER COUNTY	SHANDAKEN, TOWN OF	02/17/1989
ULSTER COUNTY	SHAWANGUNK, TOWN OF	09/25/2009
ULSTER COUNTY	ULSTER, TOWN OF	09/25/2009
ULSTER COUNTY	WAWARSING, TOWN OF	09/15/1983
ULSTER COUNTY	WOODSTOCK, TOWN OF	09/27/1991
WARREN COUNTY	BOLTON, TOWN OF	08/16/1996
WARREN COUNTY	CHESTER, TOWN OF	06/05/1985 (M)
WARREN COUNTY	GLENS FALLS, CITY OF	06/05/1985
WARREN COUNTY	HAGUE, TOWN OF	09/29/1996
WARREN COUNTY	HORICON, TOWN OF	02/15/1985 (M)
WARREN COUNTY	JOHNSBURG, TOWN OF	05/01/1985 (M)
WARREN COUNTY	LAKE GEORGE, TOWN OF	08/16/1996
WARREN COUNTY	LAKE GEORGE, VILLAGE OF	09/29/1996
WARREN COUNTY	LAKE LUZERNE, TOWN OF	05/01/1984
WARREN COUNTY	QUEENSBURY, TOWN OF	08/16/1996
WARREN COUNTY	STONY CREEK, TOWN OF	08/24/1984 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
WARREN COUNTY	THURMAN, TOWN OF	08/19/1986
WARREN COUNTY	WARRENSBURG, TOWN OF	03/01/1984
WASHINGTON COUNTY	ARGYLE, TOWN OF	08/24/1984 (M)
WASHINGTON COUNTY	ARGYLE, VILLAGE OF	05/18/1979 (M)
WASHINGTON COUNTY	CAMBRIDGE, TOWN OF	09/04/1985 (M)
WASHINGTON COUNTY	CAMBRIDGE, VILLAGE OF	01/02/2008
WASHINGTON COUNTY	DRESDEN, TOWN OF	09/20/1996
WASHINGTON COUNTY	EASTON, TOWN OF	11/20/1991
WASHINGTON COUNTY	FORT ANN, TOWN OF	11/5/1997
WASHINGTON COUNTY	FORT ANN, VILLAGE OF	(NSFHA)
WASHINGTON COUNTY	FORT EDWARD, TOWN OF	12/15/1982
WASHINGTON COUNTY	FORT EDWARD, VILLAGE OF	02/15/1984
WASHINGTON COUNTY	GRANVILLE, TOWN OF	08/05/1985 (M)
WASHINGTON COUNTY	GRANVILLE, VILLAGE OF	04/17/1985 (M)
WASHINGTON COUNTY	GREENWICH, VILLAGE OF	05/04/2000
WASHINGTON COUNTY	GREENWICH,TOWN OF	03/16/1992
WASHINGTON COUNTY	HAMPTON, TOWN OF	04/17/1985 (M)
WASHINGTON COUNTY	HARTFORD, TOWN OF	11/01/1985 (M)
WASHINGTON COUNTY	HEBRON, TOWN OF	06/15/1994
WASHINGTON COUNTY	HUDSON FALLS, VILLAGE OF	(NSFHA)
WASHINGTON COUNTY	JACKSON, TOWN OF	03/16/1992
WASHINGTON COUNTY	KINGSBURY, TOWN OF	09/07/1979 (M)
WASHINGTON COUNTY	PUTNAM, TOWN OF	11/20/1996
WASHINGTON COUNTY	SALEM, VILLAGE OF	04/17/1985 (M)
WASHINGTON COUNTY	SALEM,TOWN OF	04/17/1985 (M)
WASHINGTON COUNTY	WHITE CREEK, TOWN OF	04/17/1985 (M)
WASHINGTON COUNTY	WHITEHALL, TOWN OF	07/03/1986
WASHINGTON COUNTY	WHITEHALL, VILLAGE OF	06/03/1985 (M)
WAYNE COUNTY	ARCADIA, TOWN OF	11/2/1977
WAYNE COUNTY	BUTLER, TOWN OF	07/09/1982 (M)
WAYNE COUNTY	CLYDE, VILLAGE OF	12/18/1984
WAYNE COUNTY	GALEN, TOWN OF	05/16/1983
WAYNE COUNTY	HURON, TOWN OF	01/19/1996
WAYNE COUNTY	LYONS, TOWN OF	09/07/1979 (M)
WAYNE COUNTY	LYONS, VILLAGE OF	03/16/1983
WAYNE COUNTY	MACEDON, TOWN OF	01/05/1984
WAYNE COUNTY	MACEDON, VILLAGE OF	09/30/1983
WAYNE COUNTY	MARION, TOWN OF	07/01/1988 (L)
WAYNE COUNTY	NEWARK, VILLAGE OF	07/15/1988
WAYNE COUNTY	ONTARIO, TOWN OF	06/01/1978
WAYNE COUNTY	PALMYRA, TOWN OF	03/01/1978
WAYNE COUNTY	PALMYRA, VILLAGE OF	07/15/1988

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
WAYNE COUNTY	RED CREEK, VILLAGE OF	04/08/1983 (M)
WAYNE COUNTY	ROSE, TOWN OF	03/09/1984 (M)
WAYNE COUNTY	SAVANNAH, TOWN OF	08/06/1982 (M)
WAYNE COUNTY	SODUS POINT, VILLAGE OF	11/2/1977
WAYNE COUNTY	SODUS, TOWN OF	06/02/1992
WAYNE COUNTY	WALWORTH, TOWN OF	03/16/1983
WAYNE COUNTY	WILLIAMSON TOWN	10/17/1978
WAYNE COUNTY	WOLCOTT, TOWN OF	06/02/1992
WAYNE COUNTY	WOLCOTT, VILLAGE OF	07/06/1984 (M)
WESTCHESTER COUNTY	ARDSLEY, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	BEDFORD, TOWN OF	09/28/2007
WESTCHESTER COUNTY	BRIARCLIFF MANOR, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	BRONXVILLE, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	BUCHANAN, VILLAGE OF	09/28/2007 (M)
WESTCHESTER COUNTY	CORTLANDT, TOWN OF	09/28/2007
WESTCHESTER COUNTY	CROTON-ON-HUDSON, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	DOBBS FERRY, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	EASTCHESTER, TOWN OF	09/28/2007
WESTCHESTER COUNTY	ELMSFORD, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	GREENBURGH,TOWN OF	09/28/2007
WESTCHESTER COUNTY	HARRISON, TOWN OF	09/28/2007
WESTCHESTER COUNTY	HASTINGS-ON-HUDSON, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	IRVINGTON, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	LARCHMONT, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	LEWISBORO, TOWN OF	09/28/2007 (M)
WESTCHESTER COUNTY	MAMARONECK, TOWN OF	09/28/2007
WESTCHESTER COUNTY	MAMARONECK, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	MOUNT KISCO, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	MOUNT PLEASANT, TOWN OF	09/28/2007
WESTCHESTER COUNTY	MOUNT VERNON, CITY OF	09/28/2007
WESTCHESTER COUNTY	NEW CASTLE, TOWN OF	09/28/2007
WESTCHESTER COUNTY	NEW ROCHELLE, CITY OF	09/28/2007
WESTCHESTER COUNTY	NORTH CASTLE, TOWN OF	09/28/2007
WESTCHESTER COUNTY	NORTH SALEM, TOWN OF	09/28/2007
WESTCHESTER COUNTY	OSSINING, TOWN OF	09/28/2007
WESTCHESTER COUNTY	OSSINING, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	PEEKSKILL, CITY OF	09/28/2007
WESTCHESTER COUNTY	PELHAM MANOR, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	PELHAM, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	PLEASANTVILLE, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	PORT CHESTER, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	POUND RIDGE, TOWN OF	09/28/2007

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
WESTCHESTER COUNTY	RYE BROOK, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	RYE, CITY OF	09/28/2007
WESTCHESTER COUNTY	SCARSDALE, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	SLEEPY HOLLOW, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	SOMERS, TOWN OF	09/28/2007
WESTCHESTER COUNTY	TARRYTOWN, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	TUCKAHOE, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	WHITE PLAINS, CITY OF	09/28/2007
WESTCHESTER COUNTY	YONKERS, CITY OF	09/28/2007
WESTCHESTER COUNTY	YORKTOWN, TOWN OF	09/28/2007
WYOMING COUNTY	ARCADE, TOWN OF	03/03/1992
WYOMING COUNTY	ARCADE, VILLAGE OF	03/03/1992
WYOMING COUNTY	ATTICA, TOWN OF	04/30/1986
WYOMING COUNTY	BENNINGTON, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	CASTILE, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	CASTILE, VILLAGE OF	05/28/1982 (M)
WYOMING COUNTY	COVINGTON, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	EAGLE, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	GAINESVILLE, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	GAINESVILLE, VILLAGE OF	02/15/1985 (M)
WYOMING COUNTY	GENESEE FALLS, TOWN OF	05/01/1984
WYOMING COUNTY	JAVA, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	ORANGEVILLE, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	PERRY, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	PERRY, VILLAGE OF	07/29/1977 (M)
WYOMING COUNTY	PIKE, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	PIKE, VILLAGE OF	06/18/1982 (M)
WYOMING COUNTY	SHELDON, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	SILVER SPRINGS, VILLAGE OF	01/20/1984 (M)
WYOMING COUNTY	WARSAW, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	WARSAW, VILLAGE OF	11/18/1981
WYOMING COUNTY	WETHERSFIELD, TOWN OF	07/16/1982
WYOMING COUNTY	WYOMING, VILLAGE OF	08/03/1981
YATES COUNTY	BARRINGTON, TOWN OF	03/09/1984 (M)
YATES COUNTY	BENTON, TOWN OF	01/20/1984 (M)
YATES COUNTY	DRESDEN, VILLAGE OF	06/15/1981
YATES COUNTY	DUNDEE, VILLAGE OF	03/01/1988 (L)
YATES COUNTY	ITALY, TOWN OF	03/07/2001
YATES COUNTY	JERUSALEM, TOWN OF	01/20/1984 (M)
YATES COUNTY	MIDDLESEX, TOWN OF	09/29/1989
YATES COUNTY	MILO, TOWN OF	07/18/1985 (M)
YATES COUNTY	PENN YAN, VILLAGE OF	06/15/1981

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
YATES COUNTY	POTTER, TOWN OF	03/23/1984 (M)
YATES COUNTY	RUSHVILLE, VILLAGE OF	06/05/1985 (M)
YATES COUNTY	STARKEY, TOWN OF	12/3/1987
YATES COUNTY	TORREY, TOWN OF	12/3/1987

Notes:
(NSFHA) - No special flood hazard area - All Zone "C"
(M) No elevation determined - All Zone "A", "C", and "X"
(L) Original FIRM by letter - All Zone "A", "C", and "X"
(S) Suspended community, not in the National Flood Program.
(X) Community not in National Flood Program
(>) Date of current effective map is after the date of this report.
Source: FEMA "Community Status Book Report – June 29, 2011."
(http://www.fema.gov/fema/csb.shtm)

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New York State

DEC

Appendix 2

1992 SEQRA Findings Statement on the GEIS on the Oil, Gas and Solution Mining Regulatory Program

Revised Draft
Supplemental Generic Environmental Impact Statement

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September 1, 1992

Findings Statement

Pursuant to the State Environmental Quality Review Act (SEQR) of the Environmental Conservation Law (ECL) and the SEQR Regulations 6NYCRR Part 617, the New York State Department of Environmental Conservation makes the following findings.

Name of Action

Adoption of the Final Generic Environmental Impact Statement (GEIS) on the Oil, Gas and Solution Mining Regulatory Program.

Description and Background

In early 1988, the Department of Environmental Conservation released the Draft GEIS on the Oil, Gas and Solution Mining Regulatory Program. The Draft GEIS comprehensively reviewed the environmental impacts of the Department's program for regulating the siting, drilling, production and plugging and abandonment of oil, gas, underground gas storage, solution mining, brine disposal, geothermal and stratigraphic test wells. Six public hearings were held on the Draft GEIS in June 1988.

The Final GEIS was released in July 1992. It contains individual responses to the hundreds of comments received on the Draft GEIS. The Final GEIS also includes more detailed topical responses addressing several controversial issues that frequently appeared in the comments on the draft document.

Together, the Draft and Final GEIS and this Findings Statement will provide the groundwork for revisions to the Oil, Gas and Solution Mining Regulations (6NYCRR Parts 550-559). These regulations are being updated to more accurately reflect and effectively implement the current Oil, Gas and Solution Mining Law (ECL Article 23).

The Draft GEIS included suggested changes to the regulations in bold print throughout the document. In the interests of environmental protection and public safety, a significant

number of the suggested regulatory changes are already put in effect as standard conditions routinely applied to permits. All formal regulation changes, however, must be promulgated in accordance with the State Administrative Procedure Act (SAPA) requiring separate review, public hearings and approval. Further public input during the rulemaking process may cause some of the new regulations, when they are eventually adopted, to differ from those discussed in the GEIS. Any regulations adopted that differ significantly from those discussed in the GEIS will undergo an additional SEQR Review and Determination.

Location

Statewide.

DEC Jurisdiction

Jurisdiction is provided by the Oil, Gas and Solution Mining Law (ECL Article 23).

Date Final GEIS Filed

The Final GEIS was filed June 25, 1992/#PO-009900-00046. The Notice of Completion was published in the Environmental Notice Bulletin July 8, 1992.

Facts and Conclusions Relied Upon to Support the SEQR Findings

The record of facts established in the Draft and Final GEIS upholds the following conclusions:

1. The **unregulated** siting, drilling, production, and plugging and abandonment of oil, gas, solution mining, underground gas storage, brine disposal, geothermal and stratigraphic test wells could have potential negative impacts on every aspect of the environment. The potential negative impacts range from very minor to significant. Potential impacts of **unregulated** activities on ground and surface waters are a particularly serious concern. The potential negative impacts on all environmental resources are described in detail in Chapters 8 through 14 and summarized in Chapter 16 of the Draft GEIS.

2. Under **existing regulations and permit conditions**, the potential environmental impacts of the above wells are **greatly reduced** and most are reduced to non-significant levels. The extensive mitigation measures required under the existing regulatory program are described in detail in Chapters 8 through 14 and summarized in Chapter 17 of the Draft GEIS.

3. The potential environmental impacts associated with the activities covered by the Oil, Gas and Solution Mining Regulatory Program also have economic and social implications. For example, it is less expensive to prevent pollution than pay for remediation of environmental problems, health care costs, and lawsuit expenses. The State also receives significant economic benefits from the activities covered by the regulatory program. The regulated industries provide jobs and economic stimulus through the purchase of goods and services, and the payment of taxes, royalties and leasing bonuses. Additional information on the potential economic impacts associated with the activities covered by the regulatory program is provided in Chapter 18 of the Draft GEIS.

4. The Department's routine requirement of: 1) a program-specific Environmental Assessment Form (EAF) with <u>every</u> well drilling permit application, 2) a plat (map) showing the proposed well location, and 3) a pre-drilling site inspection, allows the Department to:

   - reliably determine potential environmental problems, and
   - select appropriate permit conditions for mitigating potential environmental impacts.

   The EAF is printed in its entirety and discussed in detail on pages FGEIS 30-34 of the Final GEIS. Information on the permit application review process is summarized in Chapter 7 of the Draft GEIS.

5. The majority of the industry's activity centers on drilling individual oil and gas wells for primary production. For purposes of this Findings Statement, standard oil and gas operations are defined as:

- any procedure relevant to rotary or cable tool drilling procedures, and
- production operations which do not utilize any type of artificial means to facilitate the recovery of hydrocarbons.

The basic features of standard oil and gas operations are described in detail in Chapters 9 through 11 of the Draft GEIS.

6. The diverse types of wells covered by the regulatory program have enough design and operational characteristics in common to group them according to their potential environmental impacts. Design and operational aspects of these wells are described in detail in Chapters 9 through 14 of the Draft GEIS.

7. The magnitude of potential environmental impacts associated with any proposed well covered by the regulatory program is strongly influenced by the types of natural and cultural resources in the well's vicinity. New York State's environmental resources are described in Chapter 6 of the Draft GEIS. Most of the information on the potential environmental impacts of the regulated activities on these environmental resources can be found in Chapter 8 of the Draft GEIS, which deals with siting issues. Additional information on potential impacts related to specific stages (drilling, completion, production, plugging and abandonment) of well operation can be found in Chapters 9 through 11 of the Draft GEIS. Additional information on potential environmental impacts related specifically to enhanced oil recovery, solution salt mining, underground gas storage and waste brine disposal can be found in Chapters 12 through 15 of the Draft GEIS.

8. The range of future alternatives concerning the activities covered by the Oil, Gas and Solution Mining Regulatory Program can be divided into three basic categories: 1) prohibition on regulated activities, 2) removal of regulation, and 3) maintenance of status quo versus revision of existing regulations. A prohibition on these regulated activities would deprive the State of substantial economic and natural resource benefits. Complete removal of regulation would lead to severe environmental problems. While the existing regulations and permit conditions provide significant environmental protection, there is still room to improve the efficiency and effectiveness of the program. Revision of the existing regulations is the best alternative. Chapter 21 of the Draft GEIS contains a more detailed assessment of the environmental, economic, and social aspects of each alternative.

SEQR Determinations of Significance

The SEQR determinations on the significance of the environmental impacts associated with the activities covered by this regulatory program are presented in the following table. The determinations are supported by the conclusions listed above, which in turn are supported by the referenced sections of the Draft and Final GEIS.

SEQR DETERMINATIONS

Agency Action	Environmental Impact	Explanation
a. Standard individual oil, gas, solution mining, stratigraphic, geothermal, or gas storage well drilling permits (no other permits involved).	not significant	Rules and regulations and conditions are adequate to protect the environment. The Draft and Final GEIS satisfy SEQR for these actions. A site-specific EAF is required with the permit application.
b. Oil and gas drilling permits in State Parklands.	may be significant	Site-specific conditions of State Parklands are not discussed in the Draft and Final GEIS. Further determination of significant environmental impacts is needed for State Parklands. A site-specific EAF is required with the permit application.
c. Oil and gas drilling permits in Agricultural Districts.	may be significant	Rules and regulations and conditions are adequate to protect the environment. For most oil and gas operations in Agricultural Districts which utilize less than 2½ acres the GEIS satisfies SEQR. If more than 2½ acres are disturbed, this is a Type I action under 6NYCRR Part 617 and an additional determination of significance is required. A site-specific EAF is required with the permit application.
d. Oil and gas drilling permits in the "Bass Island" fields.	not significant	Special conditions and regulations under Part 559 are adequate to protect the environment. The Draft and Final GEIS satisfy SEQR for these actions. A site-specific EAF is required with the permit application.

e. Oil and gas drilling permits for locations above aquifers.	not significant	Rules and regulations and special aquifer conditions employed by DEC have been developed specifically to protect the groundwater resources of the State. The Draft and Final GEIS satisfy SEQR for these actions. A site-specific EAF is required with the permit application.
f. Oil and gas drilling permits in close proximity (less than 1,000 feet) to municipal water supply wells.	always significant	A supplemental EIS is required dealing with the groundwater hydrology, potential impacts and mitigation measures. A site-specific EAF is required with the permit application.
g. Oil and gas drilling permits in proximity (between 1,000 and 2,000 feet) to municipal water supply wells.	may be significant	A supplemental EIS may be required dealing with the groundwater hydrology, potential impacts and mitigation measures. A site-specific assessment and SEQR determination are required. A site-specific EAF is required with the permit application.
h. Oil and gas drilling permits when other DEC permits required.	may be significant	A site-specific SEQR assessment and determination are needed based on the environmental conditions requiring additional DEC permits. A site-specific EAF is required with the permit application.
i. Plugging permits for oil, gas, solution mining, stratigraphic, geothermal, gas storage and brine disposal wells.	Type II *	By law all wells drilled must be plugged before abandonment. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action.

* Under 6NYCRR 617.13, a Type II action is one which has been determined not to have a significant effect on the environment and does not require any other SEQR determination or procedure.

j. New waterflood or tertiary recovery projects.	may be significant	For major new waterfloods and new tertiary recovery projects, a site specific environmental assessment and SEQR determination are required. A supplemental EIS may be required for new waterfloods to ensure integrity of the flood. Also, a supplemental EIS may be required for new tertiary recovery projects depending on the scope of operations and methods used. A site-specific EAF is required with the permit application.
k. New underground gas storage projects or major modifications.	may be significant	A site-specific environmental assessment and SEQR determination are required. May require a supplemental EIS depending on the scope of the project. A site-specific EAF is required with the permit application.
l. New solution mining projects or major modifications.	may be significant	A site-specific environmental assessment and SEQR determination are required. May require a supplemental EIS depending on the scope of the project. A site-specific EAF is required with the permit application.
m. Spacing hearing.	not significant	Action to hold hearing is non-significant. A review and SEQR determination with respect to all other issues must be made before the hearing. Any permit issued subsequently will be reviewed on issues raised at hearing. A site-specific EAF is required with the permit application.
n. Variance hearing.	not significant	Action to hold hearing is non-significant. A review and SEQR determination with respect to all other issues must be made before the hearing. Any permit issued subsequently will be reviewed on issues raised at hearing. A site-specific EAF is required with the permit application.

o. Compulsory unitization hearing.	not significant	Action to hold hearing is non-significant. A review and SEQR determination with respect to all other issues must be made before the hearing. Any permit issued subsequently will be reviewed on issues raised at hearing. A site-specific EAF is required with the permit application.
p. Natural Gas Policy Act pricing recommendations.	none	Action only results in recommendations to Federal Energy Regulatory Commission; therefore, action is not subject to SEQR.
q. Brine disposal well drilling or conversion permit.	may be significant	The brine disposal well permitting guidelines require an extensive surface and subsurface evaluation which is in effect a supplemental EIS addressing technical issues. An additional site specific environmental assessment and SEQR determination are required. A site-specific EAF is required with the permit application.

SEQR Review Procedures

Upon filing of this Findings Statement, the following SEQR Review procedures will be adopted for the Oil, Gas and Solution Mining Regulatory Program:

1. A shortened program-specific Environmental Assessment Form (EAF) will continue to be required with every well drilling permit application, regardless of the SEQR determination listed in the previous table. Information required by the EAF is considered to be an essential part of the permit application. It contains vital site-specific information necessary to evaluate the need for individual permit conditions.

2. In the following cases where the GEIS satisfies SEQR, Department staff will no longer make Determinations of Significance and a Negative or Positive Declaration under SEQR will no longer be required so long as projects conform to the descriptions in the Draft and Final GEIS:

   - Standard individual oil, gas, solution mining, stratigraphic test, geothermal or gas storage well drilling permits,
   - Oil and gas drilling permits in the "Bass Islands" field, and
   - Oil and gas drilling permits for locations above aquifers.

3. In addition to the short program-specific EAF, permits for the following projects will also require detailed site-specific environmental assessments using the Long-Form EAF published in Appendix A of 6NYCRR Part 617. A site or project-specific EIS may also be required for the following projects depending upon the information revealed in the permit application and accompanying EAF's:

   - Oil and gas drilling permits in Agricultural Districts if more than two and one-half acres will be altered by construction of the well site and access road.
   - Oil and gas drilling permits in State Parklands.
   - Oil and gas drilling permits when other DEC permits are required.

- Oil and gas drilling permits less than 2,000 feet from a municipal water supply well.
- New major waterflood or tertiary recovery projects.
- New underground gas storage projects or major modifications.
- New solution mining projects or major modifications.
- Brine disposal well drilling or conversion permits.
- Any other project not conforming to the standards, criteria or thresholds required by the Draft and Final GEIS.

Other SEQR Considerations

In conducting SEQR reviews, the Department will handle the topics of individual project scope, project size, lead agency, and coastal resources as described below.

1. Project scope - Each application to drill a well will continue to be considered as an individual project. An applicant applying for five wells will continue to be treated the same as five applicants applying to the Department individually, since the wells may not be drilled at the same time or in the same area. Planned future wells might not be drilled at all depending on the results of the first well drilled.

   The exceptions to this are proposed new or major expansions of solution mining, enhanced recovery or underground gas storage operations which require that several wells be drilled and operated for an extended period of time within a limited area.

2. Size of Project - The size of the project will continue to be defined as the surface acreage affected by development.

3. Lead Agency - In 1981, the Legislature gave exclusive authority to the Department to regulate the oil, gas and solution mining industries under ECL Section 23-0303(2). Thus, only the Department has jurisdiction to grant drilling permits for wells subject to Article 23, except within State parklands. To the extent practicable, the Department will actively seek lead agency designation consistent

with the general intent of Chapter 846 of the Laws of 1981.

4. Coastal Resources - On the program specific EAF that must accompany every drilling permit application, the applicant must indicate whether the proposed well is in a legally designated New York State Coastal Zone Management (CZM) Area. Neither the policies in the New York State CZM Plan, nor the provisions of individual Local Waterfront Revitalization Plans (LWRP's) are covered in the GEIS. Once an LWRP is adopted by a community, it is a legally binding part of the New York State CZM Plan. The Department cannot issue any drilling permit unless it is consistent with the New York State CZM Plan to the "maximum extent practicable."

CERTIFICATION OF FINDINGS TO ADOPT THE FINAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM

Having considered the Draft and Final GEIS, and having considered the preceding written facts and conclusions relied upon to meet the requirements of 6NYCRR Part 617.9, this Statement of Findings certifies that:

1. The requirements of 6NYCRR Part 617 have been met;

2. Consistent with the social, economic and other essential considerations from among the reasonable alternatives thereto, the action approved is one which minimizes or avoids adverse environmental effects to the maximum extent practicable; including the effects disclosed in the environmental impact statement, and

3. Consistent with social, economic and other essential considerations, to the maximum extent practicable, adverse environmental effects revealed in the environmental impact statement process will be minimized or avoided by incorporating as conditions to the decision those mitigative measures which were identified as practicable.

4. Consistent with the applicable policies of Article 42 of the Executive Law, as implemented by 19 NYCRR 600.5, this action will achieve a balance between the protection of the environment and the need to accommodate social and economic considerations.

Director
Division of Mineral Resources

Sept. 29, 1992
Date

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New York State

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Appendix 3

Supplemental SEQRA Findings Statement on Leasing of State Lands for Activities Regulated Under the Oil, Gas and Solution Mining Law

Revised Draft
Supplemental Generic Environmental Impact Statement

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SEQR File No.

P0-009900-00046

Supplemental
Findings Statement

Pursuant to the State Environmental Quality Review Act (SEQR) of the Environmental Conservation Law (ECL) and the SEQR Regulations 6NYCRR Part 617, the New York State Department of Environmental Conservation makes the following supplemental findings on the Final Generic Environmental Impact Statement (GEIS) on the Oil, Gas and Solution Mining Regulatory Program.

Name of Action

Adoption of supplemental findings on leasing of state lands for activities regulated under the Oil, Gas and Solution Mining Law (ECL Article 23).

Description and Background

In early 1988, the Department of Environmental Conservation released the Draft GEIS on the Oil, Gas and Solution Mining Regulatory Program. The Draft GEIS comprehensively reviewed the environmental impacts of the Department's program for regulating the siting, drilling, production and plugging and abandonment of oil, gas, underground gas storage, solution mining, brine disposal, geothermal and stratigraphic test wells. The findings statement issued on the Draft and Final GEIS in September, 1992 neglected to specifically mention DEC's program for leasing of State lands for these resource development activities.

Prior to adoption of the GEIS, proposed lease sales underwent a segmented review. Segmented reviews are permitted under certain circumstances if they are no less protective of the environment. This is true given the highly speculative nature of oil and gas leasing practices:

- It is impractical to review the potential environmental impacts of development activities at the leasing stage. Information on the placement of well sites is not generally known, even by the lessee. Not until a company successfully obtains a lease does it invest time and money in preparing the exploration and development plans that will be submitted to the Department for approval if the lessee wishes to commence operations.

- Most of the land leased will never be directly affected by development activities. Based on a 15 year record of the State's leasing program, less than one percent of all the State land leased has been subject to any direct impact.

- When the lessee does decide on a proposed well site on a State lease, the lessee must obtain a site-specific drilling permit from the Department. With eve well drilling permit application the Department requires: 1) a program-specific Environmental Assessment Form, 2) a plat (map) showing the proposed well location and support facilities, and 3) a pre-drilling site inspection that allows the Department to :
  - reliably determine potential environmental problems; and

- select appropriate permit conditions for mitigating potential environmental impacts.

- Possession of a lease does not a priori grant the right to drill on a lease. Nor is the lessee in any way guaranteed approval for their first-choice drilling location. Clauses included in the lease inform the lessee that any surface disturbing activities must receive Department review and approval prior. to their commencement. Leases also contain clauses recommended by other State agency staff that are necessary for protection of fish, wildlife, plant, land, air, wetlands, water and cultural resources on the leased parcels.

SEOR Determination of Significance

The Department has determined that the act of leasing State lands for activities regulated under ECL Article 23 does not have a significant environmental impact. This determination is supported by the facts listed above.

SEOR Review Procedures

Department staff will no longer make Determinations of Significance and Negative or Positive Declarations under SEQR for leases on State lands for activities regulated under ECL Article 23 at the time that the lease is granted; SEQR reviews will continue to be done as needed for site-specific development.

CERTIFICATION OF SUPPLEMENTAL FINDINGS ON THE FINAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM

Having considered the Draft and Final GEIS, and having considered the preceding written facts and conclusions relied upon to meet the requirements of 6NYCRR Part 617.9, this Supplemental Statement of Findings certifies that:

1. The requirements of 6NYCRR Part 617 have been met.

2. Consistent with the social, economic, and other essential considerations from among the reasonable alternatives thereto, the action approved is one which minimizes or avoids adverse environmental effects to the maximum extent practicable; including the effects disclosed in the environmental impact statement.

3. Consistent with the social, economic, and other essential considerations, to the maximum extent practicable, adverse environmental effects revealed in the environmental impact statement process will be minimized or avoided by incorporating as conditions to the decision those mitigative measures which were identified as practicable.

4. Consistent with the applicable policies of Article 42 of the Executive Law, as implemented by 19 NYCRR 600.5, this action will achieve a balance between the protection of the environment and the need to accommodate social and economic considerations.

/S/ April 19, 1993

Gregory H. Sovas, Director
Division of Mineral Resources

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New York State

DEC

Appendix 4

Application Form for Permit to Drill, Deepen, Plug Back or Convert A Well Subject to the Oil, Gas and Solution Mining Regulatory Program

Revised Draft
Supplemental Generic Environmental Impact Statement

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NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF MINERAL RESOURCES

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APPLICATION FOR PERMIT TO DRILL, DEEPEN, PLUG BACK OR CONVERT A WELL SUBJECT TO THE OIL, GAS AND SOLUTION MINING LAW

THIS APPLICATION IS A LEGAL DOCUMENT. READ THE APPLICABLE AFFIRMATION AND ACKNOWLEDGMENT CAREFULLY BEFORE SIGNING.
For instructions on completing this form, visit the Division's website at www.dec.ny.gov/energy/205.html or contact your local Regional office.

PLANNED OPERATION: (Check one)
☐ Drill ☐ Deepen ☐ Plug Back ☐ Convert

TYPE OF WELL: (Check one)
☐ New ☐ Existing

Existing API Well Identification Number
31- | | | - | | | | | - | | - | | |

TYPE OF WELL BORE: (Check one)
☐ Vertical ☐ Directional ☐ Horizontal

NAME OF OWNER (Full Name of Organization or Individual as registered with the Division)	TELEPHONE NUMBER (include area code)
ADDRESS (P.O. Box or Street Address, City, State, Zip Code)	
NAME AND TITLE OF LOCAL REPRESENTATIVE WHO CAN BE CONTACTED WHILE OPERATIONS ARE IN PROGRESS	
ADDRESS–Business (P.O. Box or Street Address, City, State, Zip Code)	TELEPHONE NUMBER (include area code)
ADDRESS–Night, Weekend and Holiday (P.O. Box or Street Address, City, State, Zip Code)	TELEPHONE NUMBER (include area code)

WELL LOCATION DATA (attach plat)

COUNTY	TOWN	FIELD/POOL NAME (or "Wildcat")
WELL NAME	WELL NUMBER	NUMBER OF ACRES IN UNIT
7½ MINUTE QUAD NAME	QUAD SECTION	PROPOSED TARGET FORMATION

LOCATION DESCRIPTION

			Decimal Latitude (NAD83)	Decimal Longitude (NAD83)
Surface	0'	0	☐☐.☐☐☐☐☐☐	☐☐.☐☐☐☐☐☐
Top of Target Interval			☐☐.☐☐☐☐☐☐	☐☐.☐☐☐☐☐☐
Bottom of Target Interval			☐☐.☐☐☐☐☐☐	☐☐.☐☐☐☐☐☐
Bottom Hole	TVD	TMD	☐☐.☐☐☐☐☐☐	☐☐.☐☐☐☐☐☐

PROPOSED WELL DATA

WELL TYPE (check one)
☐ Oil Production ☐ Gas Production ☐ Brine ☐ Storage
☐ Injection ☐ Brine Disposal ☐ Geothermal ☐ Stratigraphic
☐ Other _____

PLANNED TOTAL DEPTH
TVD _____ ft.
TMD _____ ft.
Kickoff _____ TMD

PLANNED DATE OF COMMENCEMENT OF OPERATIONS

SURFACE ELEVATION (check how obtained)
_____ ft. ☐ Surveyed ☐ Topo Map ☐ Other _____

TYPE TOOLS
☐ Cable ☐ Rotary

PLANNED DRILLING FLUID
☐ Air ☐ Water ☐ Mud

NAME OF PLANNED DRILLING CONTRACTOR (as registered with the Division)	TELEPHONE NUMBER (include area code)

ON ATTACHED SHEET GIVE DETAILS FOR EACH PROPOSED CASING STRING AND CEMENT JOB INCLUDING BUT NOT LIMITED TO: Bit size, casing size, casing weight and grade, TVD and TMD of casing set, scratchers, centralizers, cement baskets, sacks of cement, class of cement, cement additives with percentages or pounds per sack, estimated TVD and TMD of the top of cement, estimated amount of excess cement and waiting-on-cement time.

FOR DIRECTIONAL OR SIDETRACK WELLS ALSO INCLUDE A WELL BORE DIAGRAM SHOWING THE LOCATION OF THE ITEMS INCLUDED IN THE ABOVE REFERENCED DETAILS.

DEPARTMENT USE ONLY

BOND NUMBER	
API WELL IDENTIFICATION NUMBER 31-	
RECEIPT NUMBER	
DATE ISSUED	

APPLICATION FOR PERMIT TO DRILL, DEEPEN, PLUG BACK OR CONVERT

WELL NAME	WELL NUMBER	NAME OF OWNER

COMMENTS:

AFFIRMATION AND ACKNOWLEDGMENT

A. For use by individual:

By the act of signing this application:

(1) I affirm under penalty that the information provided in this application is true to the best of my knowledge and belief; and that I possess the right to access property, and drill and/or extract oil, gas, or salt, by deed or lease, from the lands and site described in the well location data section of this application. I am aware that any false statement made in this application is punishable as a Class A Misdemeanor under Section 210.45 of the Penal Law.

(2) I acknowledge that if the permit requested to be issued in consideration of the information and affirmations contained in this application is issued, as a condition to the issuance of that permit, I accept full legal responsibility for all damage, direct or indirect, of whatever nature and by whomever suffered, arising out of the activity conducted under authority of that permit; and agree to indemnify and hold harmless the State, its representatives, employees, agents, and assigns for all claims, suits, actions, damages, and costs of every name and description, arising out of or resulting from the permittee's undertaking of activities or operation and maintenance of the facility or facilities authorized by the permit in compliance or non-compliance with the terms and conditions of the permit.

_____
Printed or Typed Name of Individual

_____ _____
Signature of Individual Date

B. For use by organizations other than an individual:

By the act of signing this application:

(1) I affirm under penalty of perjury that I am _____ (title) of _____ (organization); that I am authorized by that organization to make this application; that this application was prepared by me or under my supervision and direction; and that the aforenamed organization possesses the right to access property, and drill and/or extract oil, gas, or salt by deed or lease, from the lands and site described in the well location data section of this application. I am aware that any false statement made in this application is punishable as a Class A Misdemeanor under Section 210.45 of the Penal Law.

(2) _____ (organization); acknowledges that if the permit requested to be issued in consideration of the information and affirmations contained in this application is issued, as a condition to the issuance of that permit, it accepts full legal responsibility for all damage, direct or indirect, of whatever nature and by whomever suffered, arising out of the activity conducted under authority of that permit; and agrees to indemnify and hold harmless the State, its representatives, employees, agents, and assigns for all claims, from suits, actions, damages, and costs of every name and description, arising out of or resulting from the permittee's undertaking of activities or operation and maintenance of the facility or facilities authorized by the permit in compliance or non-compliance with the terms and conditions of the permit.

_____
Printed or Typed Name of Authorized Representative

_____ _____
Signature of Authorized Representative Date

New York State

DEC

Appendix 5

Environmental Assessment Form (EAF) For Well Permitting

Revised Draft
Supplemental Generic Environmental Impact Statement

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85-16-5 (1/07)--10b

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF MINERAL RESOURCES

ENVIRONMENTAL ASSESSMENT FORM

Attachment to Drilling Permit Application

WELL NAME AND NUMBER

NAME OF APPLICANT	BUSINESS TELEPHONE NUMBER ( )

ADDRESS OF APPLICANT

CITY/P.O.	STATE	ZIP CODE

DESCRIPTION OF PROJECT (Briefly describe type of project or action)

PROJECT SITE IS THE WELL SITE AND SURROUNDING AREA WHICH WILL BE DISTURBED DURING CONSTRUCTION OF SITE, ACCESS ROAD, and PIT AND ACTIVITIES DURING DRILLING AND COMPLETION AT WELLHEAD.

(PLEASE COMPLETE EACH QUESTION--Indicate N.A., if not applicable)

LAND USE AND PROJECT SITE

1. Project Dimensions. Total Area of Project Site _____ sq. ft.
   Approximate square footage for items below:

		During Construction (sq. ft.)	After Construction (sq. ft.)
a. Access Road	(length x width)		
b. Well Site	(length x width)		

2. Characterize Project Site Vegetation and Estimate Percentage of Each Type Before Construction:

   _____ % Agricultural (cropland, hayland, pasture, vineyard, etc.) _____ % Forested _____ % Wetlands

   _____ % Meadow or Brushland (non agricultural) _____ % Non vegetated (rock, soil, fill)

3. Present Land Use(s) Within ¼ Mile of Project (Check all that apply)

   ☐ Rural ☐ Suburban ☐ Forest ☐ Urban ☐ Agricultural ☐ Commercial ☐ Park/Recreation
   ☐ Industrial ☐ Other _____

4. How close is the nearest residence, building, or outdoor facility of any type routinely occupied by people at least part of the day? _____ ft.

   Describe _____

ENVIRONMENTAL RESOURCES ON/NEAR PROJECT SITE

5. The presence of certain environmental resources on or near the project site may require additional permits, approvals or mitigation measures--Is any part of the well site or access road located:

a. Over a primary or principal aquifer?	☐ Yes	☐ No	☐ Not Known
b. Within 2,640 feet of a public water supply well?	☐ Yes	☐ No	☐ Not Known
c. Within 150 feet of a surface municipal water supply?	☐ Yes	☐ No	☐ Not Known
d. Within 150 feet of a lake, stream, or other public surface water body?	☐ Yes	☐ No	☐ Not Known
e. Within an Agricultural District?	☐ Yes	☐ No	☐ Not Known
f. Within a land parcel having a Soil and Water Conservation Plan?	☐ Yes	☐ No	☐ Not Known
g. In a 100 year flood plain?	☐ Yes	☐ No	☐ Not Known
h. In a regulated wetland or its 100 foot buffer zone?	☐ Yes	☐ No	☐ Not Known
i. In a coastal zone management area?	☐ Yes	☐ No	☐ Not Known
j. In a Critical Environmental Area?	☐ Yes	☐ No	☐ Not Known
k. Does the project site contain any species of animal life that are listed as threatened or endangered?	☐ Yes	☐ No	☐ Not Known
If yes, identify the species and source of information _____			
l. Will proposed project significantly impact visual resources of statewide significance?	☐ Yes	☐ No	☐ Not Known
If yes, identify the visual resource and source of information _____			

CULTURAL RESOURCES

6. Are there any known archeological and/or historical resources which will be affected by drilling operations? ☐ Yes ☐ No ☐ Not Known

7. Has the land within the project area been previously disturbed or altered (excavated, landscaped, filled, utilities installed)? ☐ Yes ☐ No ☐ Not Known

If answer to Number 6 or 7 is yes, briefly descrbe _____

EROSION AND RECLAMATION PLANS

8. Indicate percentage of project site within: 0-10% slope _____ % 10-15% slope _____ % greater than 15% slope _____ %

9. Are erosion control measures needed during construction of the access road and well site? ☐ Yes ☐ No ☐ Not Known

If yes, describe and/or sketch on attached photocopy of plat _____

10. Will the topsoil which is disturbed be stockpiled for reclamation use? ☐ Yes ☐ No

11. Does the reclamation plan include revegetation? ☐ Yes ☐ No

If yes, what plant materials will be used? _____

12. Does the reclamation plan include restoration or installation of surface or subsurface drainage features to prevent erosion or conform to a Soil and Water Conservation Plan? ☐ Yes ☐ No

If yes, describe _____

ACCESS ROAD SITING AND CONSTRUCTION

13. Are you going to use existing or common corridors when building the access road? ☐ Yes ☐ No
Locate access road on attached photocopy of plat.

DRILLING

14. Anticipated length of drilling operations? _____ days.

WASTE STORAGE AND DISPOSAL

15. How will drilling fluids and stimulation fluids:

a. Be contained? _____

b. Be disposed of? _____

16. Will production brine be stored on site? ☐ Yes ☐ No

If yes:
How will it be stored? _____

How will it be disposed of? _____

17. Will the drill cuttings and pit liner be disposed of on site? ☐ Yes ☐ No

If yes, expected burial depth? _____ feet

ADDITIONAL PERMITS

18. Are any additional State, Local or Federal permits or approvals required for this project? ☐ Yes ☐ No

	Date Application Submitted	Date Application Received
Stream Disturbance Permit (DEC)		
Wetlands Permit (DEC or Local)		
Floodplain Permit (DEC or Local)		
Other _____		

PREPARER'S SIGNATURE	DATE
NAME/TITLE (Please print)	
REPRESENTING	

Suggested Sources of Information for Division of Mineral Resources Environmental Assessment Form

3. LAND USE
   Sources: Local Planning Office
   Town Supervisor's Office
   Town Clerk's Office

5a. PRIMARY OR PRINCIPAL AQUIFER
   Sources: Local unit of government
   NYS Department of Health
   NYSDEC, Division of Water--Regional Office
   Availability of Water from Aquifers in New York State--United States Geological Survey
   Availability of Water from Unconsolidated Deposits in Upstate New York--United States Geological Survey

5b. PUBLIC WATER SUPPLY
   Sources: Local unit of government
   NYS Department of Health
   NYS Atlas of Community Water Systems Sources, NYS Department of Health, 1982
   Atlas of Eleven Selected Aquifers in New York State, United States Geological Survey, 1982

5c. AGRICULTURAL DISTRICT INFORMATION
   Sources: Cooperative Extension
   DEC, Division of Lands and Forests
   NYS Department of Agriculture and Markets
   DEC, Division of Environmental Permits--Regional Office
   DEC, Division of Mineral Resources--Regional Office

5f. SOIL AND WATER CONSERVATION PLAN
   Sources: Landowner
   County Soil and Water Conservation District Office

5g. 100 YEAR FLOOD PLAIN
   Sources: DEC Division of Water
   DEC, Division of Environmental Permits--Regional Office
   DEC, Division of Mineral Resources--Regional Office

5h. WETLANDS
   Sources: DEC, Division of Fish and Wildlife--Regional Office
   DEC, Division of Mineral Resources--Regional Office

5i. COASTAL ZONE MANAGEMENT AREAS
   Sources: Local unit of government
   NYS Department of State, Coastal Management Program
   DEC, Division of Water (maps)
   DEC, Division of Environmental Permits--Regional Office

5k. THREATENED OR ENDANGERED SPECIES
   Sources: DEC, Natural Heritage Program--Albany
   DEC, Division of Environmental Permits--Regional Office

6. ARCHEOLOGICAL OR HISTORIC RESOURCES
   Sources: NYS Office of Parks, Recreation and Historic Preservation circles and squares map
   DEC, Division of Environmental Permits--Regional Office

18. ADDITIONAL PERMITS NEEDED
   Sources: DEC, Division of Environmental Permits--Regional Office
   DEC, Division of Mineral Resources--Regional Office
   NYS Office of Business Permits

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New York State

DEC

Appendix 6

PROPOSED
Environmental Assessment Form
Addendum

Updated August 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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PROPOSED EAF ADDENDUM REQUIREMENTS
FOR HIGH-VOLUME HYDRAULIC FRACTURING

REQUIRED INFORMATION

- Minimum depth and elevation of top of objective formation or zone for entire length of wellbore
- Estimated maximum depth and elevation of bottom of potential fresh water, and basis for estimate (water well information, other well information, previous drilling at pad, published or private reports, etc.)
- Identification of proposed fracturing service company and additive products, by product name and purpose/type
    - Documentation of the applicant's evaluation of available alternatives for the proposed additive products that are efficacious but which exhibit reduced aquatic toxicity and pose less risk to water resources and the environment
- Proposed volume of water and each additive product to be used in hydraulic fracturing
- Proposed % by weight of water, proppants and each additive
- Water source for hydraulic fracturing
    - If a newly proposed surface water source (not previously approved by the Department as part of a well permit application):
        - Type of withdrawal (stream, lake, pond, groundwater, etc.)
        - Location of water withdrawal point, status of RBC approval if applicable
        - List and location of all private water wells within 500 feet of the proposed water withdrawal point
        - For proposed withdrawals from lakes and ponds:
            - Estimates of the maximum change in storage resulting from the proposed withdrawals, including estimates of inflow into the water body, precipitation onto water surface, existing and proposed water withdrawals, evaporation from water surface, and releases from water body
        - For proposed groundwater withdrawals:
            - Identification of and shortest distance to any wetland within 500 feet of the proposed withdrawal point
            - Results of pump testing as referenced in the SGEIS, including evaluation of any potential influence on wetland(s) within 500 feet
        - Indicate if an Article 15 permit is required and status
        - Size of drainage area above withdrawal point (in mi^2)
        - Indicate whether there is a USGS gage on the stream; if yes:
            - Distance to stream gage
            - Upstream or downstream of stream gage
            - Changes in stream flow (e.g., other withdrawals, diversions, tributary input) between gage and withdrawal point
            - Years of stream gage data available and period of record
    - If a previously proposed or Department-approved surface water source:
        - API # of well permit application associated with previous proposal or approval

- Scaled distance from surface location of well and closest edge of well pad to:
  - Any known water supply reservoir, river or stream intake, water well or domestic-supply spring within 2,640 feet, including public or private wells, community or non-community systems
  - Any primary or principal aquifer boundary, perennial or intermittent stream, wetland, storm drain, lake or pond within 660 feet
  - All residences, occupied structures or places of assembly within 1,320 feet
- Capacity of rig fueling tank(s) and distance to:
  - Any public or private water well, domestic-supply spring, reservoir, perennial or intermittent stream, storm drain, wetland, lake or pond within 500 feet of the planned location(s) of the fueling tank(s)
- Available information about water wells and domestic-supply springs within 2,640 feet
  - Well name and location
  - Distance from proposed surface location of well
  - Shortest distance from proposed well pad
  - Shortest distance from proposed centralized flowback water impoundment
  - Well depth
  - Well's completed interval
  - Public or private supply
  - Community or non-community system (see NYSDOH definitions)
  - Type of facility or establishment if not a residence
- Identification of any well listed in Department's Oil & Gas Database, or any other abandoned well identified by property owners or tenants, within the spacing unit of the proposed well and/or within 1 mile (5,280 feet) of the proposed well location. For each well identified, provide the following information:
  - Well name and API Number
  - Distance from proposed surface location of well to surface location of existing well
  - Well Type
  - Well Status
  - Well Orientation
  - Quantity and type of any freshwater, brine, oil or gas encountered during drilling, as recorded on the Department's Well Drilling and Completion Report
- Information about the planned construction and capacity of the reserve pit, if any, and an indication of the timing of the use of a closed-loop tank system (e.g., surface, intermediate and/or production hole)
- Information about the number and individual and total capacity of receiving tanks for flowback water
- If proposed flowback vent/flare stack height is less than 30 feet, then documentation that previous drilling at the pad did not encounter H_2S is required
- Description of planned public access restrictions, including physical barriers and distance to edge of well pad
- Identify the EPA Tiers of the drilling and hydraulic fracturing engines used, if these use gasoline or diesel fuel. If particulate traps or Selective Catalytic Reduction (SCR) are not used, provide a description of other control measures planned to reduce particulate matter and NO_x emissions during the drilling and hydraulic fracturing processes

- If condensate tanks are to be used, provide their capacity and the vapor recovery system to be used
- If a wellhead compressor is used, provide its size in horsepower. Describe the control equipment used for NO_x
- If a glycol dehydrator is to be used at the well pad, provide its stack height and the capacity of glycol to be used on an annual basis
- Information on the status of a sales line and interconnecting gathering line to the well or multi-well pad (i.e., is there currently a line in place or is one expected to be in place prior to conducting hydraulic fracturing operations to facilitate a Reduced Emissions Completion [REC])
    - If REC will not be used, the following must be provided
        - an estimate of how much total gas (MMcf) will be vented and flared during flowback
        - an estimate of how much total gas (MMcf) was previously vented and flared during flowback on the same well pad in the previous 12 months
- Well information with respect to local planning documents
    - Identify whether the location of the well pad, or any other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies
    - Identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s)

REQUIRED ATTACHMENTS

- Scaled, stamped well plat showing the following:
    - Plan view of wellbore including surface and bottom-hole locations
    - Well pad close-up showing placement of fueling tank(s), reserve pit and receiving tanks for flowback water
    - Vertical section of wellbore showing the land surface elevation and wellbore elevation with an indication of the minimum depth of the wellbore within the objective formation or zone as required above
- A Material Safety Data Sheet (MSDS) for each additive product proposed for use in hydraulic fracturing, if not already on file with the Department
- Topographic map of area within at least 2,640 feet of surface location showing:
    - above features and scaled distances
    - location and orientation of well pad
    - location of access road
    - location of any flowback water pipelines or conveyances
- Evidence of diligent efforts by the well operator to determine the existence of public or private water wells and domestic-supply springs within one half-mile (2,640 feet) of any proposed drilling location or centralized flowback water impoundment if proposed
    - List of municipal officials contacted for water well information and printed copies of responses
    - List of property owners and tenants contacted for water well information
    - List of adjacent lessees contacted for water well information

  - Printed results of EPA SDWIS search (http://oaspub.epa.gov/enviro/sdw_form_v2.create_page?state_abbr=NY)
  - Printed results of Department Water Well search (http://www.dec.ny.gov/cfmx/extapps/WaterWell/index.cfm?view=searchByCounty)
- Evidence of diligent efforts by the well operator to determine the existence and condition of abandoned wells within the proposed spacing unit and/or within one mile of the proposed well location
  - Printed results of Department Oil & Gas database search
  - List of property owners and tenants contacted for abandoned well information
- For a newly proposed water withdrawal, topographic map showing:
  - The location of the proposed withdrawal
  - All private water wells within 500 feet of the proposed water withdrawal point
  - For proposed surface water withdrawals:
    - Drainage area above the withdrawal point
  - For proposed groundwater withdrawals:
    - Identification of and shortest distance to any Department-regulated wetland within 500 feet of the proposed withdrawal point
- Invasive Species Management Plan that includes:
  - Survey of the entire well site, documenting the presence, location, and identity of any invasive plant species;
  - Specific protocols or best management practices for preventing the spread or introduction of invasive species at the site;
  - Specific protocols for the restoration of native plant cover on the site; and
  - Identification of any Certified Pesticide Applicator, if applicable.
- A Partial Site Reclamation Plan that describes the methods for partially reclaiming the site after well completion. Partial reclamation shall be compatible with sound environmental management practices and minimize negative environmental impacts.
- A description of methods for final reclamation of the well site following plugging of all the wells on the well pad. Reclamation methods shall be compatible with sound environmental management practices and minimize negative environmental impacts from the well pad.
- Proposed fluid disposal plan, pursuant to 6 NYCRR 554.1(c)(1)
  - Planned transport of flowback water and production brine off of well pad – trucking or piping
    - If piping, describe construction including size, materials, leak prevention and spill control measures
  - Planned disposition of flowback water and production brine – treatment facility, disposal well, reuse on same well pad, reuse on another well pad, centralized flowback surface water impoundment, centralized tank facility, or other (describe)
    - If a treatment facility in NY:
      - Name, owner/operator, location
      - SPDES permit # and date if applicable
      - If a POTW, date of Department approval to receive flowback water (attach a copy of approval notification)
      - Brief description of facility and treatment if not a POTW

        - If a disposal well in NY:
            - SPDES permit # and date
            - EPA UIC permit # and date
        - If a centralized tank facility in New York:
            - Location, affirmation of ownership or permission
            - Certification of compliance with 360-6.3
- Proposed cuttings disposal plan for any drilling requiring cuttings to be disposed of off-site including at a landfill.
    - Planned disposition of cuttings – landfill or other (describe)
        - If a landfill in NY:
            - Name, owner/operator, location
            - Part 360 permit # and date if applicable
- Proposed blow-out preventer (BOP) use and test plan for all drilling and completion operations including:
    - Pressure rating of any:
        - Annular preventer
        - Rams including a description of type and number of rams
        - Choke manifold and connecting line (from BOP to choke manifold)
    - Timing and frequency of testing and/or visual inspection of BOP and related equipment including any scheduled retesting of equipment. Test pressure(s) and duration of test(s) including an explanation as to how the test pressure was determined
    - Test pressure(s) and timing for any internal pressure testing of surface, intermediate and production casing strings, and duration of test including an explanation as to how the test pressure was determined
    - Test pressure (psi/ft) and anticipated depth (TVD-ft) of any surface and/or intermediate casing seat integrity tests
        - If a casing seat integrity test will not be conducted on a casing string with a BOP installed on it, an explanation must be provided why such a test is not required and how any flow will be managed
    - System for recording, documenting and retaining the results of all pressure tests and inspections, and making such available to the Department
    - Copy of the operator's well control barrier policythat identifies acceptable barriers to be used during identified operations
    - Minimum distance from well for remote actuator (powered by a source other than rig hydraulics)
- Transportation plan developed by a NYS-licensed Professional Engineer, that specifies proposed routes and includes a road condition assessment.
- Noise mitigation plan, including any proposed mitigation measures for any occupied structure within 1,000 feet.
- If a new well pad is proposed in a Forest or Grassland Focus Area and involves disturbance in a contiguous forest patch of 150 acres or more in size or a contiguous grassland patch of 30 acres or more in size, then the Applicant should not submit this EAF or a well permit application prior to conducting a site-specific ecological assessment in accordance with a

detailed study plan that has been approved by the Department. The need and plan for an ecological assessment should be determined in consultation with the Department and will consider information such as existing site conditions, existing covertype and ongoing and historical land management activities. The completed ecological assessment must be attached to this EAF and must include, at a minimum:

- a compilation of historical information on use of the area by forest interior birds or grassland birds;
- results of pre-disturbance biological studies, including a minimum of one year of field surveys at the site to determine the current extent, if any, of use of the site by forest interior birds or grassland birds;
- an evaluation of potential impacts on forest interior or grassland birds from the project;
- additional mitigation measures proposed by the applicant; and
- protocols for monitoring of forest interior or grassland birds during the construction phase of the project and for a minimum of two years following well completion.

REQUIRED AFFIRMATIONS

- Any surface water withdrawal associated with this well pad will only occur when flow is above the appropriate threshold as described in the SGEIS
- Applicable FIRM and Flood Boundary and Floodway maps consulted, and proposed well pad and access road are not within a mapped100-year floodplain
- Baseline residential well sampling, analysis and ongoing monitoring will be conducted and results shared with property owner as described in SGEIS and permit conditions
- Unless otherwise required by private lease agreement, the access road will be located as far as practical from occupied structures, places of assembly and unleased property
- HVHF GP authorization for stormwater discharges will be obtained prior to site disturbance
- Operator will prepare and adhere to the following site plans, which will be available to the Department upon request and available on-site to Department inspector while activities addressed by the plan are occurring:
    - a visual impacts mitigation plan consistent with the SGEIS
    - a noise impacts mitigation plan consistent with the SGEIS
    - a greenhouse gas impacts mitigation plan consistent with the SGEIS
    - an invasive species mitigation plan which includes:
        - -the best management practices listed in the SGEIS and
        - seasonally appropriate site-specific and species-specific physical and chemical control methods (e.g., digging to remove all roots, cutting to the ground, applying herbicides to specific plant parts such as stems or foliage, etc.) based on the invasive species survey submitted with the EAF Addendum
    - an acid rock drainage (ARD) mitigation plan consistent with the SGEIS for on-site burial of Marcellus Shale cuttings from horizontal drilling in the Marcellus Shale if the operator elects to bury these cuttings
- Operator will utilize alternative hydraulic fracturing additive products that exhibit reduced aquatic toxicity and pose less risk to water resources and the environment, unless demonstrated to DMN's satisfaction that they are not equally effective or feasible

- Operator will prepare and adhere to an emergency response plan (ERP) consistent with the SGEIS that will be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. -A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit
- Operator will adhere to all well permit conditions and approved plans, including requirement for Department approval prior to making any change
- Operator will adhere to best management practices for reducing direct impacts to terrestrial habitats and wildlife consistent with the SGEIS (see Section 7.4.1.1)

ADDITIONAL SUBMISSION REQUIRED PRIOR TO SITE DISTURBANCE

- Copy of any road use agreement between the operator and local municipality

ADDITIONAL SUBMISSION REQUIRED AT LEAST 48 HOURS PRIOR TO WELL SPUD

- Copy of the ERP in electronic form

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Appendix 7

Sample Drilling Rig Specifications

Provided by Chesapeake Energy

Revised Draft
Supplemental Generic Environmental Impact Statement

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ATTACHMENT A
RIG SPECIFICATIONS
Example #1

National Cabot 900
Working Depth: 12,000'

DRAWWORKS:	National Model 2346 – Mechanical – Grooved for 1 1/8'' drilling line. Air operated, water cooled Eaton Assist Brake
ENGINES:	2 - Cat C-15 (475HP ea.) with Allison Transmissions
MAST:	NOV - 117' - 350,000 SHL on 8 lines
SUBSTRUCTURE:	NOV - 18' Floor Height /15' Working Height
TRAVELING EQUIPMENT:	IDECO UTB – 265 Ton Block and Hook
ROTARY TABLE:	27 ½'' with 440,000# capacity
TUBULARS:	12,000' - S-135 - 4 1/2''x 16.60# per foot w/ XH connections 18 - 6 ½'' collars with NC46 connections
MUD PUMPS:	2 – National 9-P-100 with Cat 3508 Mechanicals (935HP ea.)
MUD SYSTEM:	3 - Tank, 900 BBL total
SOLIDS CONTROL EQUIPMENT:	Shakers: 2 – NOV D285P-LP Desander: Brandt - 2 - 10" Cones Desilter: Brandt - 12 - 4" Cones Agitators: 6 – Brandt with 36'' Impellers
BOP EQUIPMENT:	1 - Shaffer LXT - 11" 5M - Double Ram 1 – Shaffer Spherical - 11" 5M - Annular
CLOSING UNIT:	Koomey - 6 Station - 160 Gallon; 3000 psi
CHOKE MANIFOLD:	3'' x 4'' - 5M, 1 Hydraulic Choke and 1 Manual Choke
GENERATORS:	2 - Caterpillar 545 kW, Powered by 2 Cat C-18's
AUXILARY EQUIPMENT:	Water Tank: 400 BBL Fuel Tank: 10,000 Gallons
SPECIAL TOOLS:	2 - Braden PD12C Hydraulic Hoist Hydraulic Pipe Spinner Oil Works OWI-1000 Wire line with 12,000' of wire

Rig Specifications
Example #2

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610 Mechanical 750 HP
Working Depth: 14,000'

DRAWWORKS: National 610 Mechanical
Wichita 325 Air Brake

ENGINES: 2 – Caterpillar C-18's, 600 HP Each

MAST: Dreco 142' 550,000 SHL on 10 Lines

SUBSTRUCTURE: Dreco 20' Box on Box

TRAVELING EQUIPMENT: Block-Hook: Ideco UTB-265-5-36

ROTARY TABLE: National C-275

COMPOUND: National 2 Engines

TORQUE CONVERTERS: 2 – National C195

MUD PUMPS: 2 – National 9-P-100, Independent Drive Cummins QSK38, 920 HP

MUD SYSTEM: 2 – Tank, 750 BBL total w/100 BBL Premix

SOLIDS CONTROL EQUIPMENT:
Shakers: 2 – National Model DLMS-285P
Desander: National with 2 - 10" Cones
Desilter: National with 16 - 4" Cones

BOP EQUIPMENT: 1 – Shaffer LWS Type 11" 5M
1 – Shaffer Spherical Type 11: 5M

CLOSING UNIT: Koomey 6 Station 180 Gallon; 1 Air and 1 Electrical Pump

CHOKE MANIFOLD: 4'' x 3'' 5M, 2 Adjustable Chokes

GENERATORS: 2 – Cat 545 kW, Powered by 2 Cat C-18's

AUXILARY EQUIPMENT:
Water Tank: 500 BBL
Fuel Tank: 12,000 Gallons

SPECIAL TOOLS:
ST-80 Iron Roughneck
Pipe Spinner: Hydraulic
Auto Driller: Satellite
Totco EDR (Rental)
Separator/Trip Tank Combo (Rental)
Hoists: 1 – Thern 2.5A Air Hoist
1 - Braden PD12C Hydraulic Hoist

Rig Specifications
Example #3

SpeedStar 185K -- 515 HP
Working Depth: 8,000'

ENGINE: 1 – Caterpillar C-15 with Allison Transmission

MAST: SpeedStar – 61' – 185,000 LB SHL
Setback Capacity of 7,000' – 3.5" Drill Pipe

SUBSTRUCTURE: Box Type – 7'6" Working Height

MUD PUMP: 1 – MP5

MUD SYSTEM: 2 – Tank, 600 BBL

BOP EQUIPMENT: 11" x 3M Annular

CLOSING UNIT: Townsend 4 Station, 80 Gallon

CHOKE MANIFOLD: 3'' x 3'' 5K with 1 Hydraulic Choke

GENERATORS: 2 – Onan 320 kW with Cummins Engines

DRILL PIPE: 7,500' OF 3.5" 13.30 LB/FT with IF Connections

DRILL COLLARS: 12 – 6 ½"

AIR SYSTEM: 3 – Ingersoll Rand 1170/350 Air Compressors
2 – Single Stage Boosters

AUXILARY EQUIPMENT: Water Tank: 250 BBL
Fuel Tank: 3,500 Gallons

SPECIAL TOOLS: 2 – Braden PD12C Hydraulic Tub Winches
Myers 35GPM Soap Pump
Martin Decker Geolograph
Wireline Unit with 10,000' of Line

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Appendix 8

Casing & Cementing Practices Required for All Wells in NY

Revised Draft
Supplemental Generic Environmental Impact Statement

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New York State Department of Environmental Conservation
Casing and Cementing Practices

SURFACE CASING

1. The diameter of the drilled surface casing hole shall be large enough to allow the running of centralizers in recommended hole sizes.

RECOMMENDED CENTRALIZER-HOLE SIZE COMBINATIONS		
Centralizer Size Inches	**Minimum Hole Sizes Inches**	**Minimum Clearance Inches**
4-1/2	6-1/8	1-5/8
5-1/2	7-3/8	1-7/8
6-5/8	8-1/2	1-7/8
7	8-3/4	1-3/4
8-5/8	10-5/8	2
9-5/8	12-1/4	2-5/8
13-3/8	17-1/2	4-1/8

NOTE: (1) If a manufacturer's specifications call for a larger hole size than indicated in the above table, then the manufacturer's specs take precedence.

(2) Check with the appropriate regional office for sizes not listed above.

2. Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper, unless otherwise approved by the Department. However, the surface pipe must be set deeply enough to allow the BOP stack to contain any formation pressures that may be encountered before the next casing is run.

3. Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).

4. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi), unless otherwise approved. Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.

5. Centralizers shall be spaced at least one per every 120 feet; a minimum of two centralizers shall be run on surface casing. Cement baskets shall be installed appropriately above major lost circulation zones.

6. Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the bore hole spacer or extra cement shall be used to separate the cement from the bore hole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.

7. The pump and plug method shall be used to cement surface casing, unless approved otherwise by the Department. The amount of cement will be determined on a site-specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless other amounts of excesses are approved or specified by the Department.

8. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing ticket.

9. The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.

10. After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The waiting-on-cement (WOC) time shall be recorded on the drilling log.

11. When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the well bore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, three feet in diameter and shall be crowned up to the drive pipe (conductor casing), unless otherwise approved by the Department.

WHEN REQUESTED BY THE DEPARTMENT IN WRITING, EACH OPERATOR MUST SUBMIT CEMENT TICKETS AND/OR OTHER DOCUMENTS THAT INDICATE THE ABOVE SPECIFICATIONS HAVE BEEN FOLLOWED.

THE CASING AND CEMENTING PRACTICES ABOVE ARE DESIGNED FOR TYPICAL SURFACE CASING CEMENTING. THE DEPARTMENT WILL REQUIRE ADDITIONAL MEASURES FOR WELLS DRILLED IN ENVIRONMENTALLY OR TECHNICALLY SENSITIVE AREAS (i.e., PRIMARY OR PRINCIPAL AQUIFERS).

THE DEPARTMENT RECOGNIZES THAT VARIATIONS TO THE ABOVE PROCEDURES MAY BE INDICATED IN SITE SPECIFIC INSTANCES. SUCH VARIATIONS WILL REQUIRE THE PRIOR APPROVAL OF THE REGIONAL MINERAL RESOURCES OFFICE STAFF.

INTERMEDIATE CASING

Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.

PRODUCTION CASING

12. The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.

13. Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.

14. The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the

lowest (deepest) full joint of casing.

15. The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.

16. Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.

17. The annular space between the surface casing and the production string shall be vented at all times. If the annular gas is to be produced, a pressure relief valve shall be installed in an appropriate manner and set at a pressure approved by the Regional Mineral Resources office.

WHEN REQUESTED BY THE DEPARTMENT IN WRITING, EACH OPERATOR MUST SUBMIT CEMENT TICKETS AND/OR OTHER DOCUMENTS THAT INDICATE THE ABOVE SPECIFICATIONS HAVE BEEN FOLLOWED.

THE CASING AND CEMENTING PRACTICES ABOVE ARE DESIGNED FOR TYPICAL PRODUCTION CASING/ CEMENTING. THE DEPARTMENT WILL REQUIRE ADDITIONAL MEASURES FOR WELLS DRILLED IN ENVIRONMENTALLY OR TECHNICALLY SENSITIVE AREAS (i.e., PRIMARY OR PRINCIPAL AQUIFERS).

THE DEPARTMENT RECOGNIZES THAT VARIATIONS TO THE ABOVE PROCEDURES MAY BE INDICATED IN SITE SPECIFIC INSTANCES. SUCH VARIATIONS WILL REQUIRE THE PRIOR APPROVAL OF THE REGIONAL MINERAL RESOURCES OFFICE.

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Appendix 9

EXISTING
Fresh Water Aquifer Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers

Revised Draft
Supplemental Generic Environmental Impact Statement

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FRESH WATER AQUIFER SUPPLEMENTARY PERMIT CONDITIONS

Operator: Well Name:
API Number:

1. All pits must be lined and sized to fully contain all drilling, cementing and stimulation fluids plus any fluids as a result of natural precipitation. Use of these pits for any other purpose is prohibited.

2. All fluids must be contained on the site and properly disposed. If operations are suspended and the site is left unattended at any time, pit fluids must be removed from the site immediately. After the cessation of drilling and/or stimulation operations, pit fluids must be removed within 7 days. Disposal of fluids must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit.

3. Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.

4. If conductor pipe is used, it must be run in a drilled hole and it must be cemented back to surface by circulation down the inside of the pipe and up the annulus, or installed by another procedure approved by this office. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, at least two centralizers must be run with one each at the shoe and at the middle of the string. In the event that cement circulation is not achieved, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the conductor casing and squeeze cementing of perforations. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present.

5. A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. If shallow gas is known to exist or is anticipated in this bedrock interval, the casing setting depth may be adjusted based on site-specific conditions provided it is approved by this office. There must be at least a 2½" difference between the diameters of the hole and the casing (excluding couplings) or the clearance specified in the Department's Casing and Cementing Practices, whichever is greater. Cement must be circulated back to the surface with a minimum calculated 50% excess. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, cement baskets and centralizers must be run at appropriate intervals with centralizers run at least every 120'. Pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 psi or reconditioned pipe that has been tested internally to a minimum of 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to this office before the pipe is run. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present.

6. If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.

7. In the event that cement circulation is not achieved on any surface casing cement job, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the surface casing and squeeze cementing of perforations. This office may also require that a cement bond log and/or other logs be run for evaluation purposes. In addition, drilling out of and below surface casing cannot commence if there is any evidence or indication of flow behind the surface casing until remedial action has occurred. Alternative remedial actions from those described above may be approved by this office on a case-by-case basis provided site-specific conditions form the basis for such proposals.

8. This office must be notified _____ hours prior to any stimulation operation. Stimulation may commence without the state inspector if the inspector is not on location at the time specified during the notification.

9. The operator must complete the "Record of Formations Penetrated" on the Well Drilling and Completion Report providing a log of formations, both unconsolidated and consolidated, and all water and gas producing zones.

10. If the well is a producer, holding tanks with water-tight diking capable of retaining 1½ times the capacity of the tank must be installed for the containment of oil, brine and other production fluids. Disposal of fluids must only be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit.

11. **Any deviation from the above conditions must be approved by the Department prior to making a change.**

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Appendix 10

PROPOSED
Supplementary Permit Conditions
For High-Volume Hydraulic Fracturing

Updated August 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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PROPOSED Supplementary Permit Conditions for High-Volume Hydraulic Fracturing

Note: The operator must comply with all provisions of Attachment A and Attachment B as noted at the end of this document, along with Attachment C when applicable.

Planning and Local Coordination

1) All operations authorized by this permit must be conducted in accordance with the following site-specific plans prepared by the operator, available to the Department upon request, and available on-site to a Department inspector while activities addressed by the plan are taking place:

   a) a visual impacts mitigation plan consistent with the SGEIS; and

   b) a greenhouse gas emissions impacts mitigation plan consistent with the SGEIS.

2) An emergency response plan (ERP) consistent with the SGEIS must be prepared by the well operator and be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit. Further, a copy of the ERP in electronic form must be provided to this office at least 3 days prior to well spud.

3) The county emergency management office (EMO) must be notified of the well's location including latitude and longitude (NAD 83) as follows:

   a) prior to spudding the well;

   b) first occurrence of flaring while drilling;

   c) prior to high-volume hydraulic fracturing, and;

   d) prior to flaring for well clean-up, treatment or testing. A flare permit from the Department is required prior to any flaring operation for well clean-up, treatment or testing.

   A record of the type, date and time of any notification provided to the EMO must be maintained by the operator and made available to the Department upon request. In counties without an EMO, the local fire department must be notified as described above.

4) The operator shall adhere to the Department-approved transportation plan which shall be incorporated by reference into this permit. In addition, issuance of this permit does not provide relief from any local requirements authorized by or enacted pursuant to the New York State Vehicle and Traffic Law. Prior to site disturbance, the operator shall submit to the Department a copy of any road use agreement between the operator and municipality.

5) Prior to site disturbance (for a new well pad) or spud (for an existing pad), the operator must sample and test residential water wells within 1,000 feet of the well pad as described by the SGEIS, and provide results to the property owner within 30 days of the operator's receipt of

laboratory results. If no residential water wells are available for sampling within 1,000 feet, either because there are none of record or because the property owner denies permission, then wells within 2,000 feet must be sampled and tested with the property owner's permission.

6) Ongoing water well monitoring and testing must continue as described by the SGEIS until one year after hydraulic fracturing at the last well on the pad. More frequent or additional monitoring and testing may be required by the Department in response to complaints or for other reasonable cause.

7) Water well analysis must be performed by an ELAP-certified laboratory. Analyses and documentation that all test results were provided to the property owner must be maintained by the operator. The results of the analyses (data) and delivery documentation must be made available to the Department and local health department upon Department request at any time during the period up to and including five years after the permitted hydrocarbon well is permanently plugged and abandoned under a Department permit. If the permitted hydrocarbon well is located on a multi-well pad, all residential water well data and delivery documentation must be maintained and made available during the period up to and including five years after the last permitted hydrocarbon well on the pad is permanently plugged and abandoned under a Department permit.

Site Preparation

8) Unless otherwise required by private lease agreement and in consideration of avoiding bisection of agricultural fields, to the extent practical the access road must be located as far away as possible from occupied structures, places of assembly and unleased property.

9) Unless otherwise approved or directed by the Department, all of the topsoil in the project area stripped to facilitate the construction of well pads and access roads must be stockpiled, stabilized and remain on site for use in final reclamation.

10) Authorization under the Department's General Permit for Stormwater Discharges Associated with High-Volume Hydraulic Fracturing (HVHF GP) must be obtained prior to any disturbance at the site.

11) Piping, conveyances, valves and tanks in contact with flowback water must be constructed of materials compatible with flowback water composition, and in accordance with the fluid disposal plan approved by the Department pursuant to 6 NYCRR 554.1(c)(1).

12) Any reserve pit, drilling pit or mud pit on the well pad which will be used for more than one well must be constructed as follows:

    a) Surface water and stormwater runoff must be diverted away from the pit;

    b) Pit volume may not exceed 250,000 gallons, or 500,000 gallons for multiple pits on one tract or related tracts of land;

    c) Pit sidewalls and bottoms must adequately cushioned and free of objects capable of puncturing and ripping the liner;

    d) Pits constructed in unconsolidated sediments must have beveled walls (45 degrees or less);

e) The pit liner must be sized and placed with sufficient slack to accommodate stretching;

f) Liner thickness must be at least 30 mils, and;

g) Seams must be factory installed or field seamed in accordance with the manufacturer's recommendations.

Site Maintenance

13) Secondary containment consistent with the Department's Spill Prevention Operations Technology Series 10, Secondary Containment Systems for Aboveground Storage Tanks, (SPOTS 10) is required for all fueling tanks;

14) To the extent practical, fueling tanks must not be placed within 500 feet of a public or private water-well, a domestic-supply spring, a reservoir, a perennial or intermittent stream, a storm drain, a wetland, a lake or a pond;

15) Fueling tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck, and;

16)Troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment.

17) A copy of the SWPPP must be available on-site and available to Department inspectors while HVHF GP coverage is in effect. HVHF GP coverage may be terminated upon the plugging and abandonment of all wells on the well pad in accordance with Department-issued permits.

18) Two feet of freeboard must be maintained at all times for any on-site pit.

19) Except for freshwater storage pits, fluids must be removed from an on-site pit prior to any 45-day gap in use (i.e., from the completion date of the well) and the pit must be inspected by a Department inspector prior to resumed use.

Drilling, Stimulation and Flowback

NOTE: Wildcat Supplementary Conditions may be separately imposed in addition to these. Unless superseded by more stringent conditions below, the Department's Casing and Cementing Practices also remain in effect.

20) Lighting and noise mitigation measures as deemed necessary by the Department may be required at any time.

21) The operator must provide the drilling company with a well prognosis indicating anticipated formation top depths with appropriate warning comments prior to spud. The prognosis must be reviewed by all crew members and posted in a prominent location in the doghouse. The operator must revise the prognosis and inform the drilling company in a timely manner if

drilling reveals significant variation between the anticipated and actual geology and/or formation pressures.

22) Individual crew member's responsibilities for blowout control must be posted in the doghouse or other appropriate location and each crew member must be made aware of such responsibilities prior to spud of any well being drilled or when another rig is moved on a previously spudded well and/or prior to the commencement of any rig, snubbing unit or coiled tubing unit performing completion work. During all drilling and/or completion operations when a BOP is installed, tested or in use, the operator or operator's designated representative must be present at the wellsite and such person or personnel must have a current well control certification from an accredited training program that is acceptable to the Department (e.g., International Association of Drilling Contractors). Such certification must be available at the wellsite and provided to the Department upon request.

23) Appropriate pressure control procedures and equipment in proper working order must be properly installed and employed while conducting drilling and/or completion operations including tripping, logging, running casing into the well, and drilling out solid-core stage plugs. Unless otherwise approved by the Department, a snubbing unit and/or coiled tubing unit with a BOP must be used to enter any well with pressure and/or to drill out one or more solid-core stage plugs.

24) Pressure testing of the blow-out preventer (BOP) and related equipment for any drilling and/or completion operation must be performed in accordance with the approved BOP use and test plan, and any deviation from the approved plan must be approved by the Department. Testing must be conducted in accordance with American Petroleum Institute (API) Recommended Practice (RP) 53, RP for Blowout Prevention Systems for Drilling Wells, or other procedures approved by the Department. Unless otherwise approved by the Department, the BOP use and test plan must include the following provisions:

    a) A system for recording, documenting and retaining the results of all pressure tests and inspections conducted during drilling and/or completion operations. The results must be available to the Department at the wellsite during the corresponding operation, and to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all pressure testing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit. The record for each pressure test, at a minimum, must identify the equipment or casing being tested, the date of the test, the minimum and maximum test pressures in psig, the test medium (e.g., water, brine, mud, air, nitrogen) including its density, test duration, and the results of the test including any pressure drop;

    b) A well control barrier policy developed by the operator that identifies acceptable barriers to be used during identified operations. Such policy must employ, at a minimum, two mechanical barriers capable of being tested when conducting any drilling and/or completion operation below the surface casing. In no event shall a stripper rubber or a stripper head be considered an acceptable barrier;

    c) BOP testing prior to being put into service. Such testing must include testing after the BOP is installed on the well but prior to use. Pressure control equipment,

including the BOP, that fails any pressure test must not be used until it is repaired and passes the pressure test, and;

d) A remote BOP actuator which is powered by a source other than rig hydraulics that is located at least 50 feet from the wellhead. All lines, valves and fittings between the BOP and the remote actuator and any other actuator must be flame resistant and have an appropriate rated working pressure.

25) The operator must detect, if practical, and document all naturally occurring methane in the conductor hole, if drilled, and the surface hole. Further, in accordance with 6 NYCRR 554.7(b), all freshwater, brine, oil and gas shows must be documented on the Department's *Well Drilling and Completion Report*. In the event H_2S is encountered in any portion of the well, all regulated activities must be conducted by the operator in conformance with American Petroleum Institute Publication API RP49, "Recommended Practices For Safe Drilling of Wells Containing Hydrogen Sulfide."

26) Annular disposal of drill cuttings or fluid is prohibited.

27) All fluids must be contained on the site until properly removed in compliance with the fluid disposal plan approved in accordance with 6 NYCRR 554.1(c)(1) and applicable conditions of this permit.

28) A closed-loop tank system must be used instead of a reserve pit to manage and contain drilling fluids and cuttings for any of the following:

a) horizontal drilling in the Marcellus Shale without an acid rock drainage mitigation plan for on-site burial of such cuttings, and;

b) any drilling requiring cuttings to be disposed of off-site including at a landfill.

29) With respect to the closed-loop tank system, cuttings may be removed from the site in the primary capture container (e.g., tank or bin) or transferred onsite via a transfer area to a secondary container or truck for offsite disposal. If a cuttings transfer area is employed, it must be lined with a material acceptable to the department. Transfer of cuttings to an onsite stock pile is prohibited, regardless of any liner under the stock pile. Offsite transport of all cuttings must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit. The *Drilling and Production Waste Tracking Form* must be completed and retained for three years by the generator, transporter and destination facility, and made available to the Department upon request during this period. If requested, the generator is responsible for producing its originating copy of the *Drilling and Production Waste Tracking Form* and the completed form with the original signatures of the generator, transporter and destination facility.

30) Only biocides with current registration for use in New York may be used for any operation at the wellsite. Products must be properly labeled, and the label must be kept on-site during application and storage.

31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:

a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;

b) casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);

c) at least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);

d) cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive;

e) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

f) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

g) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;

h) after the cement is pumped, the operator must wait on cement (WOC):
   1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and
   2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig, and;

i) A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.

32) The surface casing must be run and cemented immediately after the hole has been adequately circulated and conditioned. This office must be notified _____ hours prior to surface

casing cementing operations. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

33) Intermediate casing must be installed in the well. The setting depth and design of the casing must consider all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the Department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may serve to form the basis for the Department waiving the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.

34) This office must be notified _____ hours prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess will suffice. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

35) The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).

36) Production casing must be run to the surface. This office must be notified _____ hours prior to production casing cementing operations. If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD). Any request to waive any of the preceding cementing requirements must be made in writing with supporting documentation and is subject to the Department's approval. The Department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will be prevented. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

37) The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.

38) The installation of an additional cemented casing string or strings in the well as deemed necessary by the Department for environmental and/or public safety reasons may be required at any time.

39) Under no circumstances should the annulus between the surface casing and the next casing string be shut-in, except during a pressure test.

40) If hydraulic fracturing operations are performed down casing, prior to introducing hydraulic fracturing fluid into the well the casing extending from the surface of the well to the top of the treatment interval must be tested with fresh water, mud or brine to at least the maximum anticipated treatment pressure for at least 30 minutes with less than a 5% pressure loss. This pressure test may not commence for at least 7 days after the primary cementing operations are completed on this casing string. A record of the pressure test must be maintained by the operator and made available to the Department upon request. The actual hydraulic fracturing treatment pressure must not exceed the test pressure at any time during hydraulic fracturing operations.

41) Prior to commencing hydraulic fracturing and pumping of hydraulic fracturing fluid, the injection lines and manifold, associated valves, frac head or tree and any other wellhead component or connection not previously tested must be tested with fresh water, mud or brine to at least the maximum anticipated treatment pressure for at least 30 minutes with less than a 5% pressure loss. A record of the pressure test must be maintained by the operator and made available to the Department upon request. The actual hydraulic fracturing treatment pressure must not exceed the test pressure at any time during hydraulic fracturing operations.

42) The operator must record the depths and estimated flow rates where fresh water, brine, oil and/or gas were encountered or circulation was lost during drilling operations. This information and the Department's *Pre-Frac Checklist and Certification* form including a treatment plan, must be submitted to and received by the regional office at least 3 days prior to commencement of high-volume hydraulic fracturing operations. The treatment plan must include a profile showing anticipated pressures and volumes of fluid for pumping the first stage. It must also include a description of the planned treatment interval for the well [i.e., top and bottom of perforations expressed in both True Vertical Depth (TVD) and True Measured Depth (TMD)].

43) Fracturing products other than those identified in the well permit application materials may not be used without specific approval from this office.

44) This permit does not authorize the use of diesel as the primary carrier fluid (i.e., diesel-based hydraulic fracturing).

45) The operator may conduct hydraulic fracturing operations provided 1) all items on the checklist are affirmed by a response of "Yes," 2) the *Pre-Frac Checklist And Certification* and treatment plan are received by the Department at least 3 days prior to hydraulic fracturing, and 3) all other pre-frac notification requirements are met as specified elsewhere. The operator is prohibited from conducting hydraulic fracturing operations on the well without additional Department review and approval if a response of "No" is provided to any of the items in the *Pre-Frac Checklist and Certification*.

46) Hydraulic fracturing operations must be conducted as follows:

a) Secondary containment for fracturing additive containers and additive staging areas, and flowback tanks is required. Secondary containment measures may include, as deemed appropriate by the Department, one or a combination of the following; dikes, liners, pads, impoundments, curbs, sumps or other structures or equipment capable of containing the substance. Any such secondary containment must be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area. No more than one hour before initiating any hydraulic fracturing stage, all secondary containment must be visually inspected to ensure all structures and equipment are in place and in proper working order. The results of this inspection must be recorded and documented by the operator, and available to the Department upon request;

b) At least two vacuum trucks must be on standby at the wellsite during the pumping of hydraulic fracturing fluid and during any subsequent flowback phases;

c) Hydraulic fracturing additives must be removed from the site if the site will be unattended;

d) Any hydraulic fracturing string, if used, must be either stung into a production liner or run with a packer set at least 100 feet below the deepest cement top. An adequately sized, function tested relief valve and an adequately sized diversion line must be installed and used to divert flow from the hydraulic fracturing string-casing annulus to a covered watertight steel tank or covered watertight tank made of another material approved by the Department in case of hydraulic fracturing string failure. The relief valve must be set to limit the annular pressure to no more than 95% of the working pressure rating of the casings forming the annulus. The annulus between the hydraulic fracturing string and casing must be pressurized to at least 250 psig and monitored;

e) The pressure exerted on treating equipment including valves, lines, manifolds, hydraulic fracturing head or tree, casing and hydraulic fracturing string, if used, must not exceed 95% of the working pressure rating of the weakest component;

f) The hydraulic fracturing treatment pressure must not exceed the test pressure of any given component at any time during hydraulic fracturing operations;

g) All annuli available at the surface must be continuously observed or monitored in order to detect pressure or flow, and the records of such maintained by the operator and made available to the Department upon request, and;

h) Hydraulic fracturing pumping operations must be immediately suspended if any anomalous pressure and/or flow condition is indicated or occurring including a significant deviation from the treatment plan (i.e., profile showing anticipated pressures and volume of fluid for pumping the first stage) provided to the Department with the *Pre-Frac Checklist and Certification* or any other anticipated pressure and/or flow condition. Suspension of operations due to an anomalous pressure and/or flow condition is considered a non-routine incident which must be reported in accordance with the General Provisions of these supplementary permit conditions. In the case of suspended hydraulic fracturing pumping operations and non-routine incident reporting of such, the operator must receive Department approval prior to recommencing hydraulic fracturing activities in the same well.

47) The operator must make and maintain a complete record of its hydraulic fracturing operation including the flowback phase, and provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all hydraulic fracturing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit. The record for each well must include all types and volumes of materials, including additives, pumped into the well, flowback rates, and the daily and total volumes of fluid recovered during the first 30 days of flow from well. The record must also include a complete description of pressures exhibited throughout the hydraulic fracturing operation and must include pressure recordings, charts and/or a pressure profile. A synopsis of the hydraulic fracturing operation must be provided in the appropriate section of the Department's *Well Drilling and Completion Report* which must be provided to the Department within 30 days after completing the well in accordance with 6 NYCRR 554.7.

48) Flowback water is prohibited from being directed to or stored in any on-site pit. Covered watertight steel tanks or covered watertight tanks constructed of another material approved by the Department are required for flowback handling and containment on the well pad. Flowback water tanks, piping and conveyances, including valves, must be constructed of suitable materials, be of sufficient pressure rating and be maintained in a leak-free condition. Fluid transfer operations from tanks to tanker trucks must be manned at the truck and at the tank if the tank is not visible to the truck operator from the truck. Additionally, during transfer operations, all interconnecting piping must be manned if not visible to transfer personnel at the truck and tank.

49) The venting of any gas originating from the target formation during the flowback phase must be through a flare stack at least 30 feet in height, unless the absence of H_2S has been demonstrated at a previous well on the same pad. Gas vented through the flare stack must be ignited whenever possible. The stack must be equipped with a self-ignition device.

50) A reduced emissions completion, with minimal flaring (if any), must be performed whenever a sales line and interconnecting gathering line are available during completion at any individual well or a multi-well pad.

51) This permit authorizes a one-time single-stage or multi-stage high-volume hydraulic fracturing operation as described in the well permit application materials, subject to the *Pre-Frac Checklist and Certification* and any modifications required by the Department. Any subsequent high-volume re-fracturing operations are subject to the Department's approval after:
    a) review of the planned fracturing procedures and products, water source, proposed site disturbance and layout, and fluid disposal plans;

    b) a site inspection by Department staff, and;

    c) a determination of whether any other Department permits are required.

Reclamation

52) Fluids must be removed from any on-site pit and the pit reclaimed no later than 45 days after completion of drilling and stimulation operations at the last well on the pad, unless the

Department grants an extension pursuant to 6 NYCRR 554.1(c)(3). Flowback water must be removed from on-site tanks within the same time frame.

53) Removed pit fluids must be disposed, recycled or reused as described in the approved fluid disposal plan submitted pursuant to 6 NYCRR 554.1(c)(1). Transport of all waste fluids by vehicle must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit. The *Drilling and Production Waste Tracking Form* must be completed and retained for three years by the generator, transporter and destination facility, and made available to the Department upon request during this period. If requested, the generator is responsible for producing its originating copy of the *Drilling and Production Waste Tracking Form* and the completed form with the original signatures of the generator, transporter and destination facility.

54) If any fluid or other waste material is moved off site by pipeline or other piping, the operator must maintain a record of the date and time the fluid or other material left the site, the quantity of fluid or other material, and its intended disposition and use at that destination or receiving facility.

55) Cuttings contaminated with oil-based mud and polymer-based muds must be contained and managed in a closed-loop tank system and not be buried on site, and must be removed from the site for disposal in a 6 NYCRR Part 360 solid waste facility. Consultation with the Department's Division of Materials Management (DMM) is required prior to disposal of any cuttings associated with water-based mud-drilling and pit liner associated with water-based mud-drilling where the water-based mud contains chemical additives. Any sampling and analysis directed by DMM must be by an ELAP-certified laboratory. Disposal must conform to all applicable Department regulations. The pit liner must be ripped and perforated prior to any permitted burial on-site and to the extent practical, excess pit liner material must be removed and disposed of properly. Permission of the surface owner is required for any on-site burial of cuttings and pit liner, regardless of type of drilling and fluids used. Burial of any other trash on-site is specifically prohibited and all such trash must be removed from the site and properly disposed. Transport of all cuttings and pit liner off-site, if required by the Department or otherwise performed, must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit. The *Drilling and Production Waste Tracking Form* must be completed and retained for three years by the generator, transporter and destination facility, and made available to the Department upon request during this period. If requested, the generator is responsible for producing its originating copy of the *Drilling and Production Waste Tracking Form* and the completed form with the original signatures of the generator, transporter and destination facility.

56) A site-specific acid rock drainage (ARD) mitigation plan consistent with the SGEIS must be prepared by the operator and followed for on-site burial of Marcellus Shale cuttings from horizontal drilling in the Marcellus Shale if the operator elects to bury these cuttings. The plan must be available to the Department upon request, and available on-site to a Department inspector while activities addressed by the plan are taking place.

57) The operator must fully implement the Partial Site Reclamation Plan described in the approved application materials.

58) Final reclamation of the wellsite must be approved by the Department. Unless otherwise approved by this office, well pads and access roads constructed for drilling and production operations must be scarified or ripped to alleviate compaction prior to replacement of topsoil.

Reclaimed areas must be seeded and mulched after topsoil replacement. Any proposal by the operator to waive these reclamation requirements must be accompanied by documentation of the landowner's written request to keep the access road and/or well pad.

General

59) The operator must follow applicable best management practices (BMPs) for reducing direct impacts at individual well pads described in Section 7.4.1.1 of the SGEIS.

60) The operator must fully implement the Invasive Species Management Plan described in the approved application materials.

61) The operator must follow applicable best management practices (BMPs) for reducing the potential for transfer and introduction of invasive species described in Section 7.4.2.2 of the SGEIS.

62) The operator must complete the "Record of Formations Penetrated" on the *Well Drilling and Completion Report* providing a log of formations, both unconsolidated and consolidated, and depths and estimated flow rates of any fresh water, brine, oil and/or gas. In accordance with 6 NYCRR 554.7, the well operator must provide the Department with the *Well Drilling and Completion Report* within 30 days after completing the well.

63) Any non-routine incident of potential environmental and/or public safety significance must be verbally reported to the Department within two hours of the incident's known occurrence or discovery, with a written report detailing the non-routine incident to follow within twenty-four hours of the incident's known occurrence or discovery. Non-routine incidents may include, but are not limited to: -casing, drill pipe or hydraulic fracturing equipment failures, cement failures, fishing jobs, fires, seepages, blowouts, surface chemical spills, observed leaks in surface equipment, observed pit liner failure, surface effects at previously plugged or other wells, observed effects at water wells or at the surface, complaints of water well contamination, anomalous pressure and/or flow conditions indicated or occurring during hydraulic fracturing operations, or other potentially polluting non-routine incident or incident that may affect the health, safety, welfare, or property of any person. Provided the environment and public safety would not be further endangered, any action and/or condition known or suspected of causing and/or contributing to a non-routine incident must cease immediately upon known occurrence or discovery of the incident, and appropriate initial remedial actions commenced. The required written non-routine incident report noted above must provide details of the incident and include, as necessary, a proposed remedial plan for Department review and approval. In the case of suspended hydraulic fracturing pumping operations and non-routine incident reporting of such, the operator must receive Department approval prior to recommencing hydraulic fracturing activities in the same well.

64) Flowback water recovered after high-volume hydraulic fracturing operations must be tested for NORM prior to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for NORM prior to removal.

65) Periodic radiation surveys must be conducted at specified time intervals during the production phase for Marcellus wells developed by high-volume hydraulic fracturing completion methods. Such surveys must be performed on all accessible well piping, tanks, or equipment that could contain NORM scale buildup. The surveys must be conducted for as long as the facility remains in active use. If piping, tanks, or equipment is to be removed,

radiation surveys must be performed to ensure their appropriate disposal. All surveys must be conducted in accordance with NYSDOH protocols.

66) Production brine is prohibited from being directed to or stored in any on-site pit. Covered watertight steel, fiberglass or plastic tanks, or covered watertight tanks constructed of another material approved by the Department, are required for production brine handling and containment on the well pad. Production brine tanks, piping and conveyances, including valves, must be constructed of suitable materials, be of sufficient pressure rating and be maintained in a leak-free condition.

67) Production brine which is removed from the site must be disposed, recycled or reused as described by the well permit application materials. Transport of all waste fluids must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit. The *Drilling and Production Waste Tracking Form* must be completed and retained for three years by the generator, transporter and destination facility, and made available to the Department upon request during this period. If requested, the generator is responsible for producing its originating copy of the *Drilling and Production Waste Tracking Form* and the completed form with the original signatures of the generator, transporter and destination facility.

Any deviation from the above conditions must be approved by the Department prior to making a change.

ATTACHMENT A

To avoid or mitigate adverse air quality impacts from the well drilling, completion and production operations, the following restrictions are imposed:

1. The diesel fuel used in drilling and completion equipment engines will be limited to Ultra Low Sulfur Fuel (ULSF) with a maximum sulfur content of 15 ppm.

2. There will not be any simultaneous operations of the drilling and completion equipment engines at the single well pad.

3. The maximum number of wells to be drilled and completed annually or during any consecutive 12--month period at a single pad will be limited to four.

4. The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, then the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control devise to limit the benzene emissions to 1 Tpy.

5. Condensate tanks used at the well pad shall be equipped with vapor recovery systems to minimize fugitive VOC emissions.

6. During the flowback phase, the venting of gas from each well pad will be limited to a maximum of 5 MMscf during any consecutive 12--month period. If "sour" gas is encountered with detected H_2S emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m).

7. During the flowback phase, flaring of gas at each well pad will be limited to a maximum of 120 MMscf during any consecutive 12--month period.

8. Wellhead compressor will be equipped with NSCR controls.

9. No uncertified (i.e., EPA Tier 0) drilling or completion equipment engines will be used for any activity at the well sites.

10. The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both

particulate traps (CRDPF) and SCR controls. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence.

11. The completion equipment engines will be limited to EPA Tier 2 or newer equipment. Particulate traps will be required for all Tier 2 engines. SCR control will be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence.

ATTACHMENT B

PASSBY FLOW IMPLEMENTATION AND ENFORCEMENT

1. Monitoring and Reporting**.** Passby flows must be maintained instantaneously. Determinations of allowable removal rates will be made based on comparisons with instantaneous flow data.

2. Description of Gage Types

Tier I- Gage data in this category is collected by the permitee immediately downstream of the water withdrawal location using streamflow gage equipment capable of accurately measuring instantaneous flow rates as approved at the discretion of the Department.

Tier II- Gage data in this category is obtained from acceptable USGS gages that must be located at a point in the same watershed where the drainage area at the gage is from 0.5x to 2.0x the size of the drainage area as measured at the withdrawal point. The catchment area must not have altered flows unless the instantaneous flow measurements can take into account the alterations.

Tier III- Gage data in this category is obtained from USGS gages that are either outside the acceptable distance within the same watershed or are in adjacent watersheds that possess similar basin characteristics. The use of these "surrogate" watersheds are the most inaccurate account of stream flow and should be used only as approved at the discretion of the Department.

3. All streamflow records used in determining the instantaneous passby flow rates should be measured to the nearest 0.1 cfs at 15-minute increments. Water withdrawal rates must be reported as instantaneous measurements to the nearest 0.1 cfs at 5-minute increments. Reporting is required annually to Department in Microsoft Excel or similar electronic spreadsheet/database formats.

4. Violations and Suspension of Operations. Water withdrawal operations will be suspended immediately upon determination that the required passby flow has not been maintained. The Department has the right to modify passby flow requirements if water quality standards are not being met within a watercourse as the result of a water withdrawal. Failure to submit annual reports, filing of inaccurate reports on water withdrawals, and continuing to withdraw water after a determination that the required passby flow has not been maintained, are all considered separate violations of this permit and the Environmental Conservation Law Article 71-1305(2).

ATTACHMENT C

FOREST AND GRASSLAND FOCUS AREAS

Operators developing well sites in Forest and Grassland Focus Areas that involve disturbance in a contiguous forest patch of 150 acres or more in size or in a contiguous grassland patch of 30 acres or more in size must:

1) Implement mitigation measures identified as part of the Department-approved ecological assessment;

2) Monitor the effects of disturbance as active development proceeds and for a minimum of two years following well completion; and

3) Practice adaptive management as previously unknown effects are documented.

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New York State

DEC

Appendix 11

Analysis of Subsurface Mobility of Fracturing Fluids

Excerpted from ICF International, Task 1, 2009

Revised Draft
Supplemental Generic Environmental Impact Statement

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1.2.4 Principles governing fracturing fluid flow

The mobility of hydraulic fracturing fluid depends on the same physical and chemical principles that dictate all fluid transport phenomena. Frac fluid will flow through the well, the fractures, and the porous media based on pressure differentials and hydraulic conductivities. In addition to the overall flow of the frac fluids, additives may experience greater or lesser movement due to diffusion and adsorption. The concentrations of the fluids and additives may change due to dilution in formation waters and possibly by biological or chemical degradation.

1.2.4.1 Limiting conditions

The analyses below present flow calculations for a range of parameters, with the intent to define reasonable bounds for the conditions likely to be encountered in New York State. Although one or more conditions at some future well sites may lie outside of the ranges analyzed, it is considered unlikely that the combination of conditions at any site would produce environmental impacts that are significantly more adverse than the worst case scenarios analyzed. The equations used in the analyses are presented below to facilitate the assessment of additional scenarios.

The analyses consider potentially useful aquifers with lower limits at depths up to 1,000 feet, somewhat deeper than the maximum aquifer depth reported in Table 3 for the Marcellus Shale. Similarly, the minimum depth to the top of the shale is taken as 2,000 ft, well above the minimum depth reported in Table 3 for the Marcellus Shale. The 2,000 ft. depth has been postulated as the probable upper limit for economic development of the New York shales.

The analyses include an additional conservative assumption. Even for deep aquifers, the analyses consider the pore pressure at the bottom of the aquifer to be zero as if a deep well or well field was operating at maximum drawdown. This assumption maximizes the potential for upward flow of fracturing fluid or its components from the fracture zone to the aquifer.

[134] U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

1.2.4.2 Gradient

For a fracturing fluid or its additives to have a negative impact on a groundwater aquifer, some deleterious component of the fracturing fluid would need to travel from the target fracture zone to the aquifer. In order for fluid to flow from the fracture zone to an aquifer, the *total head*[135] must be greater in the fracture zone than at the well. We can estimate the *gradient*[136] that might exist between a fracture zone in the shale and a potable water aquifer as follows:

$$i = \frac{h_{t1} - h_{t2}}{L} \tag{1}$$

where i = gradient
h_{tn} = total head at Point n
L = length of flow path from Point 1 to Point 2

Since the total head is the sum of the elevation head and the pressure head,

$$h_t = h_e + h_p \tag{2}$$

The gradient can be restated as

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} \tag{3}$$

where h_{en} = elevation head at Point n
h_{pn} = pressure head at Point n

If the ground surface is taken as the elevation datum, we can express the elevation head in terms of depth.

$$d_n = -h_{en} \tag{4}$$

Restating the gradient yields

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} = \frac{(-d_1 + h_{p1}) - (-d_2 + h_{p2})}{L} = \frac{(d_2 - d_1) + (h_{p1} - h_{p2})}{L} \tag{5}$$

where d_n = depth at Point n

We can estimate the maximum likely gradient by considering the combination of parameters which would be most favorable to flow from the hydraulically fractured zone to a potential groundwater aquifer. These include assuming the minimum possible pressure head in the aquifer and the shortest possible flow path, i.e. setting h_{p2} to zero to simulate a well pumped to the maximum aquifer drawdown and setting L to the vertical distance between the fracture zone and the aquifer, $d_1 - d_2$.

[135] Total head at a point is the sum of the elevation at the point plus the pore pressure expressed as the height of a vertical column of water.
[136] The groundwater gradient is the difference in total head between two points divided by the distance between the points.

The gradient now becomes

$$i = \frac{(d_2 - d_1) + h_{p1}}{|d_1 - d_2|} \tag{6}$$

The total vertical stress in the fracture zone equals

$$\sigma_v = d_1 \times \gamma_R \tag{7}$$

where σ_v = total vertical stress
d_1 = depth at Point 1, in the fracture zone
γ_R = average total unit weight of the overlying rock

The effective vertical stress, or the stress transmitted through the mineral matrix, equals the total unit weight minus the pore pressure. For the purposes of this analysis, the pore pressure is taken to be equivalent to that of a vertical water column from the fracture zone to the surface. The effective vertical stress is given by

$$\sigma'_v = \sigma_v - (d_1 \times \gamma_W) \tag{8}$$

where σ'_v = effective vertical stress
γ_W = unit weight of water

The effective horizontal stress and the total horizontal stress therefore equal

$$\sigma'_h = K \times \sigma'_v \tag{9}$$

$$\sigma_h = \sigma'_h + (d_1 \times \gamma_W) \tag{10}$$

where σ'_h = effective horizontal stress
K = ratio of horizontal to vertical stress
σ_h = total horizontal stress

The hydraulic fracturing pressure needs to exceed the minimum total horizontal stress. Allowing for some loss of pressure from the wellbore to the fracture tip, the pressure head in the fracture zone equals

$$h_{p1} = c \times \sigma_h = \frac{c \times d_1 \times [K(\gamma_R - \gamma_W) + \gamma_W]}{\gamma_W} \tag{11}$$

where h_{p1} = pressure head at Point 1, in the fracture zone
c = coefficient to allow for some loss of pressure from the wellbore to the fracture tip

Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of

the geologic materials (estimated at 150 pcf average), times the depth.[137] To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress, yielding

$$h_{p1} = \frac{110\% \times d_1 \times \left[0.75\left(150\,pcf - 62.4\,pcf\right) + 62.4\,pcf\right]}{62.4\,pcf} = 2.26 d_1 \tag{12}$$

Equation (6) thus becomes

$$i = \frac{\left(d_2 - d_1\right) + 2.26 d_1}{\left|d_1 - d_2\right|} = \frac{d_2 + 1.26 d_1}{\left|d_1 - d_2\right|} \tag{13}$$

Figure 1 shows the variation in the average hydraulic gradient between the fracture zone and an overlying aquifer during hydraulic fracturing for a variety of aquifer and shale depths. The gradient has a maximum of about 3.5, and is less than 2.0 for most depth combinations.

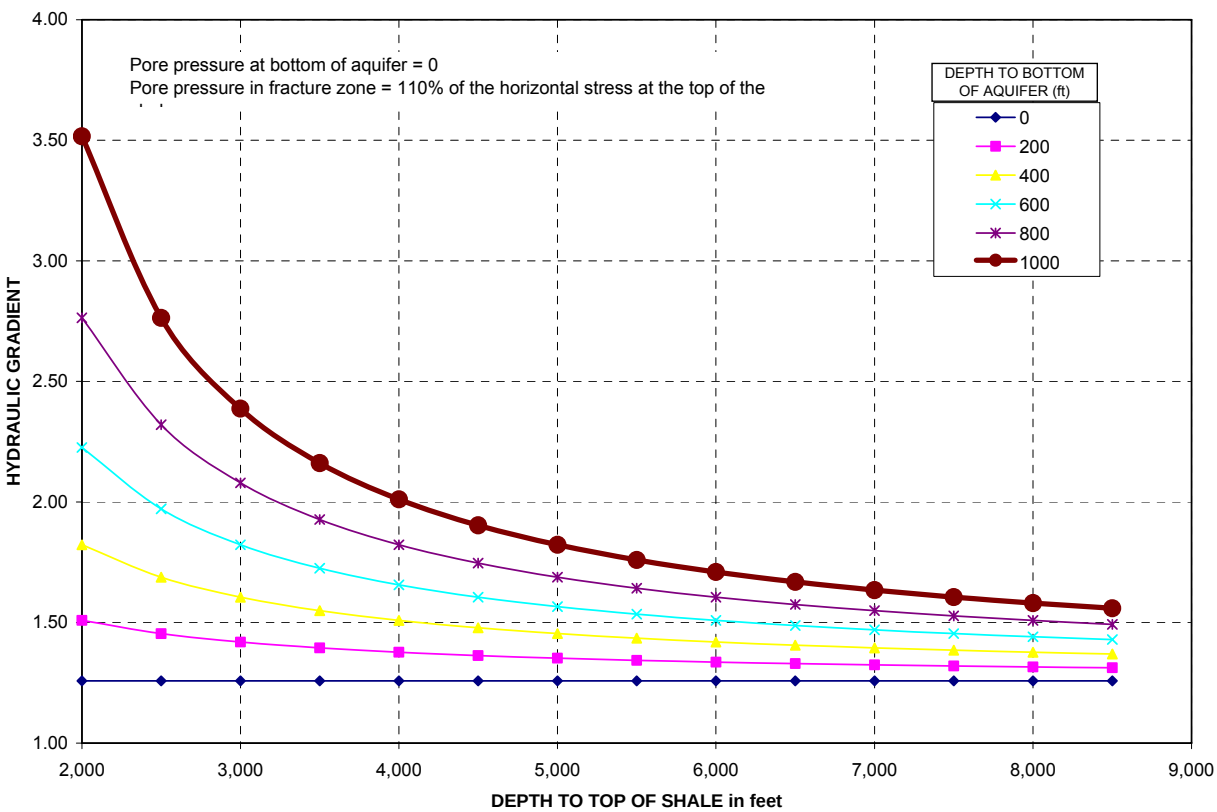

Figure 1: Average hydraulic gradient during fracturing

In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer

[137] Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

to the fracture zone and lower than the average closer to the aquifer. It is important to note that these gradients only apply while fracturing pressures are being applied.

Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer. Evidence suggests that the permeabilities of the Devonian shales are too low for any meaningful hydrological connection with the post-Devonian formations. The high dissolved solid content near 300,000 ppm in pre-Late Devonian formations supports the concept that these formations are hydrologically discontinuous, i.e. not well-connected to other formations.[138] During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow.

1.2.4.3 Seepage velocity

The second aspect to consider with regards to flow is the time required for a particle of fluid to flow from the fracture zone to the well. Using Darcy's law, the seepage velocity would equal

$$v = \frac{ki}{n} \tag{10}$$

where v = seepage velocity
k = hydraulic conductivity
n = porosity

The average hydraulic conductivity between a fracture zone and an aquifer would depend on the hydraulic conductivity of each intervening stratum, which in turn would depend on the type of material and whether it was intact or fractured. The rock types overlying the Marcellus Shale are primarily sandstones and other shales.[139] Table 4 lists the range of hydraulic conductivities for sandstone and shale rock masses. The hydraulic conductivity of rock masses tends to decrease with depth as higher stress levels close or prevent fractures. Vertical flow across a horizontally layered system of geologic strata is controlled primarily by the less permeable strata, so the average vertical hydraulic conductivity of all the strata lying above the target shale would be expected to be no greater than 1E-5 cm/sec and could be substantially lower.

Table 4: Hydraulic conductivity of rock masses[140]

Material	Minimum k	Maximum k
Intact Sandstone	1E-8 cm/sec	1E-5 cm/sec
Sandstone rock mass	1E-9 cm/sec	1E-1 cm/sec
Intact Shale	1E-11 cm/sec	1E-9 cm/sec
Shale rock mass	1E-9 cm/sec	1E-4 cm/sec

Figure 2 shows the seepage velocity from the fracture zone to an overlying aquifer based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the seepage velocity would

[138] Russell, William L., 1972, "Pressure-Depth Relations in Appalachian Region", *AAPG Bulletin*, March 1972, v. 56, No. 3, p. 528-536.
[139] Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.
[140] Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

be lower. For all of the analyses presented in this report, the porosity is taken as 10%, the reported total porosity for the Marcellus Shale.[141] Total porosity equals the contribution from both micro-pores within the intact rock and void space due to fractures. For the overlying strata, the analyses also use the same value for total porosity of 10% which is in the lower range of the typical values for sandstones and shales. This may result in a slight overestimation of the calculated seepage velocity, and an underestimation of the required travel time and available pore storage volume.

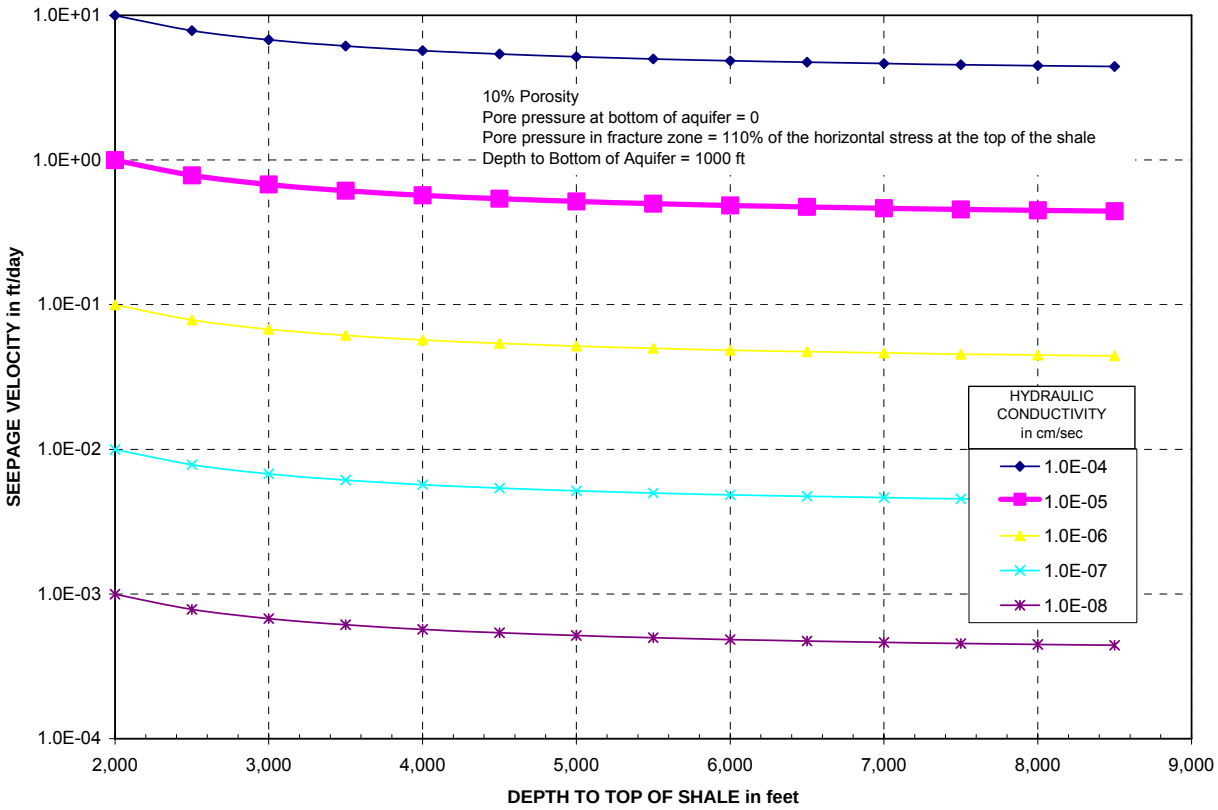

Figure 2: Seepage velocity as a function of hydraulic conductivity

Figure 2 shows that the seepage of hydraulic fracturing fluid would be limited to no more than 10 feet per day, and would be substantially less under most conditions. Since the cumulative amount of time that the fracturing pressure would be applied for all steps of a typical fracture stage is less than one day, the corresponding seepage distance would be similarly limited.

It is important to note that the seepage velocities shown in Figure 2 are based on average gradients between the fracture zone and the overlying aquifer. The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata.

[141] DOE, Office of Fossil Energy, 2009. *State Oil and National Gas Regulations Designed to Protect Water Resources*, May 2009.

1.2.4.4 Required travel time

The time that the fracturing pressure would need to be maintained for the fracturing fluid to flow from the fracture zone to an overlying aquifer is given by

$$t = \frac{|d_2 - d_1|}{v} \tag{11}$$

where t = required travel time

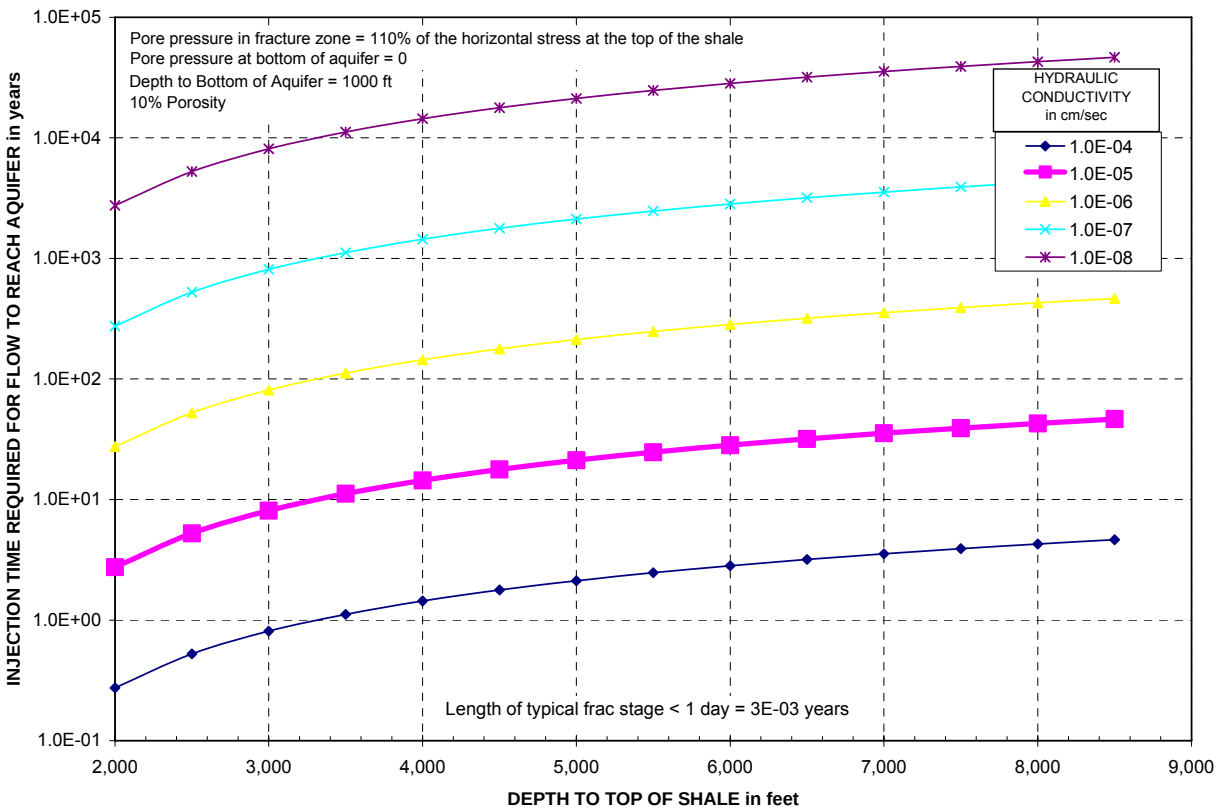

Figure 3: Injection time required for fracture fluid to reach aquifer as a function of hydraulic conductivity

Figure 3 shows the required travel time based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the required flow time would be longer. The required flow times under the fracturing pressure is several orders of magnitude greater than the duration over which the fracturing pressure would be applied.

Figure 4 presents the results of a similar analysis, but with the hydraulic conductivity held at 1E-5 cm/sec and considering various depths to the bottom of the aquifer. Compared to a 1000 ft. deep aquifer, 10 to 20 more years of sustained fracturing pressure would be required for the fracturing fluid to reach an aquifer that was only 200 ft. deep.

The required travel times shown relate to the movement of the groundwater. Dissolved chemicals would move at a slower rate due to retardation. The retardation factor, which is the

ratio of the chemical movement rate compared to the water movement rate, is always between 0.0 and 1.0, so the required travel times for any dissolved chemical would be greater than those shown in Figures 3 and 4.

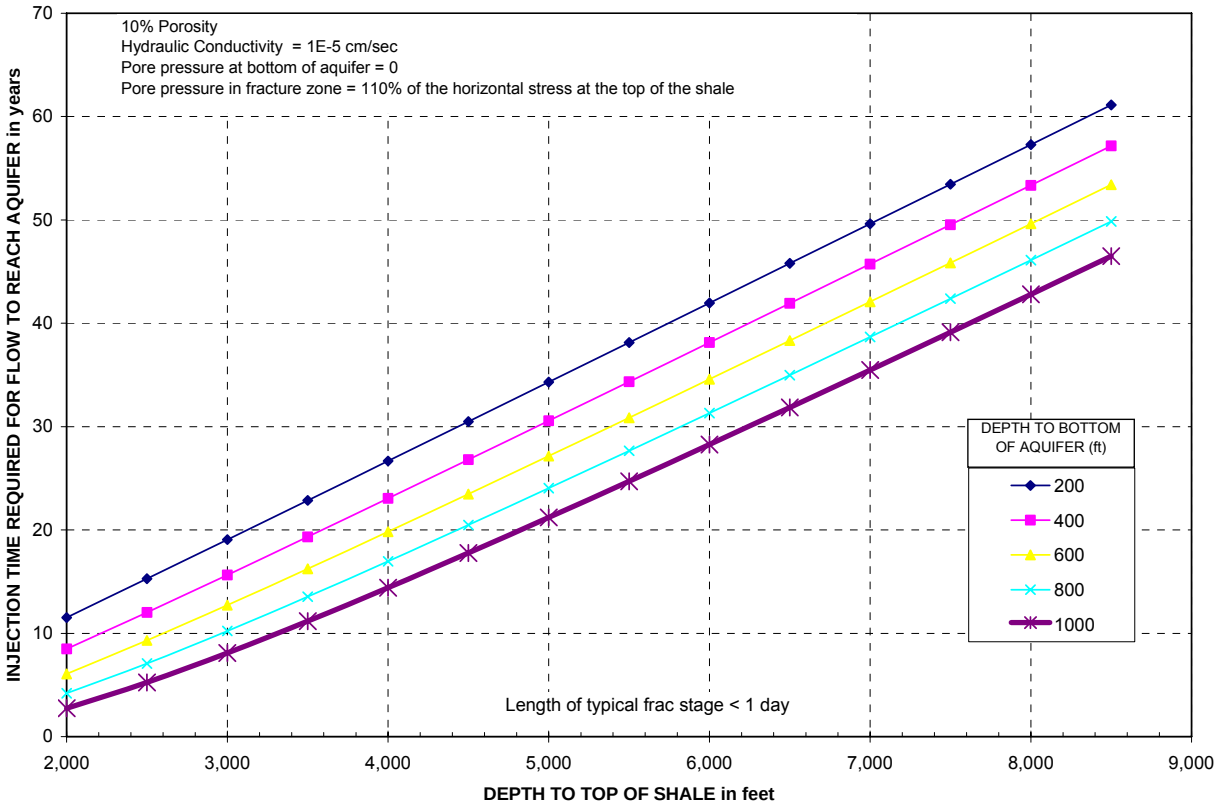

Figure 4: Injection time required for flow to reach aquifer as a function of aquifer depth

1.2.4.5 Pore storage volume

The fourth aspect to consider in evaluating the potential for adverse impacts to overlying aquifers is the volume of fluid injected compared to the volume of the void spaces and fractures that the fluid would need to fill in order to flow from the fracture zone to the aquifer. Figure 5 shows the void volume based on 10% total porosity for the geologic materials for various combinations of depths for the bottom of an aquifer and for the top of the shale, calculated as follows:

$$V = |d_1 - d_2| \times n \times \frac{43{,}560\, ft^2}{acre} \times \frac{7.48 gal}{ft^3} \qquad (12)$$

where V = volume of void spaces and fractures

A typical slickwater fracturing treatment in a horizontal well would use less than 4 million gallons of fracturing fluid, and some portion of this fluid would be recovered as flowback. The void volume, based on 10% total porosity, for the geologic materials between the bottom of an aquifer at 1,000 ft. depth and the top of the shale at a 2,000 ft. depth is greater than 32 million gallons per acre. Since the expected area of a well spacing unit is no less than the equivalent of

40 acres per well,[142,143,144,145] the fracturing fluid could only fill about 0.3% of the overall void space. Alternatively, if the fracturing fluid were to uniformly fill the overall void space, it would be diluted by a factor of over 300. As shown in Figure 5, for shallower aquifers and deeper shales, the void volume per acre is significantly greater.

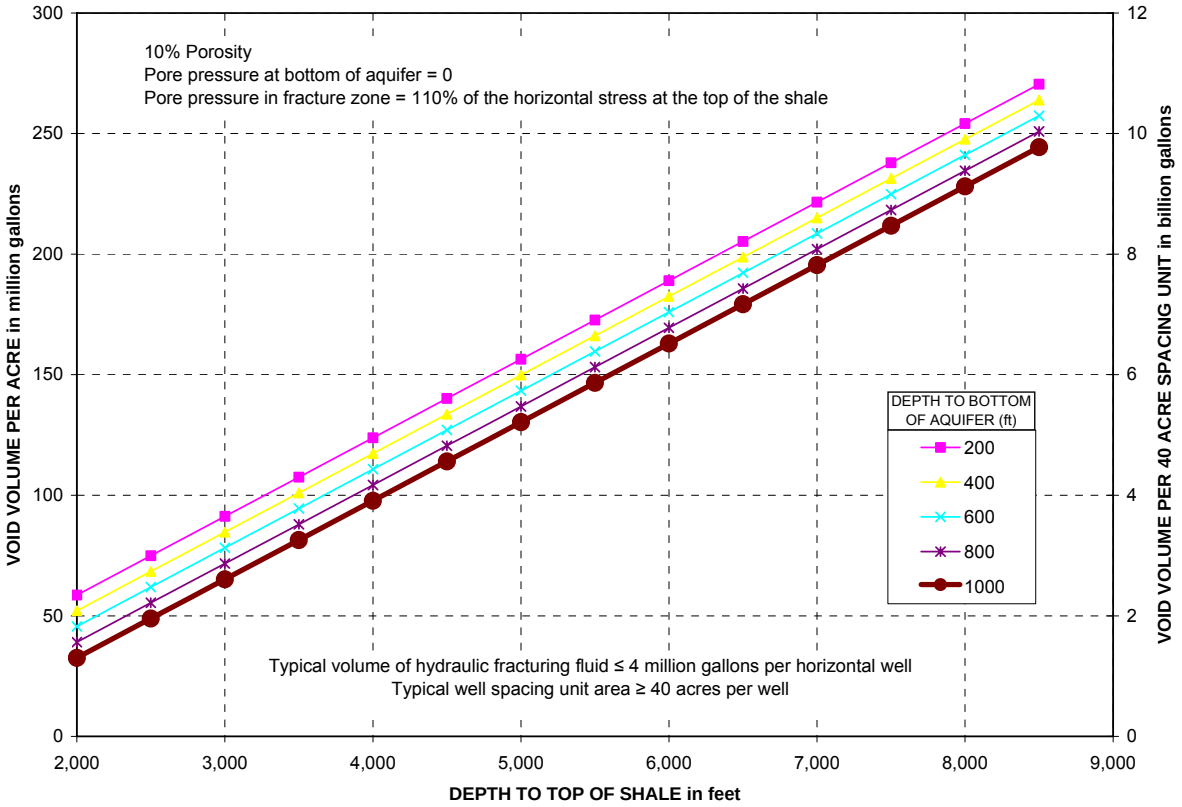

Figure 5: Comparison of void volume to frac fluid volume

1.2.5 Flow through fractures, faults, or unplugged borings

It is theoretically possible but extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer. The open flow path would have a much smaller area of flow leading to the aquifer and the resistance to flow would be lower. In such an improbable case, the flow velocity would be greater, the time required for the fracturing fluid to reach the aquifer would be shorter, and the storage volume between the fracture zone and the aquifer would be less than in the scenarios described above. The probability of such a combination of unlikely conditions occurring simultaneously (deep aquifer, shallow fracture

[142] Infill wells could result in local increases in well density.
[143] New York regulations (Part 553.1 Statewide spacing) require a minimum spacing of 1320 ft. from other oil and gas wells in the same pool. This spacing equals 40 acres per well for wells in a rectangular grid.
[144] New York Codes, Rules, and Regulations, Title 6 Department of Environmental Conservation, Chapter V Resource Management Services, Subchapter B Mineral Resources, 6 NYCRR Part 553.1 Statewide spacing, (as of 5 April 2009).
[145] NYSDEC, 2009, "Final Scope for Draft Supplemental Generic Environmental Impact Statement (dSGEIS) on the Oil, Gas And Solution Mining Regulatory Program, Well Permit Issuance For Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-permeability Gas Reservoirs", February 2009.

zone, and open flow path) is very small. The fracturing contractor would notice an anomaly if these conditions led to the inability to develop or maintain the predicted fracturing pressure.

During flowback, the same conditions would result in a high rate of recapture of the frac fluid from the open flow path, decreasing the potential for any significant adverse environmental impacts. Moreover, during production the gradients along the open flow path would be toward the production zone, flushing any stranded fracturing fluid in the fracture or unplugged wellbore back toward the production well.

1.2.6 Geochemistry

The ability of the chemical constituents of the additives in fracturing fluids to migrate from the fracture zone are influenced not just by the forces governing the flow of groundwater, but also by the properties of the chemicals and their interaction with the subterranean environment. In addition to direct flow to an aquifer, the constituents of fracturing fluid would be affected by limitations on solubility, adsorption and diffusion.

1.2.6.1 Solubility

The solubility of a substance indicates the propensity of the substance to dissolve in a solvent, in this case, groundwater. The substance can continue to dissolve up to its saturation concentration, i.e. its solubility. Substances with high solubilities in water have a higher likelihood of moving with the groundwater flow at high concentrations, whereas substances with low solubilities may act as longer term sources at low level concentrations. The solubilities of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases such as the IUPAC-NIST Solubility Database.[146]

The solubility of a chemical determines the maximum concentration of the chemical that is likely to exist in groundwater. Solubility is temperature dependent, generally increasing with temperature. Since the temperature at the depths of the gas shales is higher than the temperature closer to the surface where a usable aquifer may lie, the solubility in the aquifer will be lower than in the shale formation.

Given the depth of the New York gas shales and the distance between the shales and any overlying aquifer, chemicals with high solubilities would be more likely to reach an aquifer at higher concentrations than chemicals of low solubility. Based on the previously presented fluid flow calculations, the concentrations would be significantly lower than the initial solubilities due to dilution.

1.2.6.2 Adsorption

Adsorption occurs when molecules of a substance bind to the surface of another material. As chemicals pass through porous media or narrow fractures, some of the chemical molecules may adsorb onto the mineral surface. The adsorption will retard the flow of the chemical constituents relative to the rate of fluid flow. The retardation factor, expressed as the ratio of the fluid flow velocity to the chemical movement velocity, generally is higher in fine grained materials and in materials with high organic content. The Marcellus shale is both fine grained and of high organic content, so the expected retardation factors are high. The gray shales overlying the Marcellus

[146] IUPAC-NIST Solubility Database, Version 1.0, NIST Standard Reference Database 106, URL: http://srdata.nist.gov/solubility/index.aspx.

shale would also be expected to substantially retard any upward movement of fracturing chemicals.

The octanol-water partition coefficient, commonly expressed as K_{ow}, is often used in environmental engineering to estimate the adsorption of chemicals to geologic materials, especially those containing organic materials. Chemicals with high partition coefficients are more likely to adsorb onto organic solids and become locked in the shale, and less likely to remain in the dissolve phase than are chemicals with low partition coefficients.

The partition coefficients of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases. The partition coefficient is inversely proportional to solubility, and can be estimated from the following equation[147]

$$\log K_{ow} = -0.862 \log S_w + 0.710 \tag{13}$$

where K_{ow} = octanol-water partition coefficient
S_w = solubility in water at 20ºC in mol/liter

Adsorption in the target black shales or the overlying gray shales would effectively remove some percentage of the chemical mass from the groundwater for long periods of time, although as the concentration in the water decreased some of the adsorbed chemicals could repartition back into the water. The effect of adsorption could be to lower the concentration of dissolved chemicals in any groundwater migrating from the shale formation.

1.2.6.3 Diffusion

Through diffusion, chemicals in fracturing fluids would move from locations with higher concentrations to locations with lower concentrations. Diffusion may cause the transport of chemicals even in the absence of or in a direction opposed to the gradient driving fluid flow. Diffusion is a slow process, but may continue for a very long time. As diffusion occurs, the concentration necessarily decreases. If all diffusion were to occur in an upward direction (an unlikely, worst-case scenario) from the fracture zone to an overlying freshwater aquifer, the diffused chemical would be dispersed within the intervening void volume and be diluted by at least an average factor of 160 based on the calculated pore volumes in Section 1.2.4.5. Since a concentration gradient would exist from the fracture zone to the aquifer, the concentration at the aquifer would be significantly lower than the calculated average. Increased vertical distance between the aquifer and the fracture zone due to shallower aquifers and deeper shales would further increase the dilution and reduce the concentration reaching the aquifer.

1.2.6.4 Chemical interactions

Mixtures of chemicals in a geologic formation will behave differently than pure chemicals analyzed in a laboratory environment, so any estimates based on the solubility, adsorption, or diffusion properties of individual chemicals or chemical compounds should only be used as a guide to how they might behave when injected with other additives into the shale. Co-solubilities can change the migration properties of the chemicals and chemical reactions can create new compounds.

[147] Chiou, Cary T., *Partition and adsorption of organic contaminants in environmental systems*, John Wiley & Sons, New York, 2002, p.57.

1.2.7 Conclusions

Analyses of flow conditions during hydraulic fracturing of New York shales help explain why hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers. Specific conditions or analytical results supporting this conclusion include:

- The developable shale formations are separated from potential freshwater aquifers by at least 1,000 feet of sandstones and shales of moderate to low permeability.
- The fracturing pressures which could potentially drive fluid from the target shale formation toward the aquifer are applied for short periods of time, typically less than one day per stage, while the required travel time for fluid to flow from the shale to the aquifer under those pressures is measured in years.
- The volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer.
- Some of the chemicals in the additives used in hydraulic fracturing fluids would be adsorbed by and bound to the organic-rich shales.
- Diffusion of the chemicals throughout the pore volume between the shale and an aquifer would dilute the concentrations of the chemicals by several orders of magnitude.
- Any flow of frac fluid toward an aquifer through open fractures or an unplugged wellbore would be reversed during flowback, with any residual fluid further flushed by flow toward the production zone as pressures decline in the reservoir during production.

The historical experience of hydraulic fracturing in tens of thousands of wells is consistent with the analytical conclusion. There are no known incidents of groundwater contamination due to hydraulic fracturing.

New York State

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Appendix 12

Beneficial Use Determination (BUD) Notification Regarding Road Spreading

Revised Draft
Supplemental Generic Environmental Impact Statement

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New York State Department of Environmental Conservation
Division of Solid and Hazardous Materials
Bureau of Solid Waste, Reduction and Recycling, 9th Floor
625 Broadway, Albany, New York 12233-7253
Phone: (518) 402-8704 • **FAX:** (518) 402-9024
Website: www.dec.ny.gov

Alexander B. Grannis
Commissioner

January 2009

NOTICE TO GAS AND OIL WELL & LPG STORAGE FLUID HAULERS

All gas or oil well drilling and production fluids including but not limited to brine and fracturing fluids, and brine from liquefied petroleum gas (LPG) well storage operations, transported for disposal, road spreading, reuse in another gas or oil well, or recycling must be specifically identified in Part C and D of the New York State Waste Transporter Permit Application Form. Transporters must identify the type of fluid proposed to be transported in Section C in the Non-Hazardous Industrial/Commercial box and the Disposal or Destination Facility (or Use) in Part D.

Fracture fluids obtained during flowback operations may not be spread on roads and must be disposed at facilities authorized by the Department. Such disposal facilities must be identified in Part D of the permit application. If fluids are to be transported for use or reuse at another gas or oil well, that location must be identified in Part D of the permit application.

With respect to fluids transported under a Waste Transporter Permit, only production brines or brine from LPG storage operations may be used for road spreading. Drilling, fracing, and plugging fluids are not acceptable for road spreading.

Any person, including any government entity, applying for a Part 364 permit or permit modification to use production brine from oil or gas wells or brine from LPG well storage operations for road spreading purposes (i.e. road de-icing, dust suppression, or road stabilization) must submit a petition for a beneficial use determination (BUD). If a contract hauler is applying for a Part 364 permit or permit modification to deliver brine to a government agency for road spreading purposes, that government agency must submit the BUD petition. The BUD must be granted and the Part 364 permit/modification must be issued before brine can be removed from the well or LPG storage site for road spreading purposes or storage at an offsite facility.

The BUD petition must include:

1. An original letter signed and dated by the government agency representative or other property owner authorizing the use of brine on the locations identified in below item 3.

2. The name, address and telephone number of the person, company or government official seeking the approval.

3. An identification (or map) of the specific roads or other areas that are to receive the brine and any brine storage locations, excluding the well site storage locations.

4. The physical address of the brine storage locations from which the brine is hauled.

5. For each well field or LPG storage facility, a chemical analysis of a representative sample of the brine performed by a NYSDOH approved laboratory for the following parameters: calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil & grease, benzene, ethylbenzene, toluene, and xylene. Depending upon the analytical results, the Department may require additional analyses. (This analysis is not required for brine from a LPG well operation with a valid New York State SPDES permit.)

6. A road spreading plan that includes a description of the procedures to prevent the brine from flowing or running off into streams, creeks, lakes and other bodies of water. The plan should include:

- a description of how the brine will be applied, including the equipment to be used and the method for controlling the rate of application. In general this should indicate that the brine is applied by use of a spreader bar or similar spray device with shut-off controls in the cab of the truck; and with vehicular equipment that is dedicated to this use or cleaned of previously transported waste materials prior to this use;
- the proposed rate and frequency of application;
- a description of application restrictions. For dust control and road stabilization use this description should indicate that the brine is not applied: after daylight hours; within 50 feet of a stream, creek, lake or other body of water; on sections of road having a grade exceeding 10 percent; or on wet roads, during rain, or when rain is imminent. For road deicing use, this description should indicate that the brine is applied in accordance NYSDOT Guidelines for Anit-Icing with Liquids and include any other restrictions.

7. Where applicable, a brine storage plan that includes:

- a description of the type, material, size, and number of storage tanks and the maximum anticipated storage;
- procedures for run off and run-on control;
- provisions for secondary containment; and
- a contingency plan.

If you have any questions concerning your permit, please feel free to call this office at (518) 402-8707. You may also visit our public website at the address above for information and forms to download or print.

Waste Transporter Permit Program

New York State

DEC

Appendix 13

Radiological Data - Production Brine from NYS Marcellus Wells

Revised Draft
Supplemental Generic Environmental Impact Statement

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NYS Marcellus Radiological Data from Production Brine

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Maxwell 1C	31-101-22963-03-01	10/7/2008	Caton (Steuben)	Gross Alpha	17,940 +/- 8,634 pCi/L
				Gross Beta	4,765 +/- 3,829 pCi/L
				Cesium-137	-2.26 +/- 5.09 pCi/L
				Cobalt-60	-0.748 +/- 4.46 pCi/L
				Ruthenium-106	9.27 +/- 46.8 pCi/L
				Zirconium-95	37.8 +/- 21.4 pCi/L
				Radium-226	2,472 +/- 484 pCi/L
				Radium-228	874 +/- 174 pCi/L
				Thorium-228	53.778 +/- 8.084 pCi/L
				Thorium-230	0.359 +/- 0.221 pCi/L
				Thorium-232	0.065 +/- 0.103 pCi/L
				Uranium-234	0.383 +/- 0.349 pCi/L
				Uranium-235	0.077 +/- 0.168 pCi/L
				Uranium-238	0.077 +/- 0.151 pCi/L
Frost 2	31-097-23856-00-00	10/8/2008	Orange (Schuyler)	Gross Alpha	14,530 +/-3,792 pCi/L
				Gross Beta	4,561 +/- 1,634 pCi/L
				Cesium-137	2.54 +/- 4.64 pCi/L
				Cobalt-60	-1.36 +/- 3.59 pCi/L
				Ruthenium-106	-9.03 +/- 36.3 pCi/L
				Zirconium-95	31.6 +/- 14.6 pCi/L
				Radium-226	2,647 +/- 494 pCi/L
				Radium-228	782 +/- 157 pCi/L
				Thorium-228	47.855 +/- 9.140 pCi/L
				Thorium-230	0.859 +/- 0.587 pCi/L
				Thorium-232	0.286 +/- 0.328 pCi/L
				Uranium-234	0.770 +/- 0.600 pCi/L
				Uranium-235	0.113 +/- 0.222 pCi/L
				Uranium-238	0.431 +/- 0.449 pCi/L
Webster T1	31-097-23831-00-00	10/8/2008	Orange (Schuyler)	Gross Alpha	123,000 +/- 23,480 pCi/L
				Gross Beta	12,000 +/- 2,903 pCi/L
				Cesium-137	1.32 +/- 5.76 pCi/L
				Cobalt-60	-2.42 +/- 4.76 pCi/L
				Ruthenium-106	-18.3 +/- 44.6 pCi/L
				Zirconium-95	34.5 +/- 15.6 pCi/L
				Radium-226	16,030 +/- 2,995 pCi/L
				Radium-228	912 +/- 177 pCi/L
				Thorium-228	63.603 +/- 9.415 pCi/L
				Thorium-230	0.783 +/- 0.286 pCi/L
				Thorium-232	0.444 +/- 0.213 pCi/L
				Uranium-234	0.232 +/- 0.301 pCi/L
				Uranium-235	0.160 +/- 0.245 pCi/L
				Uranium-238	-0.016 +/- 0.015 pCi/L

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Calabro T1	31-097-23836-00-00	3/26/2009	Orange (Schuyler)	Gross Alpha	18,330 +/- 3,694 pCi/L
				Gross Beta	-324.533 +/- 654 pCi/L
				Cesium-137	3.14 +/- 7.19 pCi/L
				Cobalt-60	0.016 +/- 5.87 pCi/L
				Ruthenium-106	17.0 +/- 51.9 pCi/L
				Zirconium-95	24.2 +/- 13.6 pCi/L
				Radium-226	13,510 +/- 2,655 pCi/L
				Radium-228	929 +/- 179 pCi/L
				Thorium-228	45.0 +/- 8.41 pCi/L
				Thorium-230	2.80 +/- 1.44 pCi/L
				Thorium-232	-0.147 +/- 0.645 pCi/L
				Uranium-234	1.91 +/- 1.82 pCi/L
				Uranium-235	0.337 +/- 0.962 pCi/L
				Uranium-238	0.765 +/- 1.07 pCi/L
Maxwell 1C	31-101-22963-03-01	4/1/2009	Caton (Steuben)	Gross Alpha	3,968 +/- 1,102 pCi/L
				Gross Beta	618 +/- 599 pCi/L
				Cesium-137	-0.443 +/- 3.61 pCi/L
				Cobalt-60	-1.840 +/- 2.81 pCi/L
				Ruthenium-106	17.1 +/- 29.4 pCi/L
				Zirconium-95	26.4 +/- 8.38 pCi/L
				Radium-226	7,885 +/- 1,568 pCi/L
				Radium-228	234 +/- 50.5 pCi/L
				Thorium-228	147 +/- 23.2 pCi/L
				Thorium-230	1.37 +/- 0.918 pCi/L
				Thorium-232	0.305 +/- 0.425 pCi/L
				Uranium-234	1.40 +/- 1.25 pCi/L
				Uranium-235	0.254 +/- 0.499 pCi/L
				Uranium-238	0.508 +/- 0.708 pCi/L
Haines 1	31-101-14872-00-00	4/1/2009	Avoca (Steuben)	Gross Alpha	54.6 +/- 37.4 pCi/L
				Gross Beta	59.3 +/- 58.4 pCi/L
				Cesium-137	0.476 +/- 2.19 pCi/L
				Cobalt-60	-0.166 +/- 2.28 pCi/L
				Ruthenium-106	7.15 +/- 19.8 pCi/L
				Zirconium-95	0.982 +/- 4.32 pCi/L
				Radium-226	0.195 +/- 0.162 pCi/L
				Radium-228	0.428 +/- 0.335 pCi/L
				Thorium-228	0.051 +/- 0.036 pCi/L
				Thorium-230	0.028 +/- 0.019 pCi/L
				Thorium-232	0.000 +/- 0.007 pCi/L
				Uranium-234	0.000 +/- 0.014 pCi/L
				Uranium-235	0.000 +/- 0.005 pCi/L
				Uranium-238	-0.007 +/- 0.006 pCi/L

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Haines 2	31-101-16167-00-00	4/1/2009	Avoca (Steuben)	Gross Alpha	70.0 +/- 47.8 pCi/L
				Gross Beta	6.79 +/- 54.4 pCi/L
				Cesium-137	2.21 +/- 1.64 pCi/L
				Cobalt-60	1.42 +/- 2.83 pCi/L
				Ruthenium-106	5.77 +/- 15.2 pCi/L
				Zirconium-95	2.43 +/- 3.25 pCi/L
				Radium-226	0.163 +/- 0.198 pCi/L
				Radium-228	0.0286 +/- 0.220 pCi/L
				Thorium-228	0.048 +/- 0.038 pCi/L
				Thorium-230	0.040 +/- 0.022 pCi/L
				Thorium-232	-0.006 +/- 0.011 pCi/L
				Uranium-234	0.006 +/- 0.019 pCi/L
				Uranium-235	0.006 +/- 0.013 pCi/L
				Uranium-238	-0.013 +/- 0.009 pCi/L
Carpenter 1	31-101-26014-00-00	4/1/2009	Troupsburg (Steuben)	Gross Alpha	7,974 +/- 1,800 pCi/L
				Gross Beta	1,627 +/- 736 pCi/L
				Cesium-137	2.26 +/- 4.97 pCi/L
				Cobalt-60	-0.500 +/- 3.84 pCi/L
				Ruthenium-106	49.3 +/- 38.1 pCi/L
				Zirconium-95	30.4 +/- 11.0 pCi/L
				Radium-226	5,352 +/- 1,051 pCi/L
				Radium-228	138 +/- 37.3 pCi/L
				Thorium-228	94.1 +/- 14.9 pCi/L
				Thorium-230	1.80 +/- 0.946 pCi/L
				Thorium-232	0.240 +/- 0.472 pCi/L
				Uranium-234	0.000 +/- 0.005 pCi/L
				Uranium-235	0.000 +/- 0.005 pCi/L
				Uranium-238	-0.184 +/- 0.257 pCi/L
Zinck 1	31-101-26015-00-00	4/1/2009	Woodhull (Steuben)	Gross Alpha	9,426 +/- 2,065 pCi/L
				Gross Beta	2,780 +/- 879 pCi/L
				Cesium-137	5.47 +/- 5.66 pCi/L
				Cobalt-60	0.547 +/- 4.40 pCi/L
				Ruthenium-106	-16.600 +/- 42.8 pCi/L
				Zirconium-95	48.0 +/- 15.1 pCi/L
				Radium-226	4,049 +/- 807 pCi/L
				Radium-228	826 +/- 160 pCi/L
				Thorium-228	89.1 +/- 14.7 pCi/L
				Thorium-230	0.880 +/- 1.23 pCi/L
				Thorium-232	0.000 +/- 0.705 pCi/L
				Uranium-234	-0.813 +/- 0.881 pCi/L
				Uranium-235	-0.325 +/- 0.323 pCi/L
				Uranium-238	-0.488 +/- 0.816 pCi/L

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Schiavone 2	31-097-23226-00-01	4/6/2009	Reading (Schuyler)	Gross Alpha	16,550 +/- 3,355 pCi/L
				Gross Beta	1,323 +/- 711 pCi/L
				Cesium-137	1.46 +/- 5.67 pCi/L
				Cobalt-60	-2.550 +/- 5.11 pCi/L
				Ruthenium-106	20.6 +/- 42.7 pCi/L
				Zirconium-95	30.6 +/- 12.1 pCi/L
				Radium-226	15,140 +/- 2,989 pCi/L
				Radium-228	957 +/- 181 pCi/L
				Thorium-228	38.7 +/- 7.45 pCi/L
				Thorium-230	1.68 +/- 1.19 pCi/L
				Thorium-232	0.153 +/- 0.301 pCi/L
				Uranium-234	3.82 +/- 2.48 pCi/L
				Uranium-235	0.354 +/- 0.779 pCi/L
				Uranium-238	0.354 +/- 0.923 pCi/L
Parker 1	31-017-26117-00-00	4/2/2009	Oxford (Chenango)	Gross Alpha	3,914 +/- 813 pCi/L
				Gross Beta	715 +/- 202 pCi/L
				Cesium-137	4.12 +/- 3.29 pCi/L
				Cobalt-60	-1.320 +/- 2.80 pCi/L
				Ruthenium-106	-9.520 +/- 24.5 pCi/L
				Zirconium-95	1.39 +/- 6.35 pCi/L
				Radium-226	1,779 +/- 343 pCi/L
				Radium-228	201 +/- 38.9 pCi/L
				Thorium-228	15.4 +/- 3.75 pCi/L
				Thorium-230	1.25 +/- 0.835 pCi/L
				Thorium-232	0.000 +/- 0.385 pCi/L
				Uranium-234	1.82 +/- 1.58 pCi/L
				Uranium-235	0.304 +/- 0.732 pCi/L
				Uranium-238	0.304 +/- 0.732 pCi/L
WGI 10	31-097-23930-00-00	4/6/2009	Dix (Schuyler)	Gross Alpha	10,970 +/- 2,363 pCi/L
				Gross Beta	1,170 +/- 701 pCi/L
				Cesium-137	1.27 +/- 5.17 pCi/L
				Cobalt-60	0.960 +/- 4.49 pCi/L
				Ruthenium-106	14.5 +/- 37.5 pCi/L
				Zirconium-95	15.2 +/- 8.66 pCi/L
				Radium-226	6,125 +/- 1,225 pCi/L
				Radium-228	516 +/- 99.1 pCi/L
				Thorium-228	130 +/- 20.4 pCi/L
				Thorium-230	2.63 +/- 1.39 pCi/L
				Thorium-232	0.444 +/- 0.213 pCi/L
				Uranium-234	0.000 +/- 0.702 pCi/L
				Uranium-235	1.17 +/- 1.39 pCi/L
				Uranium-238	0.389 +/- 1.01 pCi/L

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
WGI 11	31-097-23949-00-00	4/6/2009	Dix (Schuyler)	Gross Alpha	20,750 +/- 4,117 pCi/L
				Gross Beta	2,389 +/- 861 pCi/L
				Cesium-137	4.78 +/- 6.95 pCi/L
				Cobalt-60	-0.919 +/- 5.79 pCi/L
				Ruthenium-106	-19.700 +/- 49.8 pCi/L
				Zirconium-95	9.53 +/- 11.8 pCi/L
				Radium-226	10,160 +/- 2,026 pCi/L
				Radium-228	1,252 +/- 237 pCi/L
				Thorium-228	47.5 +/- 8.64 pCi/L
				Thorium-230	1.55 +/- 1.16 pCi/L
				Thorium-232	-0.141 +/- 0.278 pCi/L
				Uranium-234	0.493 +/- 0.874 pCi/L
				Uranium-235	0.000 +/- 0.540 pCi/L
				Uranium-238	-0.123 +/- 0.172 pCi/L

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New York State

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Appendix 14

Department of Public Service Environmental Management & Construction Standards and Practices – Pipelines

Revised Draft
Supplemental Generic Environmental Impact Statement

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ENVIRONMENTAL MANAGEMENT AND CONSTRUCTION

STANDARDS AND PRACTICES

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New York State

DEC

Appendix 15

Hydraulic Fracturing – 15 Statements from Regulatory Officials

Revised Draft
Supplemental Generic Environmental Impact Statement

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Part A

GWPC's Congressional Testimony

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STATEMENT OF
SCOTT KELL
ON BEHALF OF THE
GROUND WATER PROTECTION COUNCIL

HOUSE COMMITTEE ON NATURAL RESOURCES
SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES
WASHINGTON, D.C.
JUNE 4, 2009

Mr. Chairman, thank you for the opportunity to testify today. My name is Scott Kell. I am President of the Ground Water Protection Council (GWPC) and appear here today on its behalf. I am also Deputy Chief of the Ohio Department of Natural Resources Division of Mineral Resources Management. With me today are Mike Paque, Executive Director of the GWPC, Dave Bolin, Assistant Director of the Alabama Oil and Gas Board, and Lori Wrotenbery, Director of the Oklahoma Corporation Commission's Oil and Gas Conservation Division. Within our respective States, we are responsible for implementing the state regulations governing the exploration and development of oil and natural gas resources. First and foremost, we are resource protection professionals committed to stewardship of water resources in the exercise of our authority.

The GWPC is a non-profit association of state agencies responsible for environmental safeguards related to ground water. The members of the association consist of state ground water and underground injection control regulators. The GWPC provides a forum through which its state members work with federal scientists and regulators, environmental groups, industry, and other stakeholders to advance protection of ground water resources through development of policy and regulation that is based on sound science. I have included a list of the GWPC Board of Directors in our written submission.

The GWPC understands that our nation's water and energy needs are intertwined, and that demand for both resources is increasing. Smart energy policy will consider and minimize impacts to water resources.

With respect to the protection of water resources, the GWPC recently published two reports of note. The first of these reports is called *Modern Shale Gas Development in the United States: A Primer (http://www.gwpc.org/e-library/documents/general/Shale%20Gas%20Primer%202009.pdf)*. The primer discusses the regulatory framework, policy issues, and technical aspects of developing unconventional shale gas resources. As you know, there are numerous deep shale gas basins in the United States, which contain trillions of cubic feet of natural gas. The environmentally responsible development of these resources is of critical importance to the energy security of the U.S. Recently, however, there has been concern raised about the methods used to tap these valuable resources. Technologies such as

hydraulic fracturing have been characterized as being environmentally risky and inadequately regulated. The primer is designed to provide accurate technical information to assist policy makers in their understanding of these issues.

In recent months, the states have become aware of press reports and websites alleging that six states have documented over one thousand incidents of ground water contamination resulting from the practice of hydraulic fracturing. Such reports are not accurate. Attached to my testimony are signed statements from state officials representing Ohio, Pennsylvania, New Mexico, Alabama, and Texas, responding to these allegations.

From the standpoint of the GWPC, the most critical issue is protection of water resources. As such, our goal is to ensure that oil and gas development is managed in a way that does not create unnecessary and unwarranted risks to water. As a state regulatory official, I can assure you that our regulations are focused on this task. This leads me to the second report the GWPC has recently published.

This report, entitled *State Oil and Gas Regulations Designed to Protect Water Resources,* (http://www.gwpc.org/e-library/documents/general/Oil%20and%20Gas%20Regulation%20Report%20Final%20with%20Cover%205-27-2009.pdf) evaluates regulations implemented by state oil and gas regulatory agencies as they relate to the protection of water. To prepare this report, the GWPC reviewed the regulations of the twenty-seven states that, when combined, account for more than 99.8% of all the oil and natural gas extracted in the U.S. annually. To prepare this report, each state's regulatory requirements were studied with respect to their water protection capacity. The study evaluated regulated processes such as well drilling, construction, and plugging, above-ground storage tanks, pits and a number of other topics. The report also contains a statistical analysis of state regulations. As a result of our regulatory review and analysis, the GWPC concluded that state oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, hydraulic fracturing, waste handling, and well plugging requirements. While State regulations are generally adequate, the GWPC report makes the following recommendations.

First, a study of effective hydraulic fracturing practices should be considered for the purpose of developing Best Management Practices (BMPs) that can be adjusted to fit the specific conditions of individual states. A one-size-fits-all federal program is not the most effective way to regulate in this area. BMPs related to hydraulic fracturing would assist states and operators in ensuring the safety of the practice. Of special concern are zones in close proximity to underground sources of drinking water, as determined by the state regulatory authority.

Second, the state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time. This process should be expanded, where appropriate, to include state oil and gas programmatic

elements not covered by the current state review guidelines. STRONGER is currently convening a stakeholder workgroup to consider drafting guidelines for state regulation of hydraulic fracturing.

Finally, the GWPC concludes that implementation and advancement of electronic data management systems has enhanced state regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental, or water related data. States should continue to develop comprehensive electronic data management systems and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

In conclusion, Mr. Chairman and Committee Members, we believe that state regulations are designed to provide the level of water protection needed to assure water resources remain both viable and available. The states are continuously striving to improve both the regulatory language and the programmatic tools used to implement that language. In this regard, the GWPC will continue to assist states with their regulatory needs for the purpose of protecting water, our most vital natural resource.

Thank you.

DISCLOSURE REQUIREMENT
Required by House Rule XI, clause 2(g)
and Rules of the Committee on Resources

1. Name: **Scott R. Kell**

2. Business Address: **2045 Morse Rd., Columbus, OH 43229-6605**

3. Business Phone Number: **614-265-7058**

4. Organization you are representing: **The Ground Water Protection Council**

5. Any training or educational certificates, diplomas or degrees or other educational experiences which add to your qualifications to testify on or knowledge of the subject matter of the hearing: **Bachelor's Degree in Geology from Mount Union College and a Masters Degree in Geology from Kent State University.**

6. Any professional licenses, certifications, or affiliations held which are relevant to your qualifications to testify on or knowledge of the subject matter of the hearing:

7. Any employment, occupation, ownership in a firm or business, or work-related experiences which relate to your qualifications to testify on or knowledge of the subject matter of the hearing:

8. Any offices, elected positions, or representational capacity held in the organization on whose behalf you are testifying: **Chief of the Ohio Department of Natural Resources, Division of Mineral Resources Management; President of the Ground Water Protection Council**

9. Any federal grants or contracts (including subgrants or subcontracts) from the Department of the Interior (and /or other agencies invited) which **you** have received in the last three years, including the source and the amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

10. Any federal grants or contracts (including subgrants or subcontracts) the Department of the Interior (and /or other agencies invited) which were received in the last three years by the **organization(s) which you represent** at this hearing, including the source and amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

11. Any other information you wish to convey which might aid the members of the Committee to better understand the context of your testimony:

GWPC Board of Directors

Sarah Pillsbury
New Hampshire Department Of Environmental Services
95 Hazen Drive
Concord, NH 03302

John T. Barndt
Delaware Dept Of Natural Resources
& Environmental Control
89 Kings Highway
Dover, DE 19901

Joseph J. Lee, P.G.
Pennsylvania Dept. Of Environmental Protection
Bureau Of Watershed Management
P.O. Box 8555
Harrisburg, PA 17015-8555

David Bolin
Alabama State Oil and Gas Board
P.O. Box 869999
Tuscaloosa, AL 35486-6999

Scott R. Kell
Ohio Department Of Natural Resources
2045 Morse Rd.
Columbus, OH 43229-6605

Jon L. Craig
Oklahoma Department Of Environmental Quality
707 N. Robinson, 8th Floor
Oklahoma City, OK 73102

Marty L. Link
Nebraska Department Of Environmental Quality
P.O. Box 98922
Lincoln, NE 68509-8922

Kevin Frederick, P.G.
Wyoming Dept. of Environmental Quality
DEQ/WQD
122 W. 25th ST. - 4W
Cheyenne, WY 82002

John Norman
Alaska Oil and Gas Conservation Commission
333 West 7th Avenue, Suite 100
Anchorage, AK 99501-3935

Peter T Goodmann
Kentucky Division of Water
14 Reilly Road
Frankfort, KY 40601

David Terry
Massachusetts Dept Of Environmental Protection
One Winter Street, 6th Floor
Boston, MA 02108

Bradley J. Field
New York Dept. Of Environmental Conservation
Division Of Mineral Resources
625 Broadway
Albany, NY 12233-6500

James Martin
West Virginia Dept. Of Environmental Protection
Office Of Oil & Gas
601 57th Street, SE
Charleston, WV 25304

Jamie L. Crawford
Mississippi Dept. Of Environmental Quality
Office Of Land and Water Resources
P.O. Box 2309
Jackson, MS 39225

Michael Lemcke
Wisconsin Department Of Natural Resources
P.O. Box 7921
Madison, WI 53707

Leslie Savage
Texas Railroad Commission
1701 N. Congress
P.O. Box 12967, Capitol Station
Austin, TX 78711-2967

Stan Belieu
Nebraska Oil and Gas Conservation Commission
922 Illinois Street, P.O. Box 399
Sidney, NE 69162

Tom Richmond
Montana Board of Oil & Gas Conservation
2535 St. John's Avenue
Billings, MT 59102

Harold P. Bopp
California Department Of Conservation
Div Of Oil, Gas, and Geothermal Resources
801 K Street, MS 20-20
Sacramento, CA 95814-3530

Mike Paque, Executive Director
The Ground Water Protection Council
13308 N. MacArthur Boulevard
Oklahoma City, OK 73142

Attachment 1 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009

State Oil and Natural Gas Regulations Designed to Protect Water Resources

EXECUTIVE SUMMARY

Over the past several years the GWPC has been asked, "Do state oil and gas regulations protect water?" How do their rules apply? Are they adequate? The first step in answering these questions is to evaluate the regulatory frameworks within which programs operate. That is the purpose of this report.

State regulation of oil and natural gas exploration and production activities are approved under state laws that typically include a prohibition against causing harm to the environment. This premise is at the heart of the regulatory process. The regulation of oil and gas field activities is managed best at the state level where regional and local conditions are understood and where regulations can be tailored to fit the needs of the local environment. Hence, the experience, knowledge and information necessary to regulate effectively most commonly rests with state regulatory agencies. Many state agencies use programmatic tools and documents to apply state laws including regulations, formal and informal guidance, field rules, and Best Management Practices (BMPs). They are also equipped to conduct field inspections, enforcement/oversight, and witnessing of specific operations like well construction, testing and plugging.

Regulations alone cannot convey the full measure of a regulatory program. To gain a more complete understanding of how regulatory programs actually function, one has to evaluate the use of state guides, manuals, environmental policy processes, environmental impact statements, requirements established by permit and many other practices. However, that is not the purpose of this study. This study evaluates the language of state oil and gas regulations as they relate to the direct protection of water resources. It is not an evaluation of state programs.

To conduct the study, state oil and gas regulations were reviewed in the following areas: 1) permitting, 2) well construction, 3) hydraulic fracturing, 4) temporary abandonment, 5) well plugging, 6) tanks, 7) pits, and 8) waste handling and spills. Within each area specific sub-areas were included to broaden the scope of this review. For example, in the area of pits, a review was conducted of sub-areas such as pit liners, siting, construction, use, duration and closure. The selection of the twenty-seven states for this study was based upon the last full-year list (2007) of producing states compiled by the U.S. Energy Information Administration.

In the area of well construction, state regulations were evaluated to determine whether the setting of surface casing below ground water zones was required, whether cement circulation on surface casing was also required, and whether the state utilized recognized cement standards. Attachment 3 is a listing of the programmatic areas and sub-areas reviewed.

After evaluation, each state was given the opportunity to review and comment on the findings and to provide updated information concerning their regulations. Thirteen states responded. These responses were incorporated into the study.

One of the most important accomplishments of the study was the development of a regulations reference document (Addendum). This document contains excerpted language from each state's oil and gas regulations related to the programmatic areas included in the study. Hyperlinks to web versions of each

state's oil and gas regulations are included as well as some of the forms used by state agencies to implement those regulations. A web enabled version of the study (to be completed by September, 2009) will also contain numerous hyperlinked text segments designed to provide the reader with an easy and effective way to review references and regulations.

Key Messages and Suggested Actions:

Key Message 1: State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.

Suggested Action 1: States should review current regulations in several programmatic areas to determine whether or not they meet an appropriate level of specificity (e.g. use of standard cements, plugging materials, pit liners, siting criteria, and tank construction standards etc…)

Key Message 2: Experience suggests that state oil and gas regulations related to well construction are designed to be protective of ground water resources relative to the potential effects of hydraulic fracturing. However, development of Best Management Practices (BMPs) related to hydraulic fracturing would assist states and operators in insuring continued safety of the practice; especially as it relates to hydraulic fracturing of zones in close proximity to ground water, as determined by the regulatory authority.

Suggested Action 2: A study of effective hydraulic fracturing practices should be considered for the purpose of developing (BMPs); which can be adjusted to fit the specific conditions of individual states.

Key Message 3: Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.

Suggested Action 3: States with split jurisdiction of programs should insure that formal memorandums of agreement (MOAs) between agencies exist and that these MOAs are maintained to provide more effective and efficient implementation of regulations.

Key Message 4: The state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time.

Suggested Action 4: The state review process should be continued and, where appropriate, expanded to include state oil and gas programmatic elements not covered by the current state review guidelines.

Key Message 5: The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental data.

Suggested Action 5: States should continue to develop and install comprehensive electronic data management systems, convert paper records to electronic formats and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

Attachment 2 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009

Modern Shale Gas Development in the United States: A Primer

EXECUTIVE SUMMARY

Natural gas production from hydrocarbon rich shale formations, known as "shale gas," is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total. The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

The United States has abundant natural gas resources. The Energy Information Administration estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place). Technically recoverable unconventional gas (shale gas, tight sands, and coalbed methane) accounts for 60% of the onshore recoverable resource. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years. Separate estimates of the shale gas resource extend this supply to 116 years.

Natural gas use is distributed across several sectors of the economy. It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come.

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 States. Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs. The total recoverable gas resources in four new shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. This potential for production in the

known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook.

Shale gas is present across much of the lower 48 States. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies.

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of fluids from shale gas activities. The Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight).

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-sizefits-all regulation at the federal level. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas

development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature. Shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well economics. Horizontal drilling provides more exposure to a formation than does a vertical well. This increase in reservoir exposure creates a number of advantages over vertical wells drilling. Six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure into a shale formation to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the shale to the well in economic quantities. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. For shale gas development, fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

The amount of water needed to drill and fracture a horizontal shale gas well generally ranges from about 2 million to 4 million gallons, depending on the basin and formation characteristics. While these volumes may seem very large, they are small by comparison to some other uses of water, such as agriculture, electric power generation, and municipalities, and generally represent a small percentage of the total water resource use in each shale gas area. Calculations indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin. Because the development of shale gas is new in some areas, these water needs may still challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies, state agencies, and regional water basin commissions can help operators and communities to coexist and effectively manage local water resources. One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region.

After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces

future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water for reuse in a variety of applications. This allows shale gas-associated produced water to be viewed as a potential resource in its own right.

Some soils and geologic formations contain low levels of naturally occurring radioactive material (NORM). When NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

Because the general public does not come into contact with gas field equipment for extended periods, there is very little exposure risk from gas field NORM. To protect gas field workers, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard gas field waste. Conversely, if NORM concentrations are above regulatory limits, the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure.

Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities. Emissions may include NO_x, volatile organic compounds, particulate matter, SO_2, and methane. EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

The primary differences between modern shale gas development and conventional natural gas development are the extensive uses of horizontal drilling and high-volume hydraulic fracturing. The use of horizontal drilling has not introduced any new environmental concerns. In fact, the reduced number of horizontal wells needed coupled with the ability to drill multiple wells from a single pad has significantly reduced surface disturbances and associated impacts to wildlife, dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources, and interference with existing businesses. Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proved to be an effective stimulation technique. While some challenges exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected. Taken together, state and federal requirements along with the technologies and practices developed by industry serve to reduce environmental impacts from shale gas operations.

Ohio Department of Natural Resources

TED STRICKLAND, GOVERNOR | SEAN D. LOGAN, DIRECTOR

John F. Husted, Chief
Division of Mineral Resources Management
2045 Morse Road, Building H-3
Columbus, OH 43229-6693
Phone: (614) 265-6633 Fax: (614) 265-7999

May 27, 2009

Mike Paque
Executive Director
Ground Water Protection Council
13309 North MacArthur Boulevard
Oklahoma City, Oklahoma 73142

Dear Mike:

In recent months, the Ohio Department of Natural Resources, Division of Mineral Resources Management (DMRM) has become aware of website and media releases reporting that the State of Ohio has documented cases of ground water contamination caused by the standard industry practice of hydraulic fracturing. Such reports are not accurate. For example, some articles inaccurately portrayed hydraulic fracturing as the cause of a natural gas incident in Bainbridge Township of Geauga County that resulted in an in-home explosion in December 2007. This portrayal is not consistent with the findings or conclusions of the DMRM.

DMRM completed a thorough investigation into the cause of a natural gas invasion into fresh water aquifers in Bainbridge Township. The DMRM investigation found that this incident was caused by a defective primary cement job on the production casing, which was further complicated by operator error. As a consequence of this finding, the operator corrected the construction problem by completing remedial cementing operations. The findings and conclusions of this investigation are available on the web at http://www.dnr.state.oh.us/bainbridge/tabid/20484/default.aspx.

While an explosion significantly damaged one house, the investigation did not find any evidence to support the claim "that pressure caused by hydraulic fracturing pushed the gas...through a system of cracks into the ground water aquifer" as reported by some media accounts. In actuality, the team of geologists who completed the evaluation of the gas invasion incident in Bainbridge Township concluded that the problem would have occurred even if the well had never been stimulated by hydraulic fracturing.

After 25 years of investigating citizen complaints of contamination, DMRM geologists have not documented a single incident involving contamination of ground water attributed to hydraulic fracturing. Over this time, the Ohio DMRM has consistently taken decisive action to address oil and gas exploration and production practices that have caused documented incidents of ground water contamination. The DMRM has initiated amendments to statutes and rules, designed permit conditions, refined standards

operating procedures, and developed best management practices to improve protection of ground water resources. These actions resulted in substantive changes including:

1. elimination of tens of thousands of earthen pits for produced water storage;
2. development of a model Class II brine injection well program;
3. development of technical standards for synthetic liners used in pits during drilling operations;
4. tighter standards for construction and mechanical integrity testing for annular disposal wells;
5. detailed plugging regulations; and,
6. establishment of an orphaned well plugging program funded by a severance tax on oil and gas production.

The Ohio DMRM will continue to assign the highest priority to improving protection of water resources and public health and safety.

In conclusion, the Ohio DMRM has not identified hydraulic fracturing as a significant threat to ground water resources.

Sincerely,

Scott R. Kell, Deputy Chief

SRK/csc

Enclosure

cc: Cathryn Loucas, Deputy Director, ODNR
Mike Shelton, Chief, Legislative Services, ODNR
John Husted, Chief, DMRM

Pennsylvania Department of Environmental Protection

Rachel Carson State Office Building
P.O. Box 8555
Harrisburg, PA 17105-8555
June 1, 2009

Bureau of Watershed Management 717-772-4048

Michael Paque, Executive Director
Ground Water Protection Council
13308 North MacArthur Boulevard
Oklahoma City, OK 73142

Dear Mr. Paque:

I am the program manager for Pennsylvania's Ground Water Protection Program in the Pennsylvania Department of Environmental Protection (DEP). I have been concerned about press reports stating extensive groundwater pollution and contamination of underground sources of drinking water in Pennsylvania, as a result of hydraulic fracturing to stimulate gas production from deep, gas bearing rock formations. DEP has not concluded that the activity of hydraulic fracturing of these formations has caused wide-spread groundwater contamination.

After review of DEP's complaint database and interviews with regional staff that investigate groundwater contamination related to oil and gas activities, no groundwater pollution or disruption of underground sources of drinking water has been attributed to hydraulic fracturing of deep gas formations. All investigated cases that have found pollution, which are less then 80 in over 15 years of records, have been primarily related to physical drilling through the aquifers, improper design or setting of upper and middle well casings, or operator negligence.

If you have any questions or concerns, you may contact me by e-mail at josless@state.pa.us or by telephone at 717-772-4048.

Sincerely,

Joseph J. Lee, Jr., P.G., chief
Source Protection Section
Division of Water Use Planning

New Mexico Energy, Minerals and Natural Resources Department

Mark Fesmire
Division Director
Oil Conservation Division

May 29, 2009

Mr. Michael Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mike:

As per your request, I have reviewed the New Mexico Oil Conservation Division Data concerning water contamination caused by Hydraulic Fracturing in New Mexico.

While we do currently list approximately 421 ground water contamination cases caused by pits and approximately an equal number caused by other contamination mechanisms, we have found no example of contamination of usable water where the cause was claimed to be hydraulic fracturing.

Sincerely,

Mark E. Fesmire, PE
Director, New Mexico Oil Conservation Division

Oil Conservation Division
1220 South St. Francis Drive • Santa Fe, New Mexico 87505
Phone (505) 476-3440 • Fax (505) 476-3462 • www.emnrd.state.nm.us/OCD

STATE OIL AND GAS BOARD OF ALABAMA

OIL AND GAS BOARD
James H. Griggs, Chairman
Charles E. (Ward) Pearson, Vice Chairman
Rebecca Wright Pritchett, Member
Berry H. (Nick) Tew, Jr., Secretary
S. Marvin Rogers, Counsel

420 Hackberry Lane
P.O. Box 869999
Tuscaloosa, Alabama 35486-6999
Phone (205)349-2852
Fax (205)349-2861
www.ogb.state.al.us

Berry H. (Nick) Tew, Jr.
Oil and Gas Supervisor

May 27, 2009

Mr. Michel Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mr. Paque:

This letter is in response to your recent inquiry regarding any cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in Alabama. I can state with authority that there have been no documented cases of drinking water contamination caused by such hydraulic fracturing operations in our State.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that being to protect underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, to include the regulation and approval of hydraulic fracturing operations, have been actively implemented continually since the Board was established in 1945, pursuant to its legislative mandates.

The point to be made here is that the State of Alabama has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect those sources from all oil and gas operations. The fact that there has been no documented case of contamination from these operations, to include hydraulic fracturing, is a testament to the proactive regulation of the industry by the Board. Additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

If we can be of further assistance in this matter, please let me know.

Sincerely,

David E. Bolin

David E. Bolin
Deputy Director

RAILROAD COMMISSION OF TEXAS

CHAIRMAN VICTOR G. CARRILLO

May 29, 2009

Mike Paque, Executive Director
Ground Water Protection Agency
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Re: Hydraulic Fracturing of Gas Wells in Texas

Dear Mr. Paque:

I am pleased that representatives of the Ground Water Protection Council will be appearing before the U.S. House Committee on Natural Resources next week on the issue of hydraulic fracturing. I was asked to participate but had a longstanding commitment to tour energy projects in Canada that prevented me from personally participating.

I sincerely hope that you will clear up the misconception that there are "thousands" of contamination cases in Texas and other states resulting from hydraulic fracturing. The Railroad Commission of Texas is the chief regulatory agency over oil and gas activities in this state. Though hydraulic fracturing has been used for over 50 years in Texas, our records do not indicate a single documented contamination case associated with hydraulic fracturing.

The Texas Groundwater Protection Committee (TGPC) tracks groundwater pollution in Texas. All Texas water protection agencies, including the Railroad Commission, are members. Each year, the TGPC publishes a Joint Groundwater Monitoring and Contamination Report, which can be found at http://www.tceq.state.tx.us/comm_exec/forms_pubs/pubs/sfr/056_07_index.html. The 2007 report cites a total of 354 active groundwater cases attributed to oil and gas activity – this in a state with over 255,000 active oil and gas wells. The majority of these cases are associated with previous practices that are no longer allowed, or result from activity now prohibited by our existing regulations. A few cases were due to blowouts that primarily occur during drilling activity. *Not one of these cases was caused by hydraulic fracturing activity.*

Hydraulic fracturing plays a key role in the development of virtually all unconventional gas resources in Texas. As of this year, over 11,000 gas wells have been completed (and hydraulically fractured) in the Barnett Shale reservoir, one of the nation's most active and largest natural gas fields. Since 2000, over five trillion cubic feet of gas has been produced from this one reservoir and the Barnett Shale production currently contributes over 20% of Texas' total natural gas production. While the volume of gas-in-place in the Barnett Shale is estimated to be over 27 trillion cubic feet, recovery of the gas is difficult because of the shale's low permeability. The remarkable success of the Barnett Shale results in large part from the use of horizontal drilling coupled with hydraulic fracturing. Even with this intense activity, there are no known instances of ongoing groundwater contamination in the Barnett Shale play.

P.O. Box 12967 ★ Austin, Texas 78711-2967 ★ Phone (512) 463-7131 ★ Fax (512) 463-7161

Regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states. Most oil and gas producing state have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – harming domestic energy security. I urge the U.S. Congress to leave the regulatory authority over hydraulic fraturing and other oil and gas activities where it belongs – at the state level.

Sincerely,

Victor G. Carrillo, Chairman
Railroad Commission of Texas

cc: Commissioner Michael Williams
Commissioner Elizabeth Ames Jones
John J. Tintera, Executive Director

Part B

IOGCC's Statements from Oil & Gas Regulators from 12 Member States

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REGULATORY STATEMENTS ON HYDRAULIC FRACTURING
SUBMITTED BY THE STATES
JUNE 2009

The following statements were issued by state regulators for the record related to hydraulic fracturing in their states. Statements have been compiled for this document.

ALABAMA:

Nick Tew, Ph.D., P.G.
Alabama State Geologist & Oil and Gas Supervisor
President, Association of American State Geologists

There have been no documented cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in the State of Alabama.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board of Alabama's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that is, the protection of underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, which include the regulation and approval of hydraulic fracturing operations, have been continuously and actively implemented since the Board was established in 1945, pursuant to its mission and legislative mandates.

The State of Alabama, acting through the Board, has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect these sources from all oil and gas operations, including hydraulic fracturing. The fact that there has been no documented case of contamination from these operations, including hydraulic fracturing, is strong evidence of effective regulation of the industry by the Board. In our view, additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

ALASKA:

Cathy Foerster
Commissioner
Alaska Oil and Gas Conservation Commission

There have been no verified cases of harm to ground water in the State of Alaska as a result of hydraulic fracturing.

State regulations already exist in Alaska to protect fresh water sources. Current well construction standards used in Alaska (as required by Alaska Oil and Gas Conservation Commission statutes

and regulations) properly protect fresh drinking waters. Surface casing is always set well below fresh waters and cemented to surface. This includes both injectors and producers as the casing/cementing programs are essentially the same in both types of wells. There are additional casings installed in wells as well as tubing which ultimately connects the reservoir to the surface. The AOGCC requires rigorous testing to demonstrate the effectiveness of these barriers protecting fresh water sources.

By passing this legislation [FRAC Act] it is probable that every oil and gas well within the State of Alaska will come under EPA jurisdiction. EPA will then likely set redundant construction guidelines and testing standards that will merely create duplicate reporting and testing requirements with no benefit to the environment. Additional government employees will be required to monitor the programs, causing further waste of taxpayer dollars.

Material safety data sheets for all materials used in oil and gas operations are required to be maintained on location by Hazard Communication Standards of OSHA. Therefore, requiring such data in the FRAC bill is, again, merely duplicate effort with and accomplishes nothing new.

COLORADO:

David Neslin
Director
Colorado Oil and Gas Conservation Commission

To the knowledge of the Colorado Oil and Gas Conservation Commission staff, there has been no verified instance of harm to groundwater caused by hydraulic fracturing in Colorado.

INDIANA:

Herschel McDivitt
Director
Indiana Department of Natural Resources

There have been no instances where the Division of Oil and Gas has verified that harm to groundwater has ever been found to be the result of hydraulic fracturing in Indiana. In fact, we are unaware of any allegations that hydraulic fracturing may be the cause of or may have been a contributing factor to an adverse impact to groundwater in Indiana.

The Division of Oil and Gas is the sole agency responsible for overseeing all aspects of oil and gas production operations as directed under Indiana's Oil and Gas Act. Additionally, the Division of Oil and Gas has been granted primacy by the U.S. Environmental Protection Agency, to implement the Underground Injection Control (UIC) Program for Class II wells in Indiana under the Safe Drinking Water Act.

KENTUCKY:

Kim Collings, EEC
Director
Kentucky Division of Oil and Gas

In Kentucky, there have been alleged contaminations from citizen complaints but nothing that can be substantiated, in every case the well had surface casing cemented to surface and production casing cemented.

LOUISIANA:

James Welsh
Commissioner of Conservation
Louisiana Department of Natural Resources

The Louisiana Office of Conservation is unaware of any instance of harm to groundwater in the State of Louisiana caused by the practice of hydraulic fracturing. My office is statutorily responsible for regulation of the oil and gas industry in Louisiana, including completion technology such as hydraulic fracturing, underground injection and disposal of oilfield waste operations, and management of the major aquifers in the State of Louisiana.

MICHIGAN:

Harold Fitch
Director, Office of Geological Survey
Department of Environmental Quality

My agency, the Office of Geological Survey (OGS) of the Department of Environmental Quality, regulates oil and gas exploration and production in Michigan. The OGS issues permits for oil and gas wells and monitors all aspects of well drilling, completion, production, and plugging operations, including hydraulic fracturing.

Hydraulic fracturing has been utilized extensively for many years in Michigan, in both deep formations and in the relatively shallow Antrim Shale formation. There are about 9,900 Antrim wells in Michigan producing natural gas at depths of 500 to 2000 feet. Hydraulic fracturing has been used in virtually every Antrim well.

There is no indication that hydraulic fracturing has ever caused damage to ground water or other resources in Michigan. In fact, the OGS has never received a complaint or allegation that hydraulic fracturing has impacted groundwater in any way.

OKLAHOMA:

Lori Wrotenbery
Director, Oil and Gas Conservation Division
Oklahoma Corporation Commission

You asked whether there has been a verified instance of harm to groundwater in our state from the practice of hydraulic fracturing. The answer in no. We have no documentation of such an instance. Furthermore, I have consulted the senior staffs of our Pollution Abatement Department, Field Operations Department, and Technical Services Department, and they have no recollection of having ever received a report, complaint, or allegation of such an instance. We also contacted the senior staffs of the Oklahoma Department of Environmental Quality, who likewise, have no such knowledge or information.

While there have been incidents of groundwater contamination associated with oil and gas drilling and production operations in the State of Oklahoma, none of the documented incidents have been associated with hydraulic fracturing. Our agency has been regulating oil and gas drilling and production operations in the state for over 90 years. Tens of thousands of hydraulic fracturing operations have been conducted in the state in the last 60 years. Had hydraulic fracturing caused harm to groundwater in our state in anything other than a rare and isolated instance, we are confident that we would have identified that harm in the course of our surveillance of drilling and production practices and our investigation of groundwater contamination incidents.

TENNESSEE:

Paul Schmierbach
Manager
Tennessee Department of Environmental Conservation

We have had no reports of well damage due to fracking.

TEXAS:

Victor G. Carrillo
Chairman
Railroad Commission of Texas

The practice of reservoir stimulation by hydraulic fracturing has been used safely in Texas for over six decades in tens of thousands of wells across the state.

Recently in his introductory Statement for the Record (June 9, 2009) of the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, Senator Robert Casey stated:

> "Now, the oil and gas industry would have you believe that there is no threat to drinking water from hydraulic fracturing. But the fact is we are already seeing cases in Pennsylvania, Colorado, Virginia, West Virginia, Alabama, Wyoming, Ohio, Arkansas, Utah, Texas, and New Mexico where residents have become ill or groundwater has become contaminated after hydraulic fracturing operations began in the area."

This statement perpetuates the misconception that there are many surface or groundwater contamination cases in Texas and other states due to hydraulic fracturing. This is not true and here are the facts: Though hydraulic fracturing has been used for over 60 years in Texas, our Railroad Commission records ***do not reflect a single documented surface or groundwater contamination case associated with hydraulic fracturing***.

Hydraulic fracturing plays a key role in the development of unconventional gas resources in Texas. As of this year, over 11,000 gas wells have been completed - and hydraulically fractured - in the Newark East (Barnett Shale) Field, one of the nation's largest and most active natural gas fields. Since 2000, over 5 Tcf (trillion cubic feet) of gas has been produced from this one reservoir and Barnett Shale production currently contributes over 20% of total Texas natural gas production (over 7 Tcf in 2008 – more than a third of total U.S. marketed production). While the volume of gas-in-place in the Barnett Shale is estimated to be over 27 Tcf, conventional recovery of the gas is difficult because of the shale's low permeability. The remarkable success of the Barnett Shale results in large part from the use of horizontal drilling coupled with hydraulic fracturing. Even with this intense activity, there are no known instances of ongoing surface or groundwater contamination in the Barnett Shale play.

Regulating oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states, which have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – substantially harming domestic energy security. Congress should maintain the status quo and let the states continue to responsibly regulate oil and gas activities, including hydraulic fracturing.

In summary, I am aware of no verified instance of harm to groundwater in Texas from the decades long practice of hydraulic fracturing.

SOUTH DAKOTA:

Fred Steece
Oil and Gas Supervisor
Department of Environment and Natural Resource

Oil and gas wells have been hydraulically fractured, "fracked," in South Dakota since oil was discovered in 1954 and since gas was discovered in 1970. South Dakota has had rules in place, dating back to the 1940's, that require sufficient surface casing and cement to be installed in

wells to protect ground water supplies in the state's oil fields. Producing wells are required to have production casing and cement, and tubing with packers installed. The casing, tubing, and cement are all designed to protect drinking waters of the state as well as to prevent commingling of water and oil and gas in the subsurface. In the 41 years that I have supervised oil and gas exploration, production and development in South Dakota, no documented case of water well or aquifer damage by the fracking of oil or gas wells, has been brought to my attention. Nor am I aware of any such cases before my time.

WYOMING:

Rick Marvel
Engineering Manager
Wyoming Oil and Gas Conservation Commission

Tom Doll
Oil and Gas Commission Supervisor
Wyoming Oil and Gas Conservation Commission

- No documented cases of groundwater contamination from fracture stimulations in Wyoming.

- No documented cases of groundwater contamination from UIC regulated wells in Wyoming.

- Wyoming took primacy over UIC Class II wells in 1982, currently 4,920 Class II wells permitted.

Wyoming's 2008 activity:

- Powder River Basin Coalbed Wells – 1,699 new wells, no fracture stimulation.
- Rawlins Area (deeper) Coalbed Wells – 109 new wells, 100% fracture stimulated.
- Statewide Conventional Gas Wells – 1,316 new wells, 100% fracture stimulated – many wells with multi-zone fracture stimulations in each well bore, some staged and some individual fracture stimulations.
- Statewide Oil Wells – 237 new wells, 75% fracture stimulated.

The Wyoming Oil and Gas Commission Rules and Regulations are specific in requiring the operator receive approval prior to performing hydraulic fracturing treatments. The Rules require the operator to provide detailed information regarding the hydraulic fracturing process, to include the source of water and/or trade name fluids, type of proponents, as well as estimated pump pressures. After the treatment is complete the operator is required to provide actual fracturing data in detail and resulting production results.

Under Chapter 3, Section 8 (c) The Application for Permit to Drill or Deepen (Form 1) states…"information shall also be given relative to the drilling plan, together with any other information which may be required by the Supervisor. Where multiple Applications for Permit

to Drill will be sought for several wells proposed to be drilled to the same zone within an area of geologic similarity, approval may be sought from the Supervisor to file a comprehensive drilling plan containing the information required above which will then be referenced on each Application for Permit to Drill." Operators have been informed by Commission staff to include detailed information regarding the hydraulic fraction stimulation process on the Form 1 Application for Permit to Drill.

The Rules also state, in Chapter 3, Section 1 (a) "A written notice of intention to do work or to change plans previously approved on the original APD and/or drilling and completion plan (Chapter 3, Section 8 (c)) must be filed with the Supervisor on the Sundry Notice (Form 4), unless otherwise directed, and must reach the Supervisor and receive his approval before the work is begun. Approval must be sought to acidize, cleanout, flush, fracture, or stimulate a well. The Sundry Notice must include depth to perforations or the openhole interval, the source of water and/or trade name fluids, type proponents, as well as estimated pump pressures. Routine activities that do not affect the integrity of the wellbore or the reservoir, such as pump replacements, do not require a Sundry Notice. The Supervisor may require additional information." Most operators will submit the Sundry Notice Form 4 to provide the specific detail for the hydraulic fracturing treatment even though the general information might have been provided under the Form 1 Application for Permit to Drill.

After the hydraulic fracture treatment is complete, results must be reported to the Supervisor. Chapter 3, Section 12 Well Completion or Recompletion Report and Log (Form 3) state "upon completion or recompletion of a well, stratigraphic test or core hole, or the completion of any remedial work such as plugging back or drilling deeper, acidizing, shooting, formation fracturing, squeezing operations, setting a liner, gun perforating, or other similar operations not specifically covered herein, a report on the operation shall be filed with the Supervisor. Such report shall present a detailed account of the work done and the manner in which such work was performed; the daily production of the oil, gas, and water both prior to and after the operation; the size and depth of perforations; the quantity of sand, crude, chemical, or other materials employed in the operation and any other pertinent information of operations which affect the original status of the well and are not specifically covered herein."

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New York State

DEC

Appendix 16

Applicability of NO_x RACT Requirements for Natural Gas Production Facilities

Revised Draft
Supplemental Generic Environmental Impact Statement

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Applicability of NO_x RACT Requirements for Natural Gas Production Facilities

New York State's air regulation 6 NYCRR Part 227-2, Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x), applies to boilers (furnaces) and internal combustion engines at major sources.

The requirements of Part 227-2 include emission limits, stack testing, and annual tune-ups, among others. Many facilities whose potential to emit (PTE) air pollutants would make them susceptible to NO_x RACT requirements can limit, or "cap", their emissions using the limits within the New York State Department of Environmental Conservation's (DEC) Air Emissions Permits applicability thresholds to avoid this regulation.

New York State has two different major source thresholds for NO_x RACT and permitting. Downstate (in New York City and Nassau, Suffolk, Westchester, Rockland, and Lower Orange Counties) the major source permitting and NO_x RACT requirements apply to facilities with a PTE of 25 tons/yr or more of NO_x. For the rest of the state (where the majority of natural gas production facilities are anticipated to be located), the threshold is a PTE of 100 tons/yr or more of NO_x.

If the stationary engines at a natural gas production facility exceed the applicability levels or if the PTE at the facility would classify it as a Major NO_x source, the following compliance options are available:

1. Develop a NO_x RACT compliance plan and apply for a Title V permit.

2. Limit the facility's emissions to remain under the NO_x RACT applicability levels by applying for one of two New York State Air Emissions permits, depending on how low emissions can be limited.

The permitting options for facilities that wish to limit, or "cap", their emissions by establishing appropriate permit conditions are described below.

New York State's air regulation 6 NYCRR Part 201, Permits and Registrations, includes a provision that allows a facility to register if its actual emissions are less than 50% of the applicability thresholds
(less than 12.5 tons/yr downstate and less than 50 tons/yr upstate). This permit option is known as "cap by rule" registration.

Part 201 also includes a provision that allows a facility to limit its emissions by obtaining a State Facility Permit, if its actual emissions are above the 50% level but below the applicability level (between 12.5 and 25 tons/yr downstate and between 50 and 100 tons/yr upstate).

If the facility NO_x emissions cannot be capped below the applicability levels, then the facility should immediately develop a NO_x RACT compliance plan. This plan should contain the necessary steps (purchase of equipment and controls, installation of equipment, source testing, submittal of permit application, etc.) and projected completion dates required to bring the facility into compliance. This plan is to be submitted to the appropriate DEC Regional Office as soon as possible. In this case the facility would also be subject to Title V, and a Title V air permit application must be prepared and submitted.

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New York State

DEC

Appendix 17

Applicability of 40 CFR Part 63 Subpart ZZZZ (Engine MACT) for Natural Gas Production Facilities – Final Rule

Updated July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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Applicability of 40 CFR Part 63 Subpart ZZZZ (Engine MACT)
for Natural Gas Production Facilities – Final Rule

EPA published a final rule on August 20, 2010 revising 40 CFR Part 63, Subpart ZZZZ, in order to address hazardous air pollutant (HAP) emissions from existing stationary reciprocating internal combustion engines (RICE) located at area sources. A major source of HAP emissions is a stationary source that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year. An area source of HAP emissions is a source that is not a major source.

Available emissions data show that several HAP, which are formed during the combustion process or which are contained within the fuel burned, are emitted from stationary engines. The HAP which have been measured in emission tests conducted on natural gas fired and diesel fired RICE include: 1,1,2,2-tetrachloroethane, 1,3-butadiene, 2,2,4-trimethylpentane, acetaldehyde, acrolein, benzene, chlorobenzene, chloroethane, ethylbenzene, formaldehyde, methanol, methylene chloride, n-hexane, naphthalene, polycyclic aromatic hydrocarbons, polycyclic organic matter, styrene, tetrachloroethane, toluene, and xylene. Metallic HAP from diesel fired stationary RICE that have been measured are: cadmium, chromium, lead, manganese, mercury, nickel, and selenium. Although numerous HAP may be emitted from RICE, only a few account for essentially all of the mass of HAP emissions from stationary RICE. These HAP are: formaldehyde, acrolein, methanol, and acetaldehyde. EPA is proposing to limit emissions of HAP through emissions standards for formaldehyde for non-emergency four stroke-cycle rich burn (4SRB) engines and through emission standards for carbon monoxide (CO) for all other engines.

The applicable emission standards (at 15% oxygen) or management practices for existing RICE located at area sources are provided in the table below.

In addition to emission standards and management practices, certain stationary CI RICE located at existing area sources are subject to fuel requirements. Stationary non-emergency diesel-fueled CI engines greater than 300 HP with a displacement of less than 30 liters per cylinder located at existing area sources must only use diesel fuel meeting the requirements of 40 CFR 80.510(b),

which requires that diesel fuel have a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

Subcategory	Emission standards at 15 percent O2, as applicable, or management practice	
	Except during periods of startup	**During periods of startup**
Non-Emergency 4SLB* >500HP	47 ppmvd CO or 93% CO reduction	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
Non-Emergency 4SLB ≤500HP	Change oil and filter every 1440 hours; inspect spark plugs every 1440 hours; and inspect all hoses and belts every 1440 hours and re-place as necessary.	Same as above
Non-Emergency 4SRB >500HP**	2.7 ppmvd formaldehyde or 76% formaldehyde reduction.	Same as above
Non-Emergency CI >500HP	23 ppmvd CO or 70% CO reduction	Same as above
Non-Emergency CI* 300-500HP**	49 ppmvd CO or 70% CO reduction	Same as above
Non-Emergency CI ≤300HP	Change oil and filter every 1000 hours; inspect air cleaner every 1000 hours; and inspect all hoses and belts every 500 hours and re-place as necessary.	Same as above

*4SLB - four stroke-cycle lean burn
**4SRB – four stroke-cycle rich burn
***CI – compression ignition

New York State

DEC

Appendix 18

Definition of Stationary Source or Facility for the Determination of Air Permit Requirements

Revised July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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Definition of Stationary Source or Facility
for the Determination of Air Permit Requirements

Summary

NYSDEC must determine the applicability of air permitting regulations and requirements to natural gas drilling activities in the Marcellus Shale formation. Specifically, NYSDEC must determine applicable regulations and permit requirements for:

• sources subject to stationary source permitting under 6 NYCRR Part 201.
major stationary source - one that emits or has the potential to emit any of the following:
100 tons per year (TPY) or more of any regulated air pollutant (NO_X, SO_2, CO,, PM2.5, PM_{10}); 50 TPY of VOC.
10 TPY or more of any individual Hazardous Air Pollutant (HAP); or
25 TPY or more of any combination of HAPs.

• sources subject to New Source Performance Standards (**NSPS**)

• sources subject to National Emission Standards for Hazardous Air Pollutants (**NESHAP**), and

• 6 NYCRR Part 231 for major new or major modifications to existing sources subject to preconstruction review requirements under Prevention of Significant Deterioration (**PSD**) and/or Non-Attainment New Source Review (**NSR**)

In addition to threshold criteria detailed in regulation and guidance, NYSDEC must evaluate a variety of technical and factual information to assess applicability of these rules to specific sources through the permit application process. These evaluations, as they pertain to natural gas drilling activities in the Marcellus Shale formation, are discussed herein, including 1) whether emissions from two or more pollutant-emitting activities should be aggregated into a single major stationary source for purposes of NSR and Title V programs; and 2) how to assess NESHAP applicability given the unique regulatory definition of "facility" for the oil and gas industry.

Major Stationary Source Determinations for Criteria Pollutants

PSD, NSR and Title V operating permit program (Title V) regulations apply to certain sources with the potential to emit pollutants in excess of the major source thresholds. To assess applicability, DEC must evaluate whether emissions from two or more pollutant-emitting activities should be aggregated into a single major stationary source. The evaluation begins with the federal definition of "stationary source" at 40 CFR 52.21(b)(5) and a similar definition for major source under 6 NYCRR 201-2.1(b)(21). The federal definition reads "any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant." "Building, structure, facility, or installation" is further defined in 40 CFR 52.21(b)(6):

> *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the *Standard Industrial Classification Manual, 1972*, as amended by the 1977 Supplement (U. S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

To identify pollutant-emitting activity that belongs to the same building, structure, facility, or installation, permitting authorities rely on the following three criteria: 1) whether the activities belong to the same industrial grouping; 2) whether the activities are located on one or more contiguous or adjacent properties; and 3) whether the activities are under the control of the same person (or person under common control).[1] These criteria are applied case-by-case to make the major stationary source determination.

Since the original SGEIS, DEC reviewed numerous source determinations from EPA permitting actions, guidance provided by EPA to inform permitting actions by other permitting authorities, and source determination protocol developed by other states. These documents have been informative. However, EPA has clearly stated that "no single determination can serve as an adequate justification for how to treat any other source determination for pollutant-emitting activities with different fact-specific circumstances." [2] "Therefore, while the prior agency statements and determinations related to oil and gas activities and other similar sources may be instructive, they are not determinative in resolving the source determination issue…, particularly where a state with independent permitting authority is making the determination and the prior agency statements had… substantially different fact-specific circumstances."[3]As such, DEC will formulate case-specific source determinations based on the foregoing, federal and state regulation, industry data and the specific facts of each air permit application. These determinations will be made during the review of permit applications for compressor stations which are associated with Marcellus Shale activities.

The three source determination criteria are discussed in more detail below.

1) **Do the pollutant-emitting activities belong to the same industrial grouping or "Major Group"?** In formulating the definition of "source," EPA uses a Standard Industrial Classification(SIC) code for distinguishing between sets of activities on the basis of their functional interrelationships.[4] Each source is to be classified according to its primary activity,

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[1] Memorandum from Gina McCarthy, EPA Assistant Administrator, to Regional Administrators, Sept. 22, 2009, available at http://www.epa.gov/region7/air/nsr/nsrmemos/oilgaswithdrawal.pdf
[2] Id.
[3] In The Matter Of Anadarko Petroleum Corporation, Frederick Compressor Station, Order Responding To Petitioners' Request That The Administrator Object To Issuance Of A State Operating Permit, February 2, 2011, Petition Number: VIII-2010-4.
[4] 45 FR 52695, at 31.

which is determined by its principal product or group of products produced or distributed, or services rendered.[5]

The Standard Industrial Classification Manual lists activities associated with oil and gas extraction in Major Group 13 and activities associated with natural gas transmission in Major Group 49. Establishments primarily engaged in operating oil and gas field properties, including wells, are grouped into Major Group 13. The Standard Industrial Classification Manual does not expressly list all equipment, such as midstream compressor stations, in Major Group 13, nor Major Group 49. Therefore, DEC may look to other information, such as federal and state regulations, industry data, and gas gathering agreements, to help make the source determination. For instance, under NESHAP, EPA regulates compressor stations that transport natural gas to a natural gas processing plant[6] in accordance with natural gas production facilities, Major Group 13.[7] In the absence of a natural gas processing plant, EPA regulates a compressor station in accordance with natural gas production facilities where the compressor station is prior to the point of custody transfer.[8] If the compressor station is after the point of custody transfer, EPA regulates the compressor station in accordance with natural gas transmission and storage facilities, Major Group 49. In relevant part, custody transfer means the transfer of natural gas to pipelines *after processing or treatment*.[9]

Where the pollutant-emitting activities do not belong to the same industrial grouping or "Major Group," DEC will ascertain whether one activity serves exclusively as a support facility for the other. In the Preamble to its 1980 PSD regulations, EPA "clarifies that "support facilities" that "convey, store, or otherwise assist in the production of the principal product*"* should be considered under one source classification, even when the support facility has a different two-digit SIC code.[10]

2**) Are the pollutant-emitting activities contiguous or adjacent?** EPA has routinely relied on the plain meaning of the word "contiguous," that is - being in actual contact; touching along a boundary or at a point. However, "the more difficult assessment is determining whether … a non-contiguous [pollutant-emitting activity] might be considered "adjacent."[11] First, EPA has not established a specific distance between activities in assessing whether such activities are adjacent.[12] Second, "the concept of "interdependency," which many individual EPA determinations consider, is not discussed in the 1980 Preamble or mentioned in the federal PSD or Title V regulations defining "source.*"*[13] "[I]nterdependency is a factor that has evolved over time in various case-by-case determinations. While interdependency is a consideration, it is not an express element of the actual three-part test set forth in regulation, and in the context of oil

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[5] 45 FR 52695, at 32.
[6] 40 CFR §63.761, *Natural gas processing plant.*
[7] 40 CFR §63.761, *Facility.*
[8] 40 CFR §63.760(a)(3)
[9] 40 CFR §63.761, *Custody transfer.*
[10] 45 Fed. Reg. 52676 (August 9, 1980)
[11] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 15, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf
[12] Id.
[13] Id. at 14

and gas infrastructure, it may have reduced relevance to an agency determination"[14] Nevertheless, to be thorough, DEC staff will evaluate the nature of the relationship between the facilities and the degree of interdependence between them to determine whether the non-contiguous emissions points should be aggregated.[15]

A "high level of connectedness and interdependence between two activities" is needed to deem them adjacent, and "interdependence requires that the two activities rely on each other – not just that one activity relies on the other activity.[16] Furthermore, "a determination of interdependence requires that the two activities rely upon each other *exclusively*; i.e., one activity cannot operate or occur without the other. The case-by-case determinations indicate that if activities operate independently and one activity does not act solely as a support operation for the other, the activities should not be deemed contiguous or adjacent."[17] In guidance provided by EPA to the Utah Division of Air Quality[18], EPA recommended using the following indicators as determinative of adjacency for two Utility Trailer Manufacturing Company facilities: 1) whether the location of the new facility was chosen because of its proximity to the existing facility; 2) whether materials would routinely be transferred back and forth between the two facilities; 3) whether managers and other workers would be shared between the two facilities; and 4) whether the production process itself would be split between the two facilities.[19] While DEC will use these and other questions to inform its source determination, some questions may have reduced relevance in the oil and gas industry. For instance, the location of oil and gas activity, proximate or otherwise, may "be controlled by land agreements, access issues, geologic formations, terrain, and, in other situations, by federal or state land management agencies, such as the Bureau of Land Management for oil and gas production on federal lands,"[20] and thus not necessarily indicative of a particular source category.

3) **Are the activities under common control?** To assess common control, EPA has historically relied on the Securities and Exchange Commission's definition of control as follows: The term control (including the terms controlling, controlled by and under common control with) means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person (or organization or association), whether through the ownership of voting shares, by contract or otherwise. The following questions have been used previously and in more recent actions by EPA to determine "common control" [21]: 1) Whether control has been

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[14] Id. at 36

[15] Letter from Cheryl Newton, U.S. EPA, to Scott Huber, Summit Petroleum Corporation, October 18, 2010, at 4, http://www.epa.gov/region07/air/title5/t5memos/singler5.pdf

[16] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 21, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

[17] Id. at 36 – 37.

[18] Letter from Richard Long of EPA Region VIII to Lynn Menlove of Utah Division of Air Quslity, dated May 21, 1998. http://www.epa.gov/region07/air/title5/t5memos/util-trl.pdf

[19] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 20, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

[20] Id. at 40

[21] Letter from Kathleen Henry of EPA Region III to John Slade of Pennsylvania DEP, dated 1/15/99. Also, Letter from Richard Long of EPA Region VIII to Margie Perkins, Air Pollution Control Division, Colorado Department of Public Health Environment, dated October 1, 1999, http://www.epa.gov/region07/air/nsr/nsrmemos/frontran.pdf

established through ownership of two entities by the same parent corporation or a subsidiary of the parent corporation; 2) Whether control has been established by a contractual arrangement giving one entity decision making authority over the operations of the second entity; 3) Whether there is a contract for service relationship between the two entities in which one sells all of its product to the other under a single purchase or contract; 4) Whether there is a support or dependency relationship between the two entities such that one would not exist "but for" the other?

Thus, DEC will use answers to the following questions to help guide the case-specific source determinations for natural gas drilling activities in the Marcellus Shale formation that may be subject to NSR and Title V for criteria pollutants.

1. Do the pollutant-emitting activities belong to the same industrial grouping or “Major Group” as described in the Standard Industrial Classification Manual?
    a. What is the primary activity engaged in by the facility?
    b. If the pollutant-emitting activities do not belong to the same industrial grouping or Major Group, does one activity serve exclusively as a support facility for the other?
2. Are the pollutant-emitting activities contiguous or adjacent?
    a. Are the pollutant-emitting activities contiguous? Do they share a boundary or touch each other physically?
    b. If the pollutant-emitting facilities are non-contiguous, are they proximate or interdependent?
    c. Was the location of the new facility chosen because of its proximity to the existing facility?
    d. Will materials routinely be transferred back and forth between the two facilities?
    e. Will managers and other workers be shared between the two facilities?
    f. Will the production process be split between the two facilities?
3. Are the activities under common control?
    a. Has control been established through ownership of two entities by the same parent corporation or a subsidiary of the parent corporation?
    b. Has control been established by a contractual arrangement giving one entity decision making authority over the operations of the second entity?
    c. Is there a contract for service relationship between the two entities in which one sells all of its product to the other under a single purchase or contract?
    d. Is there an exclusive support or dependency relationship between the two entities such that one would not exist "but for" the other?

NESHAPS Applicability for Hazardous Air Pollutants

"[I]n the hazardous air pollutant ("HAP") arena, EPA has expressly determined, consistent with Congress' statutory mandate in the [Clean Air Act] CAA, 42 U.S.C. § 7412(n)(4)(A), oil and gas production field facilities are typically not industrial facilities that should be aggregated."[22] The CAA, 42 U.S.C. § 7412, defines "major source" as any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants; and "area source" as any stationary source of hazardous air pollutants that is not a major source. Notwithstanding this definition, Section 7412(n)(4)(A) exempts oil and gas wells and pipeline facilities from the requirement to aggregate with contiguous sources under common control when deciding if the source is a major source for NESHAPS applicability.

In the context of hazardous air pollutants, EPA declared that "[s]uch facilities generally are not in close proximity to or co-located with one another (contiguous) and located within an area boundary, the entirety of which (other than roads, railroads, etc.), is under the physical control of the same owner."[23,24] In light of this, EPA developed a unique definition of facility for the oil and gas industry NESHAP regulations (40 CFR 63 Subparts HH and HHH). For HAP major source determinations, the EPA-promulgated definition of "facility" states that "pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts . . . or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility."[25,26] EPA defines a "surface site" at 40 CFR 63.761 of Subpart HH as " Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed".

Accordingly, to determine applicability of the NESHAPs rules governing Oil and Gas Production and Natural Gas Transmission industry sectors, the regulatory definition of facility authorized by CAA, 42 U.S.C. § 7412(n)(4)(A) and found at 40 CFR 63 Subparts HH and HHH, must be used. DEC will follow this definition in determining the regulatory applicability of NESHAPS requirements for HAPS. This opens up the possibility that a "facility" definition for a certain permit application may result in a determination of "major source" for purposes of NSR or Title V permitting, but which will consist of several area source surface sites for the purposes

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[22] Id. at 23
[23] 63 Fed. Reg. 6288, 6303 (Feb. 6, 1998)
[24] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 23, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf
[25] 64 Fed. Reg. 32610, 32630 (June 17, 1999)
[26] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 23, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

of NESHAP applicability. Guided by EPA's three source determination criteria and the underlying recommendation to use case specific facts, DEC will consider all pertinent information on a case-by-case basis in arriving at its conclusions during source permitting review.

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New York State

DEC

Appendix 18A

Evaluation of Particulate Matter and Nitrogen Oxides Emissions Factors and Potential Aftertreatment Controls for Nonroad Engines for Marcellus Shale Drilling and Hydraulic Fracturing

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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Evaluation of Particulate Matter and Nitrogen Oxides Emissions Factors and Potential Aftertreatment Controls for Nonroad Engines for Marcellus Shale Drilling and Hydraulic Fracturing Operations

Nonroad Emissions Standards

Tables 1 and 2 describe the EPA emissions standards for nonroad diesel engines relevant to natural gas well drilling and hydraulic fracturing. These standards are contained in 40 CFR Parts 89 and 1039. These standards may be considered worst case emission levels. Table 1 covers engines rated from 600-750 horsepower. Table 2 covers engines rated at more than 750 horsepower that are not installed in a generator set. Engines are held to these standards for a useful life of the lesser of 8000 hours or 10 years. Actual operating lifetimes are likely much longer.

Table 1 Nonroad Engine Standards for Engines Rated Between 600 and 750 Horsepower

Standard	Initial Year	PM (g/bhp*hr)	NOx (g/bhp/hr)	HC (g/bhp*hr)	Notes
Tier 1	1996	0.4	6.9	1.0	
Tier 2	2002	0.15	4.32	0.48	4.8 g/bhp*hr NOx + HC standard
Tier 3	2006	0.15	2.7	0.3	3.0 g/bhp*hr NOx + HC standard
Tier 4 interim	2011	0.01	1.35	0.14	NOx standard half-way between Tier 3 and Tier 4
Tier 4	2014	0.01	0.3	0.14	

Tier 2 and Tier 3 NO_x and hydrocarbon standards are an additive NO_x plus hydrocarbon (HC) standard. For Tier 2 the limit is 4.8 g/bhp*hr. For Tier 3 the limit is reduced to 3.0 g/bhp*hr. In order to use the standards as conservative emissions limits, it is necessary to apportion the emission limit between the two pollutants. The Tables apportions 90% of the emissions to NO_x and the remaining 10% to hydrocarbons. EPA and European Union (EU) emissions tiers that have separate NO_x and hydrocarbon standards, not requiring exhaust aftertreatment, generally have the NO_x standard equaling 86-88% of the sum of the two standards. It should be noted that data supplied on behalf of industry (1) assumed that 100% of these emissions are NO_x, which is deemed conservative.

There is no official "Tier 4 interim" standard for engines in the Table 1 horsepower class. Beginning in 2011, 50% of the engines in the class are supposed to meet the Tier 4 NO_x standards. This would increase to 100% in 2014. When faced with the exact same phase-in schedule from 2007-2010 for highway diesel engines, manufacturers universally chose to initially certify all engines to a Family Emissions Level half way between the old standard and the new standard, and postpone the NO_x aftertreatment requirements for three years. Thus, the NO_x emissions level of 1.35 g/bhp*hr in the Table is the average of the Tier 3 and Tier 4 standards.

Table 2 Nonroad Engine Standards for Engines Rated Above 750 Horsepower

Standard	Initial Year	PM (g/bhp*hr)	NOx (g/bhp/hr)	HC (g/bhp*hr)	Notes
Tier 1	2000	0.4	6.9	1.0	
Tier 2	2006	0.15	4.32	0.48	4.8 g/bhp*hr NOx + HC standard
Tier 4 interim	2011	0.075	2.6	0.3	
Tier 4 final	2015	0.03	2.6	0.14	

Tier 1 and Tier 2 standards for engines rated above 750 horsepower are the same as the corresponding standards for engines rated between 600 and 750 horsepower. Again, the Tier 2 NO_x plus hydrocarbon standard is apportioned 90% NO_x and 10% hydrocarbon. There are no Tier 3 standards for these engines. The Tier 4 interim standards are promulgated standards. Also, the Tier 4 standards for engines rated above 750 horsepower not installed in generator sets do not force the use of NO_x aftertreatment.

Retrofit of Exhaust Aftertreatment

Prior to Tier 4, none of the new engine standards were stringent enough to require exhaust aftertreatment. Current highway engine standards require aftertreatment to meet both the PM and NO_x standards. Furthermore, there is now substantial experience with retrofitting exhaust aftertreatment to highway engines and stationary engines. Technologies include: Diesel Oxidation Catalysts which oxidize hydrocarbons and carbon based particulate matter, Continuously Regenerating Diesel Particulate Filters or "Traps" (CRDPF) where particulate matter is collected and oxidized, and Selective Catalytic Reduction (SCR) which uses ammonia (usually supplied as urea) or "NO_x absorbers" to reduce NO_x emissions. Although in the past EPA had identified the NO_x absorbers as a promising technology, more recently it has not been proven to be so. Its use has been limited to certain light duty trucks and cars, but it has not been applied to the size class of the fracking engines. In addition, the "lean NO_x Catalyst" system noted by EPA to have a certain NO_x reduction would be insufficient to meet the ultimate engine standards. Thus, for NO_x control, the SCR system is recommended.

Table 3 lists the aftertreatment effectiveness claimed by one manufacturer, Johnson Matthey[1], as an example for retrofit installations on stationary engines (2).

[1] Listing of this manufacturer does not imply any form of endorsement. Other manufacturers could provide similar aftertreatment information.

Table 3 Exhaust Aftertreatment Retrofit Effectiveness

Technology	Abbreviation	PM Emissions Reduction (%)	NOx Emissions Reduction (%)	HC Emissions Reduction (%)
Diesel Oxidation Catalyst	DOC	30%	0	90%
Particulate Trap	CRDPF	85%	0	90%
Particulate Trap and SCR	SCR-DPF (SCRT)	85%	90%	90%

Johnson Matthey has EPA certification of its SCR-DPF system (referred to as SCRT) as a verified retrofit for some classes of highway diesel engines. That verification is for a 70% NO_x emissions reduction (3). The development of Johnson Matthey's retrofit system is described by Conway and coworkers (4). This certification does not negate the 90% reduction expected for these nonroad engines due to factors discussed below.

The SCR and CRDPF technologies are the dominant technologies used to meet the current highway emissions standards, and are expected to dominate the market for large nonroad diesel engine exhaust aftertreatment. There are other NO_x control technologies; however their applicability appears to be limited to smaller engines, such as those in light duty vehicles. Although the engines used in drilling and hydraulic fracturing are defined in regulation as nonroad mobile engines, they are physically static during drilling or hydraulic fracturing. They also have a relatively steady duty cycle, without the frequent transient operation seen in motor vehicles. Thus, the engineering and operational challenges associated with exhaust aftertreatment retrofits should be reduced in comparison to highway vehicles. It should also be easier to achieve higher NO_x reduction levels with SCR.

The exhaust temperatures reported on behalf of industry (800-900 °F) (1) are high enough to support aftertreatment retrofits which require minimum temperatures of roughly 250 °C (<500 °F) (3) (4).

Emissions of Nitrogen Dioxide

Nitrogen Dioxide (NO_2) is not explicitly regulated via EPA engine emissions standards. It is a component of the regulated pollutant NO_x. However, primary NO_2 emissions are a concern in our Marcellus Shale evaluation due to the new 1 hour NO_2 standard and specific emission factor estimates are necessary to assure that modeling results account for the NO_2 portion of the emissions.

Conventional information has been that roughly 5% of NO_x emissions from internal combustion engines are NO_2; the balance are NO. However, European researchers have noted that ambient NO_2 concentrations have not been declining despite declining NO_x emissions from engines and vehicles. This has led to some investigation of the NO_2 fraction of primary NOx emissions from highway vehicles. The most comprehensive summary is by Grice, et al (5), who needed the data

for model inputs. These researchers found that the conventional use of 5% NO_2 holds for gasoline engines. The NO_2 fraction for diesel engines varies for different emissions control technologies, but is always greater than 5%. The data are summarized based on European emissions standards which must be translated into aftertreatment technology level.

NO_2 fractions for diesels range between 10% and 55% (5). EURO II engines, which have no exhaust aftertreatment, have a NO_2 fraction of 11%. This NO_2 fraction is used for Tier 1, Tier 2, and Tier3 engines with no retrofitted aftertreatment. For particulate trap equipped EURO III engines the NO_2 fraction is 35%. This NO_2 fraction is used for cases with either a DOC or a CRDPF either standard or retrofitted. The oxidation reactions in DOCs oxidize some NO to NO_2 along with the desired oxidation of hydrocarbons and particulate carbon. Indeed, oxidation catalysts are placed ahead of CRDPFs to produce NO_2 for use in oxidizing particulate matter to regenerate the PM trap. NO_2 oxidizes carbon at a lower temperature than O_2.

Finally, Grice and coworkers chose to use a NO_2 fraction of 10% for engines equipped with SCR (EURO IV and later). However, the data for the SCR equipped engines was particularly sparse. This uncertainty is discussed further below.

For light duty vehicles equipped with NO_x aftertreatment a NO_2 fraction of 55% was reported. Light duty vehicle NO_x control generally avoids SCR, with its requirement that the operator maintain the urea supply. These alternative NO_x aftertreatment technologies have not proven viable for heavy duty truck engines, never mind the even larger engines to be used in Marcellus Shale drilling and hydraulic fracturing. Thus the 55% NO_2 fraction does not have any applicability here.

Table 4 below summarizes the recommended NO_2 fractions.

Table 4 NO_2 Emissions as Fraction of NO_x Emissions

Technology	Fraction NO_2 (in %)
No Exhaust Aftertreatment	11
Diesel Oxidation Catalyst or Particulate Trap	35
SCR (with or without DOC or CRDPF)	10 (see text)

Specifying a single NO_2 fraction for an engine technology is clearly a simplification. Researchers have documented variation in the NO_2 fraction depending on engine load (6) and exhaust temperature (7). The NO_2 fractions in Table 4 for engines without SCR could be low for engines operated at low loads and low exhaust temperatures. They appear to better reflect the emissions at higher loads more in line with the operations expected during drilling and hydraulic fracturing.

Given the particularly high level of uncertainty regarding the NO_2 fraction when SCR is used, a review of the chemistry involved might help. SCR generally converts NO_x to N_2. There are several different reactions involved (8), (9), (10). One of these reactions, the “fast” SCR reaction is much faster (and has lower minimum temperature requirements) than the others.

$$2NH_3 + NO + NO_2 \rightarrow 2N_2 + 3H_2O$$

The fast SCR reaction generally goes to completion before any of the other reactions become significant. This leads to a desire to have a NO_2 fraction near 50% at the SCR reactor inlet. However, given variations on the NO_2 consumption by a CRT and variations in engine load and engine out exhaust gas composition, consistently providing the SCR reactor with a 50:50 NO_2 to NO ratio would be quite difficult.

As long as the exhaust gases remain in the SCR reactor after the fast SCR reaction has exhausted one of the NO_x species, other chemical reactions will continue to reduce NO_x. The reaction for NO produces nitrogen and water. Several competing reactions are possible for NO_2. Some of these produce ammonium nitrate or nitrous oxide in addition to nitrogen.

Another concern with SCR is "ammonia slip," the emission of ammonia injected into the exhaust stream but not consumed. Oxidation catalysts are employed after SCR reactors to oxidize ammonia to nitrogen. This catalyst could also oxidize NO to NO_2. Thus, it cannot be completely ruled out that NO_x emissions from SCR equipped engines may consist of more than 10% NO_2 , possibly with an upper bound of 0.35%. However, further review of the literature regarding the chemistry of ammonia slip catalysts leads to the conclusion that oxidation of NO to NO_2 is not a major concern. The desired reaction in the ammonia slip catalyst is the oxidation of ammonia to nitrogen and water. Competing reactions form NO and N_2O, but not NO_2 (2). The fate of NO in an ammonia slip catalyst is to react with ammonia and form N_2O. NO_2 production would likely only begin if the ammonia was exhausted. The chemical reaction mechanism of ammonia oxidation is well known, it is an intermediate step in the industrial production of nitric acid (3). Given that there is no apparent path to NO_2 formation as long as NH_3 is present, greater confidence can be placed in a NO_2 emission estimate of 10% of NO_x for SCR equipped engines.

Thus, actual data summarized by Grice and coworkers, although sparse, currently suggests that we consider the DOC/CRDPF NO_2 fraction of 10% as the appropriate factor. Regardless of the actual NO_2 fraction of the NOx emissions from a SCR equipped engine (retrofitted or standard), SCR will provide the lowest NO_2 and NO_x emissions achievable with diesel engines.

Emission Rates for Various Emissions Standards Tiers & Exhaust Aftertreatment Retrofit Options

Considering the different Tiers of engine standards, the variety of possible exhaust aftertreatment retrofits, and the uncertainty in the NO_2 fraction of NO_x emissions from SCR equipped engines, there are in excess of 20 different emissions cases possible. Calculations were performed by Barnes, (11) (12), but only the pertinent part of these results are presented in Tables 5 and 6.

These emissions rates are estimated from the relevant U.S. EPA standards presented in Tables One and Two. In cases where a NOx + HC standard was promulgated, the standard is apportioned 90% NO_x, 10% HC. Effectiveness of exhaust aftertreatment retrofits are based on Table Three. Where the claimed retrofit effectiveness reduces an emission rate below a subsequent standard expected to require the same exhaust aftertreatment technology the subsequent standard (the higher number) is used as the emissions rate. NO_2 emission rates are

calculated from NO_x emission rates using factors presented in Table Four. For SCR equipped engines the NO_2 fraction of 10 of the NOx emissions is presented.

Table 5 Emissions Factors for Engines between 600 and 750 Horsepower

Air Drilling Engines

Standard	Effective Year	Retrofit	PM (g/bhp*hr)	NOx (g/bhp*hr)	HC (g/bhp*hr)	NO_2 (g/bhp*hr)
Tier 1	1996	None	0.4	6.9	1.0	0.759
		DOC	0.28	6.9	0.14	2.415
		CRDPF	0.06	6.9	0.14	2.415
		SCR-DPF	0.06	0.69	0.14	0.069
Tier 2	2002	None	0.15	4.32	0.48	0.475
		DOC	0.105	4.32	0.14	1.512
		CRDPF	0.03	4.32	0.14	1.512
		SCR-DPF	0.03	0.432	0.14	0.043
Tier 3	2006	None	0.15	2.7	0.3	0.297
		DOC	0.105	2.7	0.14	0.945
		CRDPF	0.03	2.7	0.14	0.945
		SCR-DPF	0.03	0.3	0.14	0.03
Tier 4	2011	None	0.01	1.35	0.14	0.473
		SCR	0.01	0.3	0.14	0.03
Tier 4	2014	None	0.01	0.3	0.14	0.03

Table 6 Emissions Factors for Engines Greater than 750 Horsepower

Drilling Rig and Hydraulic Fracturing Engines

Standard	Effective Year	Retrofit	PM (g/bhp*hr)	NOx (g/bhp*hr)	HC (g/bhp*hr)	NO_2 (g/bhp*hr)
Tier 1	2000	None	0.4	6.9	1.0	0.759
		DOC	0.28	6.9	0.14	2.415
		CRDPF	0.06	6.9	0.14	2.415
		SCR-DPF	0.06	0.69	0.14	0.069
Tier 2	2006	None	0.15	4.32	0.48	0.475
		DOC	0.105	4.32	0.14	1.512
		CRDPF	0.03	4.32	0.14	1.512
		SCR-DPF	0.03	0.432	0.14	0.043
Tier 4 interim	2011	None	0.075	2.6	0.3	0.91
		CRDPF	0.03	2.6	0.14	0.91
		SCR-DPF	0.03	0.3	0.14	0.03
Tier 4	2015	None	0.03	2.6	0.14	0.91
		SCR-DPF	0.03	0.3	0.14	0.03

Summary

Between 2000 and 2015 nonroad engines will have gone through four or five (depending on engine power) different sets of emissions standards. PM mass reduction over this timeframe will be 93% for the largest engines and 98% for engines rated between 600 and 750 horsepower. NOx emissions will be reduced 96% for the 600 to 750 horsepower engines, but only 62% for the larger engines. Much of these emissions reductions can be achieved without premature replacement of older engines by retrofitting exhaust aftertreatment to these engines. A key consideration with these retrofits is that PM aftertreatment in the absence of SCR will increase NO_2 emissions. This concern also applies to current and future Tier 4 engines which may have PM aftertreatment but not NOx aftertreatment.

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Appendix 18B

Cost Analysis of Mitigation of NO_2 Emissions and Air Impacts by Selected Catalytic Reduction (SRC) Treatment

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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Cost Analysis of Mitigation of NO_2 Emissions and Air Impacts by Selected Catalytic Reduction (SRC) Treatment

1. Introduction

In order to mitigate modeled exceedences of the National Ambient Air Quality Standards (NAAQS) for nitrogen dioxide (NO_2) the SGEIS has recommended that the hydraulic fracturing engines (and tier 1 drilling engines) used in the development of gas production wells in the Marcellus formation in New York State must be equipped with post-combustion controls. Selective catalytic reduction (SCR) is the recommended technology for addressing NO_2 concerns (see Appendix 18A). SCR is a proven technology for reducing oxides of nitrogen (NO_x) emissions from combustion sources. This technology involves the use of a urea solution (32.5 percent urea) which converts NO_x to nitrogen gas on a catalyst.

To determine the viability of the SCR control use for the hydraulic fracturing engines in terms of the associated costs, an approximate estimate of mitigation cost is presented in this appendix. It should be noted that these estimates are not necessarily representative of the actual costs which industry will experience. The purpose of these estimates is to determine the cost per ton of NOx removal for a relative comparison to cost thresholds used by the Department for NOx RACT purposes at stationary sources.[1] In addition, it should be noted that any reference to specific manufacturers (in footnotes) does not constitute an endorsement, but merely presents the specific information source.

First, an estimate is developed regarding how many jobs and how many hours a hydraulic fracturing engine could be used each year. In the third section, the costs of installing and operating an SCR system on a typical 2250 hp hydraulic fracturing engine are presented. In the fourth section the cost per ton of NO_x removed from the exhaust stream is compared with the NO_x RACT cost threshold used for stationary sources. A summary of the findings of this investigation are presented in the final section.

2. Operation of Hydraulic Fracturing Engines

According to ALL Consulting, hydraulic fracturing engines will be used at any given well pad for no more than 14 days. Mobilization and de-mobilization activities are expected to take a total of four days. Hydraulic fracturing activities are expected to take ten days per well pad (five days per well).[2] At most, a hydraulic fracturing engine could be used for 26 jobs per year. Allowing for additional travel time, maintenance and vacations, the Department is assuming an engine will be used for approximately 20 jobs per year in the Marcellus play. Further, it was assumed that these engines will be used for a maximum of five hydraulic fracturing events per day and will operate two hours per event at their maximum loading and emissions.[3] Therefore, a hydraulic fracturing engine could be used up to 2,000 hours per year at their maximum load:

$$(20\ \text{jobs/year})(10\ \text{days/job})(5\ \text{fracs/day})(2\ \text{hours/frac}) = 2{,}000\ \text{hours/year}$$

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[1] Hydraulic fracturing engines are considered nonroad sources.
[2] "NY DEC SGEIS Information Requests", ALL Consulting, September 16, 2010, page 39.
[3] "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, page 9.

3. Reduction of Oxides of Nitrogen and Costs

Selective catalytic reduction (SCR) is a proven technology for reducing NO_x emissions and the Department is assuming that this technology will be preferentially used to reduce NO_x emissions from hydraulic fracturing engines. The Department considered capital, periodic and annual costs in the cost estimates discussed in this section.

Capital Costs

The capital cost for a SCR system was assumed to be $16 per hp.[4] It was assumed that the scale-up factor was one. Installation costs were assumed to be 60 percent of the system cost.[5] Taxes were assumed to be eight (8) percent of the system cost. The estimated capital cost for a typical 2250 hp hydraulic fracturing engine is $60,480 as detailed below:

System Cost:	$36,000
Installation:	$21,600
Taxes:	$ 2,880
Total:	$60,480

As noted previously, these costs are used in order to estimate the "cost effectiveness" value for the purpose of comparisons to "thresholds" used by the Department.

Periodic Costs

The periodic costs considered by the Department were for replacing SCR catalysts every five years.[6] It was assumed that the replacement costs were seven (7) percent of the system costs[7] and installation 60 percent of the replacement cost. The periodic costs (at year 5) were estimated to be $4,032 as detailed below:

Catalyst Replacement:	$2,520
Installation:	$1,512
Total:	$4,032

Annual Costs

Reagent (urea) costs are the primary costs in this category. The quantity of reagent used depends upon the amount of NO_x coming from the engine. The control efficiency for SCRs was assumed

[4] The cost for a Volvo SCR is reported to be $9600 ("2010-Compliant Diesel Truck Price Increases Out – The Changing Paradigm", Jay Thompson, www.glgroup.com/NewsWatchPrefs/Print.aspx?pid=42461, August 14, 2009). Further, it was assumed the power rating for a typical truck is 600 hp.

[5] Plant Design and Economics for Chemical Engineers, Third Edition, M.S. Peters and K. D. Timmerhaus, 1980, pages 168-169.

[6] E-mail from Wilson Chu (Johnson Matthey) to John Barnes (NYSDEC) dated January 24, 2008.

[7] E-mail from Chad Whiteman (Institute of Clean Air Companies) to John Barnes dated November 27, 2007 and e-mail from Wilson Chu (Johnson-Matthey) to John Barnes dated January 24, 2008..

to be 90 percent for engines. The emission rates factored into this analysis are presented in Table 1 (see Appendix 18B). Further, it was assumed that hydraulic fracturing engines will be operated at 50 percent of capacity.[8] The urea requirement for each pound of NO_x treated in an SCR is 0.2088 gallons.[9]

Table 1: NO_x Emission Rates for Tier 2, Interim 4 (I4) and 4 Hydraulic Fracturing Engines

Tier #	NO_x (without control)[10] (g/bhp-h)	NO_x (with control) g/bhp-h
2	4.32	0.43
Interim 4 (I4)	2.60	0.26
4	2.60	0.26

The urea requirements range from 1.21 gallons per hour (gal/h) for a Tier 4 engine to 2.01 gal/h for a Tier 2 engine. The estimated cost of urea is $3.67 per gallon.[11]

In addition to the reagent requirements, annual insurance costs were estimated to be one (1) percent of the system cost[12] and maintenance costs were assumed to be six (6) percent of the system cost.[13] A summary of the annual costs is presented below:

	Tier 2	Tier I4	Tier 4
Reagent:	$14,800	$9,200	$8,900
Insurance:	$ 600	$ 600	$ 600
Maintenance:	$ 3,600	$3,600	$3,600
Total:	$19,000	$13,400	$13,100

Annualized Cost

A discount rate of seven (7) percent was used to convert the above costs into an equivalent annual cost for a 10-year horizon. The estimated annualized costs are presented in the next section.

4. Cost Effectiveness Analysis

The cost effectiveness of applying SCR controls on Tier 2, I4 and 4 hydraulic fracturing engines is presented in Table 2. By comparison, the current cost threshold for the NO_x standards used by the Department to judge the cost effectiveness of control limits as set forth in Subpart 227-2 Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x) is $5,500 per

[8] "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, p. 10.
[9] E-mail from Michael Baran (Johnson Matthey) to John Barnes, April 17, 2008.
[10] See Appendix 18A
[11] E-mail from Wilson Chu (Johnson Matthey) to John Barnes (NYSDEC) dated January 24, 2008. Also factored was Consumer Price Index data: www.bls.gov/cpi/cpid0801.pdf and www.bls.gov/cpi/cpid0211.pdf.
[12] Plant Design and Economics for Chemical Engineers, Third Edition, M.S. Peters and K. D. Timmerhaus, 1980, page 202.
[13] IBID, page 200.

ton of NO_x removed from the exhaust gas. This value is used in determining whether a "waiver" should be granted to a major stationary source which demonstrates that the cost of such controls is unreasonable. As an analogy, the Subpart 227-2 NO_x standard that would apply to hydraulic fracturing engines if they were considered stationary sources is 2.3 g/bhp-h. Hydraulic fracturing engines equipped with SCRs will have emission rates ranging from 0.26 g/bhp-h (Tier I4) to 0.43 g/bhp-h (Tier 2).

Table 2: Cost Effectiveness of SCR Control on Hydraulic Fracturing Engines

Engine Tier	Annualized Cost	NO_x Removed (tons)	Cost Effectiveness (ton^{-1})
2	$28,000	9.64	$2,907
I4	$22,500	6.03	$3,732
4	$22,000	5.80	$3,816

Summary and Recommendations

The costs for mitigating the modeled NO_2 NAAQS exceedences are considered reasonable. The costs of control presented in Table 2 are less than the cost threshold for the Department's Reasonably Available Control Technology (RACT) for NO_x which is $5,500 per ton. The NO_x emission limits for these engines will range from 0.26 g/bhp-h (Tier 4) to 0.43 g/bhp-h (Tier 2). Therefore, it is concluded that the large (2250 hp) hydraulic fracturing engines can be, cost-effectively, equipped with SCR control systems as recommended in the SGEIS.

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Appendix 18C

Regional On-Road Mobile Source Emission Estimates from EPA's MOVES Model and Single Pad PM2.5 Estimates from MOBILE 6 Model

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2007 Annual Mobile Source Emissions

MOVES 2010a Based Inventory Runs

Includes all MOVES Emission Processes Except Evap. Permeation, Evap. Vapor Venting & Evap. Fuel Leaks

		Base Emissions						Emissions resulting from additonal VMT from proposed drilling activity					
FIPS	County	NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO	NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
		(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)
36001	ALBANY	8423.0	3323.7	64.2	356.3	339.0	51044.0	8447.2	3326.2	64.3	357.6	340.2	51067.1
36003	ALLEGANY	1436.5	495.0	8.5	63.8	60.9	7205.9	1458.5	497.1	8.6	64.8	61.9	7227.5
36007	BROOME	4807.1	1998.9	36.2	209.0	198.5	30424.5	4830.2	2001.2	36.3	210.2	199.6	30447.8
36009	CATTARUAGUS	2446.6	839.0	15.0	107.9	103.0	12115.4	2468.7	841.2	15.0	108.9	104.0	12137.9
36011	CAYUGA	2020.5	774.2	13.6	84.0	80.2	11210.1	2043.2	776.5	13.7	85.2	81.3	11231.9
36013	CHAUTAQUA	4178.1	1410.3	26.5	184.6	176.3	20379.8	4200.5	1412.5	26.6	185.7	177.3	20402.2
36015	CHEMING	2113.2	861.3	15.1	89.3	85.2	12366.7	2137.1	863.8	15.1	90.5	86.4	12390.9
36017	CHENANGO	1066.9	510.5	7.9	43.8	41.5	7513.7	1089.4	512.8	7.9	44.9	42.6	7535.9
36023	CORTLAND	1653.3	543.1	11.1	71.8	68.5	8158.8	1675.5	545.3	11.1	72.9	69.6	8180.9
36025	DELAWARE	1224.2	539.2	9.0	50.1	47.5	8013.5	1246.3	541.3	9.1	51.1	48.6	8034.7
36029	ERIE	19260.0	7997.4	138.2	798.8	760.4	117094.0	19282.6	7999.7	138.3	799.9	761.5	117116.0
36037	GENESEE	3035.1	855.2	20.5	127.1	121.5	13116.7	3057.1	857.4	20.6	128.2	122.6	13138.1
36039	GREENE	1997.6	672.1	14.1	83.1	79.3	10151.8	2020.1	674.4	14.2	84.2	80.4	10174.1
36051	LIVINGSTON	1911.9	683.9	12.3	83.5	79.6	10006.3	1934.2	686.1	12.4	84.6	80.7	10028.8
36053	MADISON	1797.8	729.6	13.1	73.4	69.9	10881.9	1820.3	731.8	13.2	74.6	71.0	10903.7
36065	ONEIDA	4997.0	2222.6	38.1	211.2	200.7	32376.2	5020.6	2225.1	38.1	212.4	201.8	32399.3
36067	ONONDAGA	11468.5	4535.9	82.3	501.2	477.7	66575.9	11492.9	4538.4	82.4	502.4	479.0	66600.0
36069	ONTARIO	3628.0	1241.3	25.5	150.8	144.0	18507.6	3650.8	1243.7	25.6	152.0	145.1	18529.9
36071	ORANGE	7527.5	3123.6	49.7	302.3	286.3	53982.4	7551.6	3126.0	49.8	303.6	287.5	54005.2
36077	OTSEGO	1620.0	640.5	11.4	70.1	66.6	9659.1	1641.8	642.6	11.5	71.1	67.6	9681.4
36095	SCHOHARIE	1505.6	496.2	11.6	62.0	59.0	7964.9	1527.7	498.4	11.7	63.1	60.1	7987.0
36097	SCHUYLER	558.3	215.0	3.8	22.8	21.7	3102.1	580.9	217.4	3.9	23.9	22.9	3122.9
36099	SENECA	1234.1	401.9	8.3	52.1	49.8	5979.4	1256.6	404.2	8.4	53.2	50.8	6002.1
36101	STEUBEN	3969.5	1197.4	24.2	173.8	166.3	17845.0	3991.3	1199.5	24.3	174.9	167.3	17867.0
36105	SULLIVAN	1481.6	752.4	11.8	58.4	55.3	11050.7	1504.9	754.7	11.9	59.6	56.5	11070.8
36107	TIOGA	1398.8	599.9	10.5	57.6	54.9	8538.5	1423.3	602.6	10.6	58.9	56.2	8561.8
36109	TOMPKINS	1727.3	790.5	12.8	72.3	68.8	11227.7	1751.6	793.1	12.9	73.5	70.1	11250.9
36111	ULSTER	4114.3	1895.8	36.0	156.2	148.2	29231.2	4138.3	1898.4	36.1	157.5	149.4	29254.8
36121	WYOMING	999.9	414.6	6.5	42.3	40.4	5827.2	1022.8	416.9	6.6	43.5	41.5	5847.9
36123	YATES	477.8	222.1	3.2	19.3	18.4	3152.6	500.8	224.5	3.3	20.5	19.6	3173.5

	Total For Counties in Marcellus Shale Area		104,080	40,983	741	4,379	4,170	614,703		104,767	41,053	743	4,413	4,203	615,372
		Estimated additional mobile source emissions resulting from additional VMT associated with proposed gas drilling *								Percentage increase in emissions assuming all wells operating					
										NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
		NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO			0.66%	0.17%	0.33%	0.79%	0.80%	0.11%
		(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)								
		686.7	70.0	2.5	34.4	33.3	668.6								
		Well pad emissions assuming total emissions split equally across all													
		0.28	0.03	0.00	0.01	0.01	0.27								

* Does NOT include Evaporative emissions processes

Marcellus Single Pad MOBILE Model Emissions of PM2.5 for CP-33 Comparison

Vehicle Trip Emissions

Vehicle Type	Range of Trucks	Max Number of Trucks	Feet travelled per site*	Distance travelled per truck (miles)	PM 2.5 EF (lbs/mile)	Emissions (tons)
Drill Pad and Road Construction Equipment	10-45	45	1700	14.49	0.0003	2.18799E-06
Drilling Rig	30	30	1700	9.66	0.0003	1.45866E-06
Drilling Fluid and Materials	25-50	50	1700	16.10	0.0003	2.4311E-06
Drilling Equipment (casing, drill pipe, etc.)	25-50	50	1700	16.10	0.0003	2.4311E-06
Completion Rig	15	15	1700	4.83	0.0003	7.2933E-07
Completion Fluid and Materials	10-20	20	1700	6.44	0.0003	9.72439E-07
Completion Equipment – (pipe, wellhead)	5	5	1700	1.61	0.0003	2.4311E-07
Hydraulic Fracture Equipment (pump trucks, tanks)	150-200	200	1700	64.39	0.0003	9.72439E-06
Hydraulic Fracture Water	400-600	600	1700	193.18	0.0003	2.91732E-05
Hydraulic Fracture Sand	20-25	25	1700	8.05	0.0003	1.21555E-06
Flow Back Water Removal	200-300	300	1700	96.59	0.0003	1.45866E-05
Total		**1340**		**431.44**		**6.51534E-05**

*(1 - 750 foot trip onto site, 1 - 100 foot trip to station, 1- 100 foot trip back from the station and 1-750 foot trip off the site)

Vehicle Idle Emissions

Vehicle Type	Range of Trucks	Max Number of Trucks	Idle Time per truck (hrs)**	Hours idling per truck type (hrs)	PM 2.5 EF (lbs/hr)	Emissions (tons)
Drill Pad and Road Construction Equipment	10-45	45	2	90.00	0.0013	5.74901E-05
Drilling Rig	30	30	2	60.00	0.0013	3.83267E-05
Drilling Fluid and Materials	25-50	50	2	100.00	0.0013	6.38779E-05
Drilling Equipment (casing, drill pipe, etc.)	25-50	50	2	100.00	0.0013	6.38779E-05
Completion Rig	15	15	2	30.00	0.0013	1.91634E-05
Completion Fluid and Materials	10-20	20	2	40.00	0.0013	2.55511E-05
Completion Equipment – (pipe, wellhead)	5	5	2	10.00	0.0013	6.38779E-06
Hydraulic Fracture Equipment (pump trucks, tanks)	150-200	200	2	400.00	0.0013	0.000255511
Hydraulic Fracture Water	400-600	600	2	1200.00	0.0013	0.000766534
Hydraulic Fracture Sand	20-25	25	2	50.00	0.0013	3.19389E-05
Flow Back Water Removal	200-300	300	2	600.00	0.0013	0.000383267
Total		**1340**		**2680.00**		**0.001711927**

** Assume each truck idles at least 2 hours over the duration of the project

Road Dust Emissions

Vehicle Type	Range of Trucks	Max Number of Trucks	Feet travelled per site*	Distance travelled per truck (miles)	PM 2.5 EF (lbs/mile)	Emissions (tons)
Drill Pad and Road Construction Equipment	10-45	45	1700	14.49	0.0863	0.000625511
Drilling Rig	30	30	1700	9.66	0.0863	0.000417007
Drilling Fluid and Materials	25-50	50	1700	16.10	0.0863	0.000695012
Drilling Equipment (casing, drill pipe, etc.)	25-50	50	1700	16.10	0.0863	0.000695012
Completion Rig	15	15	1700	4.83	0.0863	0.000208504
Completion Fluid and Materials	10-20	20	1700	6.44	0.0863	0.000278005
Completion Equipment – (pipe, wellhead)	5	5	1700	1.61	0.0863	6.95012E-05
Hydraulic Fracture Equipment (pump trucks, tanks)	150-200	200	1700	64.39	0.0863	0.002780047
Hydraulic Fracture Water	400-600	600	1700	193.18	0.0863	0.008340142
Hydraulic Fracture Sand	20-25	25	1700	8.05	0.0863	0.000347506
Flow Back Water Removal	200-300	300	1700	96.59	0.0863	0.004170071
Total		**1340**		**431.44**		**0.018626317**

Total PM 2.5 Emissions	Emissions (tons)	Emissions (lbs)
Vehicle Trip Emissions	6.51534E-05	0.13
Vehicle Idle Emissions	0.001711927	3.42
Road Dust Emissions	1.86E-02	37.25
Total	**0.02**	**40.81**

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Appendix 19

Greenhouse Gas (GHG) Emissions

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Part A

GHG Tables

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GHG Tables (Revised July 2011, following replaces tables released in September 2009)

Table GHG-1 – Emission Rates for Well Pad[1]

Emission Source/ Equipment Type	CH_4 EF	CO_2 EF	Units	EF Reference[2]
Fugitive Emissions				
Gas Wells				
Gas Wells	0.014	0.00015	lbs/hr per well	Vol 8, page no. 34, table 4-5
Field Separation Equipment				
Heaters	0.027	0.001	lbs/hr per heater	Vol 8, page no. 34, table 4-5
Separators	0.002	0.00006	lbs/hr per separator	Vol 8, page no. 34, table 4-5
Dehydrators	0.042	0.001	lbs/hr per dehydrator	Vol 8, page no. 34, table 4-5
Meters/Piping	0.017	0.001	lbs/hr per meter	Vol 8, page no. 34, table 4-5
Gathering Compressors				
Large Reciprocating Compressor	29.252	1.037	lbs/hr per compressor	GRI - 96 - Methane Emissions from the Natural Gas Industry, Final Report
Vented and Combusted Emissions				
Normal Operations				
1,775 hp Reciprocating Compressor	not determined	1,404.716	lbs/hr per compressor	6,760 Btu/hp-hr, 2004 API, page no. 4-8
Pneumatic Device Vents	0.664	0.024	lbs/hr per device	Vol 12, page no. 48, table 4-6
Dehydrator Vents	12.725	0.451	lbs/MMscf throughput	Vol 14, page no. 27
Dehydrator Pumps	45.804	1.623	lbs/MMscf throughput	GRI June Final Report
Blowdowns				
Vessel BD	0.00041	0.00001	lbs/hr per vessel	Vol 6, page no. 18, table 4-2
Compressor BD	0.020	0.00071	lbs/hr per compressor	Vol 6, page no. 18, table 4-2
Compressor Starts	0.045	0.00158	lbs/hr per compressor	Vol 6, page no. 18, table 4-2
Upsets				
Pressure Relief Valves	0.00018	0.00001	lbs/hr per valve	Vol 6, page no. 18, table 4-2

[1] Adapted from Exhibit 2.6.1, ICF Incorporated, LLC. *Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs*, Agreement No. 9679, August 2009., pp 34-35.

[2] Unless otherwise noted, all emission factors are from the Gas Research Institute, *Methane Emissions from the Natural Gas Industry*, 1996. Available at: epa.gov/gasstar/tools/related.html.

Table GHG-2 – Drilling Rig Mobilization, Site Preparation and Demobilization – GHG Emissions

	Single Vertical, Single Horizontal or Four-Well Pad[3]				
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Vented Emissions (tons CH_4)**	**Combustion Emissions Light Truck & Heavy Truck Combined Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation [4]	432	NA	NA	4	NA
Drill Pad and Road Construction [5]	NA	48 hours	NA	11	NA
Total Emissions	432	NA	NA	15	NA

Table GHG-3 – Completion Rig Mobilization and Demobilization – GHG Emissions

	Single Vertical, Single Horizontal or Four-Well Pad				
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Vented Emissions (tons CH_4)**	**Combustion Emissions Light Truck & Heavy Truck Combined Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Completion Rig[6]	432	NA	NA	4	NA
Total Emissions	432	NA	NA	4	NA

[3] Site preparation for a single vertical well would be less due to a smaller pad size but for simplification site preparation is assumed the same for all well scenarios considered.
[4] ALL Consulting, 2011, Exhibit19B.
[5] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[6] ALL Consulting, 2011, Exhibit19B. Completion rig mobilization likely less than that for drilling rig but for simplification assumed the same.

Table GHG-4 – Well Drilling – Single Vertical Well GHG Emissions

	Single Vertical Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[7]	788	NA	NA	NA	9	NA
Power Engines[8]	NA	132 hours	1	NA	74	NA
Circulating System[9]	NA	132 hours	1	negligible	NA	negligible
Well Control System[10]	NA	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	NA	negligible	83	negligible

[7] ALL Consulting, 2011, Exhibit 20B.
[8] Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[9] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[10] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-5 – Well Drilling – Single Horizontal Well GHG Emissions

	Single Horizontal Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[11]	2,298	NA	NA	NA	26	NA
Power Engines[12]	NA	300 hours	1	NA	168	NA
Circulating System[13]	NA	300 hours	1	negligible	NA	negligible
Well Control System[14]	NA	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	NA	negligible	194	negligible

[11] ALL Consulting, 2011, Exhibit19B.
[12] Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[13] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[14] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-6 – Well Drilling – Four-Well Pad GHG Emissions

	Four-Well Pad					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[15]	9,192	NA	NA	NA	104	NA
Power Engines[16]	NA	1,200 hours	1	NA	672	NA
Circulating System[17]	NA	1,200 hours	1	negligible	NA	negligible
Well Control System[18]	NA	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	NA	negligible	776	negligible

[15] ALL Consulting, 2011, Exhibit19B.
[16] Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[17] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[18] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-7 – Well Completion – Single Vertical Well GHG Emissions

	Single Vertical Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours or Fuel Use**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[19]	818	NA	1	NA	9	NA
Hydraulic Fracturing Pump Engines	NA	4,833 gallons[20]	1	NA	54	NA
Line Heater	NA	72 hours	1	NA	negligible	NA
Flowback Pits/Tanks	NA	72 hours	1	NA	NA	negligible
Flare Stack[21]	NA	72 hours	1	12[22]	1,728[23]	NA
Rig Engines[24]	NA	12 hours	1	NA	4	NA
Site Reclamation[25]	NA	24 hours	NA	NA	6	NA
Transportation for Site Reclamation[26]	280	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	12	1,804	negligible

[19] ALL Consulting, 2011, Exhibit 20B.
[20] ALL Consulting, 2009. *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* Table 11, p. 10. Assumed vertical job is one-sixth of high-volume job.
[21] Assumed no use of reduced emission completion ("REC").
[22] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28. . Vertical well not likely to produce at assumed rate due to reduced completion interval.
[23] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28. Vertical well not likely to produce at assumed rate due to reduced completion interval.
[24] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[25] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[26] ALL Consulting, 2011, Exhibit 20B.

Table GHG-8 – Well Completion – Single Horizontal Well GHG Emissions

	Single Horizontal Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours or Fuel Use**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[27]	2,462	NA	1	NA	28	NA
Hydraulic Fracturing Pump Engines	NA	29,000 gallons[28]	1	NA	325	NA
Line Heater	NA	72 hours	1	NA	negligible	NA
Flowback Pits/Tanks	NA	72 hours	1	NA	NA	negligible
Flare Stack[29]	NA	72 hours	1	12[30]	1,728[31]	NA
Rig Engines[32]	NA	24 hours	1	NA	7	NA
Site Reclamation[33]	NA	24 hours	NA	NA	6	NA
Transportation for Site Reclamation[34]	280	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	12	2,097	negligible

[27] ALL Consulting, 2011, Exhibit 19B.
[28] ALL Consulting, 2009. *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* Table 11, p. 10.
[29] Assumed no use of reduced emission completion ("REC").
[30] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28.
[31] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28.
[32] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[33] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[34] ALL Consulting, 2011, Exhibit 19B.

Table GHG-9 – Well Completion – Four-Well Pad GHG Emissions

	Four-Well Pad					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours or Fuel Use**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[35]	9,848	NA	NA	NA	112	NA
Hydraulic Fracturing Pump Engines	NA	116,000 gallons	NA	NA	1,300	NA
Line Heater	NA	288 hours	1	NA	negligible	NA
Flowback Pits/Tanks	NA	288 hours	1	NA	NA	negligible
Flare Stack[36]	NA	288 hours	1	48	6,912	NA
Rig Engines[37]	NA	96 hours	1	NA	28	NA
Site Reclamation[38]	NA	24 hours	NA	NA	6	NA
Transportation for Site Reclamation	280	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	48	8,361	negligible

[35] ALL Consulting, 2011, Exhibit 19B.
[36] Assumed no use of reduced emission completion ("REC").
[37] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[38] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

Table GHG-10 – First-Year Well Production – Single Vertical Well GHG Emissions[39]

	Single Vertical Well					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Production Equipment 10 Truckloads[40]	400	NA	NA	NA	1	NA
Wellhead	NA	8,376 hours[41]	1	NA	NA	negligible
Compressor	NA	8,376 hours	1	not determined	5,883[42] (&4[43])	123[44]
Line Heater	NA	8,376 hours	1	negligible	negligible	negligible
Separator	NA	8,376 hours		NA	negligible	negligible
Glycol Dehydrator	NA	8,376 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	8,376 hours	1	22[45]	3[46]	negligible
Dehydrator Pumps	NA	8,376 hours	1	80[47]	NA	negligible
Pneumatic Device Vents	NA	8,376 hours	3	9[48]	NA	negligible
Meters/Piping	NA	8,376 hours	1	NA	NA	negligible
Vessel BD	NA	4 hours	4	negligible	NA	negligible
Compressor BD	NA	4 hours	4	negligible	NA	negligible
Compressor Starts	NA	4 hours	4	negligible	NA	negligible
Pressure Relief Valves	NA	4 hours	5	negligible	NA	negligible
Production Brine Tanks	NA	8,376 hours	1	negligible	NA	negligible
Production Brine Removal 44Truckloads[49]	1,760	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	111	5,894	123

[39] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well. However, vertical well not likely to produce at assumed rate due to reduced completion interval.
[40] Assumed roundtrip of 40 miles.
[41] Calculated by subtracting total time required to drill and complete one vertical well (16 days) from 365 days.
[42] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[43] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[44] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[45] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[46] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[47] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[48] Emissions Factor (EF) of 0.664 lbs per hour.
[49] Assumed roundtrip of 40 miles.

Table GHG-11 – First-Year Well Production – Single Horizontal Well GHG Emissions[50]

	Single Horizontal Well					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Production Equipment 10 Truckloads[51]	400	NA	NA	NA	1	NA
Wellhead	NA	7,944 hours[52]	1	NA	NA	negligible
Compressor	NA	7,944 hours	1	not determined	5,580[53] (&4[54])	122[55]
Line Heater	NA	7,944 hours	1	negligible	negligible	negligible
Separator	NA	7,944 hours		NA	negligible	negligible
Glycol Dehydrator	NA	7,944 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	7,944 hours	1	21[56]	3[57]	negligible
Dehydrator Pumps	NA	7,944 hours	1	76[58]	NA	negligible
Pneumatic Device Vents	NA	7,944 hours	3	9[59]	NA	negligible
Meters/Piping	NA	7,944 hours	1	NA	NA	negligible
Vessel BD	NA	4 hours	4	negligible	NA	negligible
Compressor BD	NA	4 hours	4	negligible	NA	negligible
Compressor Starts	NA	4 hours	4	negligible	NA	negligible
Pressure Relief Valves	NA	4 hours	5	negligible	NA	negligible
Production Brine Tanks	NA	7,944 hours	1	negligible	NA	negligible
Production Brine Removal 44Truckloads[60]	1,760	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	106	5,591	122

[50] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well.
[51] Assumed roundtrip of 40 miles.
[52] Calculated by subtracting total time required to drill and complete one horizontal well (34 days) from 365 days.
[53] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[54] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[55] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[56] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[57] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[58] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[59] Emissions Factor (EF) of 0.664 lbs per hour.
[60] Assumed roundtrip of 40 miles.

Table GHG-12 – First-Year Well Production – Four-Well Pad GHG Emissions[61]

	Four-Well Pad					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Production Equipment 10 Truckloads[62]	1,600	NA	NA	NA	3	NA
Wellhead	NA	5,496 hours[63]	1	NA	NA	negligible
Compressor	NA	5,496 hours	1	not determined	3,860[64] (&3[65])	80[66]
Line Heater	NA	5,496 hours	1	negligible	negligible	negligible
Separator	NA	5,496 hours		NA	negligible	negligible
Glycol Dehydrator	NA	5,496 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	5,496 hours	1	58[67]	8[68]	negligible
Dehydrator Pumps	NA	5,496 hours	1	210[69]	NA	negligible
Pneumatic Device Vents	NA	5,496 hours	3	6[70]	NA	negligible
Meters/Piping	NA	5,496 hours	4	NA	NA	negligible
Vessel BD	NA	16 hours	8	negligible	NA	negligible
Compressor BD	NA	16 hours	8	negligible	NA	negligible
Compressor Starts	NA	16 hours	8	negligible	NA	negligible
Pressure Relief Valves	NA	16 hours	10	negligible	NA	negligible
Production Brine Tanks	NA	5,496 hours	2	negligible	NA	negligible
Production Brine Removal 176 Truckloads[71]	7,040	NA	NA	NA	11	NA
Total Emissions	NA	NA	NA	274	3,885	80

[61] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well.
[62] Assumed roundtrip of 40 miles.
[63] Calculated by subtracting total time required to drill and complete four horizontal wells (136 days) from 365 days.
[64] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[65] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[66] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[67] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[68] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[69] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[70] Emissions Factor (EF) of 0.664 lbs per hour.
[71] Assumed roundtrip of 40 miles.

Table GHG-13 – Post-First Year Annual Well Production – Single Vertical or Single Horizontal Well GHG Emissions[72]

	Single Vertical Well or Single Horizontal Well					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Wellhead	NA	8,760 hours[73]	1	NA	NA	negligible
Compressor	NA	8,760 hours	1	not determined	6,153[74] (&5[75])	128[76]
Line Heater	NA	8,760 hours	1	negligible	negligible	negligible
Separator	NA	8,760 hours		NA	negligible	negligible
Glycol Dehydrator	NA	8,760 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	8,760 hours	1	23[77]	3[78]	negligible
Dehydrator Pumps	NA	8,760 hours	1	84[79]	NA	negligible
Pneumatic Device Vents	NA	8,760 hours	3	9[80]	NA	negligible
Meters/Piping	NA	8,760 hours	1	NA	NA	negligible
Vessel BD	NA	4 hours	4	negligible	NA	negligible
Compressor BD	NA	4 hours	4	negligible	NA	negligible
Compressor Starts	NA	4 hours	4	negligible	NA	negligible
Pressure Relief Valves	NA	4 hours	5	negligible	NA	negligible
Production Brine Tanks	NA	8,760 hours	1	negligible	NA	negligible
Production Brine Removal 50Truckloads[81]	2,000	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	116	6,164	128

[72] Assumed production 10 mmcfd per well.
[73] Hours in 365 days.
[74] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[75] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[76] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[77] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[78] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[79] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[80] Emissions Factor (EF) of 0.664 lbs per hour.
[81] Assumed roundtrip of 40 miles.

Table GHG-14 – Post-First Year Annual Well Production – Four-Well Pad GHG Emissions[82]

	Four-Well Pad					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Wellhead	NA	8,760 hours[83]	1	NA	NA	negligible
Compressor	NA	8,760 hours	1	not determined	6,153[84] (&5[85])	128[86]
Line Heater	NA	8,760 hours	1	negligible	negligible	negligible
Separator	NA	8,760 hours		NA	negligible	negligible
Glycol Dehydrator	NA	8,760 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	8,760 hours	1	93[87]	12[88]	negligible
Dehydrator Pumps	NA	8,760 hours	1	335[89]	NA	negligible
Pneumatic Device Vents	NA	8,760 hours	3	9[90]	NA	negligible
Meters/Piping	NA	8,760 hours	4	NA	NA	negligible
Vessel BD	NA	16 hours	8	negligible	NA	negligible
Compressor BD	NA	16 hours	8	negligible	NA	negligible
Compressor Starts	NA	16 hours	8	negligible	NA	negligible
Pressure Relief Valves	NA	16 hours	10	negligible	NA	negligible
Production Brine Tanks	NA	8,760 hours	2	negligible	NA	negligible
Production Brine Removal 200Truckloads[91]	8,000	NA	NA	NA	13	NA
Total Emissions	NA	NA	NA	437	6,183	128

[82] Assumed production 10 mmcfd per well.
[83] Hours in 365 days.
[84] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[85] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[86] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[87] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[88] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[89] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[90] Emissions Factor (EF) of 0.664 lbs per hour.
[91] Assumed roundtrip of 40 miles.

Table GHG-15 – Estimated First-Year Green House Gas Emissions from Single Vertical Well

	Single Vertical Well			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)**[92]	**Total Emissions from Proposed Activity CO_2e (tons)**
Drilling Rig Mobilization, Site Preparation and Demobilization	447	NA	NA	447
Completion Rig Mobilization and Demobilization	432	NA	NA	432
Well Drilling	83	negligible	negligible	83
Well Completion including Hydraulic Fracturing and Flowback	1,804	12	300	2,104
Well Production	5,894	234	5,850	11,744
Total	8,660	246	6,150	14,810

Table GHG-16 – Estimated First-Year Green House Gas Emissions from Single Horizontal Well

	Single Horizontal Well			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)**[93]	**Total Emissions from Proposed Activity CO_2e (tons)**
Drilling Rig Mobilization, Site Preparation and Demobilization	447	NA	NA	447
Completion Rig Mobilization and Demobilization	432	NA	NA	432
Well Drilling	194	negligible	negligible	194
Well Completion including Hydraulic Fracturing and Flowback	2,097	12	300	2,397
Well Production	5,591	228	5,700	11,291
Total	8,761	240	6,000	14,761

Table GHG-17 – Estimated Post First-Year Annual Green House Gas Emissions from Single Vertical Well or Single Horizontal Well

	Single Vertical Well or Single Horizontal Well[94]			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)**[95]	**Total Emissions from Proposed Activity CO_2e (tons)**
Well Production	6,164	244	6,100	12,264

[92] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[93] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[94] Assumed production 10 mmcfd per well. However, vertical well not likely to produce at assumed rate due to reduced completion interval, and therefore emission estimates are conservative for vertical well production.
[95] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Table GHG-18 – Estimated First-Year Green House Gas Emissions from Four-Well Pad

	Four-Well Pad			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[96]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Drilling Rig Mobilization, Site Preparation and Demobilization	447	NA	NA	447
Completion Rig Mobilization and Demobilization	432	NA	NA	432
Well Drilling	776	negligible	negligible	776
Well Completion including Hydraulic Fracturing and Flowback	8,361	48	1,200	9,561
Well Production	3,885	354	8,850	12,735
Total	13,901	402	10,050	23,951

Table GHG-19 – Estimated Post First-Year Annual Green House Gas Emissions from Four-Well Pad

	Four-Well Pad			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[97]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Well Production	6,183	565	14,125	20,300

[96] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[97] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

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Part B

Sample Calculations for Combustion Emissions from Mobile Sources

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Sample Calculation for Combustion Emissions (CO_2) from Mobile Sources[1]

INPUT DATA: A fleet of heavy-duty (HD) diesel trucks travels 70,000 miles during the year. The trucks are equipped with advance control systems.

CALCULATION METHODOLOGY:

The fuel usage of the fleet is unknown, so the first step in the calculation is to convert from miles traveled to a volume of diesel fuel consumed basis. This calculation is performed using the default fuel economy factor of 7 miles/gallon for diesel heavy trucks provided API's Table 4-10.

$$70{,}000\,\frac{miles}{project} \times \frac{gallon\ diesel}{7\ miles} = 10{,}000\ \frac{gallons\ diesel\ consumed}{project\ move}$$

Carbon dioxide emissions are estimated using a fuel-based factor provided in API's Table 4-1. This factor is provided on a heat basis, so the fuel consumption must be converted to an energy input basis. This conversion is carried out using a recommended diesel heating value of 5.75×10^6 Btu/bbl (HHV), given in Table 3-5 of this document. Thus, the fuel heat rate is:

$$10{,}000\,\frac{gallons}{project\ move} \times \frac{bbl}{42\ gallons} \times \frac{5.75\ x\ 10^6\ Btu}{bbl} = 1{,}369{,}047{,}619\,\frac{Btu}{project\ move}(HHV)$$

According to API's Table 4-1, the fuel basis CO_2 emission factor for diesel fuel (diesel oil) is 0.0742 tonne $CO_2/10^6$ Btu (HHV basis).

Therefore, CO_2 emissions are calculated as follows, assuming 100% oxidation of fuel carbon to CO_2:

$$1{,}369{,}047{,}619\,\frac{Btu}{project\ move} \times 0.0742\ \frac{tonne\ CO2}{10^6}Btu = 101.78\ \frac{tonnes\ CO2}{project\ move}$$

To convert tonnes to US short tons:

$$101.78\ tonnes \times 2204.62\,\frac{lbs}{tonne} \div 2000\,\frac{lbs}{short\ ton} = 112.19\ tons\,\frac{CO2}{project\ move}$$

[1] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005. pp. 4-39, 4-40.

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Appendix 20

PROPOSED
Pre-Frac Checklist and Certification

Updated July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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PRE-FRAC CHECKLIST AND CERTIFICATION

Well Name and Number:
(as shown on the Department-issued well permit)

API Number:

Well Owner:

Planned Frac Commencement Date:

Yes	No	
☐	☐	Well drilled, cased and cemented in accordance with well permit, or in accordance with revisions approved by the Regional Mineral Resources Manager on the dates listed below and revised wellbore schematic filed in regional Mineral Resources office. Approval Date & Brief Description of Approved Revision(s) *(attach additional sheets if necessary)*
☐	☐	All depths where fresh water, brine, oil and/or gas were encountered or circulation was lost during drilling operations are recorded on the attached sheet. Additional sheets are attached which describe how any lost circulation zones were addressed.
☐	☐	Enclosed radial cement bond evaluation log and narrative analysis of such, or other Department-approved evaluation, and consideration of appropriate supporting data per Section 6.4 "Other Testing and Information" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009) verifies top of cement and effective cement bond at least 500 feet above the top of the formation to be fractured or at least 300 feet into the previous casing string. If intermediate casing was not installed, or if was not production casing was not cemented to surface, then provide the date of approval by the Department and a brief description of justification. Approval Date & Brief Description of Justification *(attach additional sheets if necessary)*
☐	☐	Per Section 7.1 "General" under the heading "Well Construction Guidelines" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009), a representative blend of the cement used for the production casing was bench tested in accordance with API 10A Specification for Cements and Materials for Well Cementing (Twenty-Fourth Edition, December 2010) and was found to be of sufficient strength to withstand the maximum anticipated treatment pressure during hydraulic fracturing operations.
☐	☐	If fracturing operations will be performed down casing, then the pre-fracturing pressure tests required by permit conditions will be conducted and fracturing operations will only commence if the tests are successful. Any unsuccessful test will be reported to the Department and remedial measures will be proposed by the operator and must be approved by the Department prior to further operations.

☐ ☐ All other information collected while drilling, listed below, verifies that all observed gas zones are isolated by casing and cement and that the well is properly constructed and suitable for high-volume hydraulic fracturing.

Date and Brief Description of Information Collected
(attach additional sheets if necessary)

☐ ☐ Fracturing products used will be the same products identified in the well permit application materials or otherwise identified and approved by the Department.

I hereby affirm under penalty of perjury that information provided on this form is true to the best of my knowledge and belief. False statements made herein are punishable as a Class A misdemeanor pursuant to Section 210.45 of the Penal Law.

Printed or Typed Name and Title of Authorized Representative
Signature, Date

INSTRUCTIONS FOR PRE-FRAC CHECKLIST AND CERTIFICATION

The completed and signed form, and treatment plan must be received by the appropriate Regional office at least 3 days prior to the commencement of hydraulic fracturing operations. The treatment plan must include a profile showing anticipated pressures and volume of fluid for pumping the first stage. It must also include a description of the planned treatment interval for the well (i.e., top and bottom of perforations expressed in both True Vertical Depth (TVD) and True Measured Depth (TMD)). The operator may conduct hydraulic fracturing operations provided 1) all items on the checklist are affirmed by a response of "Yes," 2) the *Pre-Frac Checklist And Certification*, and treatment plan are received by the Department at least 3 days prior to hydraulic fracturing and 3) all other pre-frac notification requirements are met as specified elsewhere. **The well owner is prohibited from conducting hydraulic fracturing operations on the well without additional Department review and approval if a response of "No" is provided to any of the items in the pre-frac checklist.**

SIGNATURE SECTION

Signature Section - The person signing the *Pre-Frac Checklist And Certification* must be authorized to do so on the Organizational Report on file with the Division of Mineral Resources.

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Appendix 21

Publically Owned Treatment Works (POTWs) With Approved Pretreatment Programs

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Supplemental Generic Environmental Impact Statement

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Pretreatment Facilities and Associated WWTPs

Region	Pretreatment Program	Facility	SPDES Number
1	Nassau County DPW - this facility is tracked under Cedar Creek in PCS.	Inwood STP Bay Park STP ***Cedar Creek WPCP	NY0026441 NY0026450 NY0026859
	Glen Cove (C)	Glen Cove STP	NY0026620
	Suffolk DPW	Suffolk Co. SD #3 - Southwest	NY0104809
2	New York City DEP	Wards Island WPCP Owls Head WPCP Newtown Creek WPCP Jamaica WPCP North River WPCP 26th Ward WPCP Coney Island WPCP Red Hook WPCP Tallman Island WPCP Bowery Bay WPCP Rockaway WPCP Oakwood Beach WPCP Port Richmond WPCP Hunts Point WPCP	NY0026131 NY0026166 NY0026204 NY0026115 NY0026247 NY0026212 NY0026182 NY0027073 NY0026239 NY0026158 NY0026221 NY0026174 NY0026107 NY0026191
3	Suffern (V)	Suffern	NY0022748
	Orangetown SD #2		NY0026051
	Orange County SD #1	Harriman STP	NY0027901
	Newburgh (C)	Newburgh WPCF	NY0026310
	Westchester County	Blind Brook Mamaroneck New Rochelle Ossining Port Chester Peekskill Yonkers Joint	NY0026719 NY0026701 NY0026697 NY0108324 NY0026786 NY0100803 NY0026689
	Rockland County SD #1		NY0031895
	Poughkeepsie (C)	Poughkeepsie STP	NY0026255
	New Windsor (T)	New Windsor STP	NY0022446
	Beacon (C)	Beacon STP	NY0025976
	Haverstraw Joint Regional Sewer Board	Haverstraw Joint Regional Stp	NY0028533
	Kingston (C)	Kingston (C) WWTF	NY0029351
4	Amsterdam (C)	Amsterdam STP	NY0020290
	Albany County	North WWTF South WWTF	NY0026875 NY0026867
	Schenectady (C)	Schenectady WPCP	NY0020516
	Rennselaer County SD #1	Rennselaer County SD #1	NY0087971
5	Plattsburgh (C)	City of Plattsburgh WPCP	NY0026018
	Glens Falls (C)	Glens Fall (C)	NY0029050
	Gloversville-Johnstown Joint Board		NY0026042
	Saratoga County SD #1		NY0028240

Region	Pretreatment Program	Facility	SPDES Number
6	Little Falls (C)	Little Falls WWTP	NY0022403
	Herkimer County	Herkimer County SD	NY0036528
	Rome (C)	Rome WPCF	NY0030864
	Ogdensburg (C)	City of Ogdensburg WWTP	NY0029831
	Oneida County		NY0025780
	Watertown		NY0025984
7	Auburn (C)	Auburn STP	NY0021903
	Fulton (C)		NY0026301
	Oswego (C)	Westside Wastewater Facility Eastside Wastewater Facility	NY0029106 NY0029114
	Cortland (C)	LeRoy R. Summerson WTF	NY0027561
	Endicott (V)	Endicott WWTF	NY0027669
	Ithaca (C)		NY0026638
	Binghamton-Johnson City		NY0024414
	Onondaga County	Metropolitan Syracuse Baldwinsville/Seneca Knolls Meadowbrook/Limestone Oak Orchard Wetzel Road	NY0027081 NY0030571 NY0027723 NY0030317 NY0027618
8	Canandaigua (C)	Canandaigua STP	NY0025968
	Webster (T)	Walter W. Bradley WPCP	NY0021610
	Monroe County	Frank E VanLare STP Northwest Quadrant STP	NY0028339 NY0028231
	Batavia (C)		NY0026514
	Geneva (C)	Marsh Creek STP	NY0027049
	Newark (V)		NY0029475
	Chemung County	Chemung County SD #1 Chemung County - Elmira Chemung County - Baker Road	NY0036986 NY0035742 NY0246948
9	Middleport (V)	Middleport (V) STP	NY0022331
	North Tonawanda (C)		NY0026280
	Newfane STP (T)		NY0027774
	Erie County Southtowns	Erie County Southtowns Erie County SD #2 - Big Sister	NY0095401 NY0022543
	Niagara County	Niagara County SD #1	NY0027979
	Blasdell (V)	Blasdell	NY0020681
	Buffalo Sewer Authority	Buffalo (C)	NY0028410
	Amherst SD (T)		NY0025950
	Niagara Falls (C)		NY0026336
	Tonawanda (T)	Tonawanda (T) SD #2 WWTP	NY0026395
	Lockport (C)		NY0027057
	Olean STP (C)		NY0027162
	Jamestown STP (C)		NY0027570
	Dunkirk STP (C)		NY0027961

Mini-Pretreatment Facilities

Region	Facility	SPDES Number
3	Arlington WWTP	NY0026271
3	Port Jervis STP	NY0026522
3	Wallkill (T) STP	NY0024422
4	Canajoharie (V) WWTP	NY0023485
4	Colonie (T) Mohawk View WPCP	NY0027758
4	East Greenbush (T) WWTP	NY0026034
4	Hoosick Falls (V) WWTP	NY0024821
4	Hudson (C) STP	NY0022039
4	Montgomery co SD#1 STP	NY0107565
4	Park Guilderland N.E. IND STP	NY0022217
4	Rotterdam (T) SD2 STP	NY0020141
4	Delhi (V) WWTP	NY0020265
4	Hobart (V) WWTP	NY0029254
4	Walton (V) WWTP	NY0027154
7	Canastota (V) WPCP	NY0029807
7	Cayuga Heights (V) WWTP	NY0020958
7	Moravia (V) WWTP	NY0022756
7	Norwich (C) WWTP	NY0021423
7	Oak Orchard STP	NY0030317
7	Oneida (C) STP	NY0026956
7	Owego (T) SD#1	NY0022730
7	Owego WPCP #2	NY0025798
7	Sherburne (V) WWTP	NY0021466
7	Waverly (V) WWTP	NY0031089
7	Wetzel Road WWTP	NY0027618
8	Avon (V) STP	NY0024449
8	Bath (V) WWTP	NY0021431
8	Bloomfield (V) WWTP	NY0024007
8	Clifton Springs (V) WWTP	NY0020311
8	Clyde (V) WWTP	NY0023965
8	Corning (C) WWTP	NY0025721
8	Dundee STP	NY0025445
8	Erwin (T) WWTP	NY0023906
8	Holley (V) WPCP	NY0023256
8	Honeoye Falls (V) WWTP	NY0025259
8	Hornell (C) WPCP	NY0023647
8	Marion STP	NY0031569
8	Ontario (T) STP	NY0027171
8	Seneca Falls (V) WWTP	NY0033308
8	Walworth SD #1	NY0025704
9	Akron (V) WWTP	NY0031003
9	Arcade (V) WWTP	NY0026948
9	Attica (V) WWTP	NY0021849
9	East Aurora (V) STP	NY0028436
9	Gowanda (V)	NY0032093

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Appendix 22

Publically Owned Treatment Works (POTWs) Procedures for Accepting Wastewater from High-Volume Hydraulic Fracturing

Revised July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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POTW Procedures for Accepting High-Volume Hydraulic Fracturing Wastewater

The following procedure shall be followed when a Publically Owned Treatment Works (POTW) proposes to accept high-volume hydraulic fracturing wastewater from a well driller or other development company. Page 5 of this appendix shows a simplified flowchart of this process. Please note that this disposal option is limited to the extent that municipal POTWs which utilize biological wastewater treatment are generally optimized for the removal of domestic wastewater and as such are not designed to treat several of the contaminants present in high-volume hydraulic fracturing wastewater. In addition to the above concerns, the additional monitoring and laboratory costs which will result from additional monitoring conditions in the permit must also be considered prior to deciding to accept this source of wastewater.

1. The POTW operator receives a request to accept flowback water from a well driller. Prior to submitting this request to the Department for approval, the POTW should review the request to assure that it includes, at a minimum:
    a. The volume of water to be sent to wastewater treatment plant in gallons per unit time (e.g. 25,000 gallons per day);
    b. Whether the discharge is a one-time disposal, or will be an ongoing source of wastewater to the POTW;
    c. A characterization of high-volume hydraulic fracturing wastewater quality including all high-volume hydraulic facturing parameters of concern and NORM analysis;
    d. A characterization of existing POTW wastewater quality including:
        i. Sample results for all high-volume hydraulic fracturing parameters of concern, and
        ii. the results of short term high intensity monitoring for both TDS (in mg/l) and Radium 226 (in piC/l), consisting of the results of ten (10) samples each of existing influent, sludge, and effluent from the POTW.
    e. The source of the wastewater (well name, well developer, Mineral Resources permit number, and location(s) of the wells); and

f. A list of all additives used in the hydraulic fracturing process at the source well(s).

2. The POTW shall forward the above request to the Bureau of Water Permits, 625 Broadway, Albany NY 12233-3505 along with the following supporting information:
   a. Documentation of existing EPA and Departmental approval of the facility's headworks analysis for the acceptance of high-volume hydraulic fracturing wastewater; or a completed headworks analysis for the high-volume hydraulic fracturing specific parameters of concern for Department and USEPA approval;
   b. Demonstration of available POTW capacity to accept the proposed volume of high-volume hydraulic fracturing wastewater; and
   c. Confirmation that the facility has an approved USEPA pretreatment or Department mini-pretreatment program as part of its SPDES permit.

3. The Division of Water will review the submitted information to determine whether the high-volume hydraulic fracturing wastewater source has been adequately characterized. If additional information is necessary, the Division of Water will request additional sampling and source information from the POTW.

4. The Division of Water will review the facility's SPDES permit to determine whether the permit needs to be modified to include high-volume hydraulic fracturing specific monitoring, limits, and reporting conditions.

5. Concurrently with 3. and 4. above, if a headworks analysis for the high-volume hydraulic fracturing specific parameters of concern was submitted for approval, the Division of Water will forward a copy of the headworks analysis to the USEPA Region 2 office for its review and approval. The Division of Water and USEPA Region 2 will review the facility's headworks analysis to assure that the POTW is capable of accepting the proposed volume and quantity of high-volume hydraulic fracturing wastewater

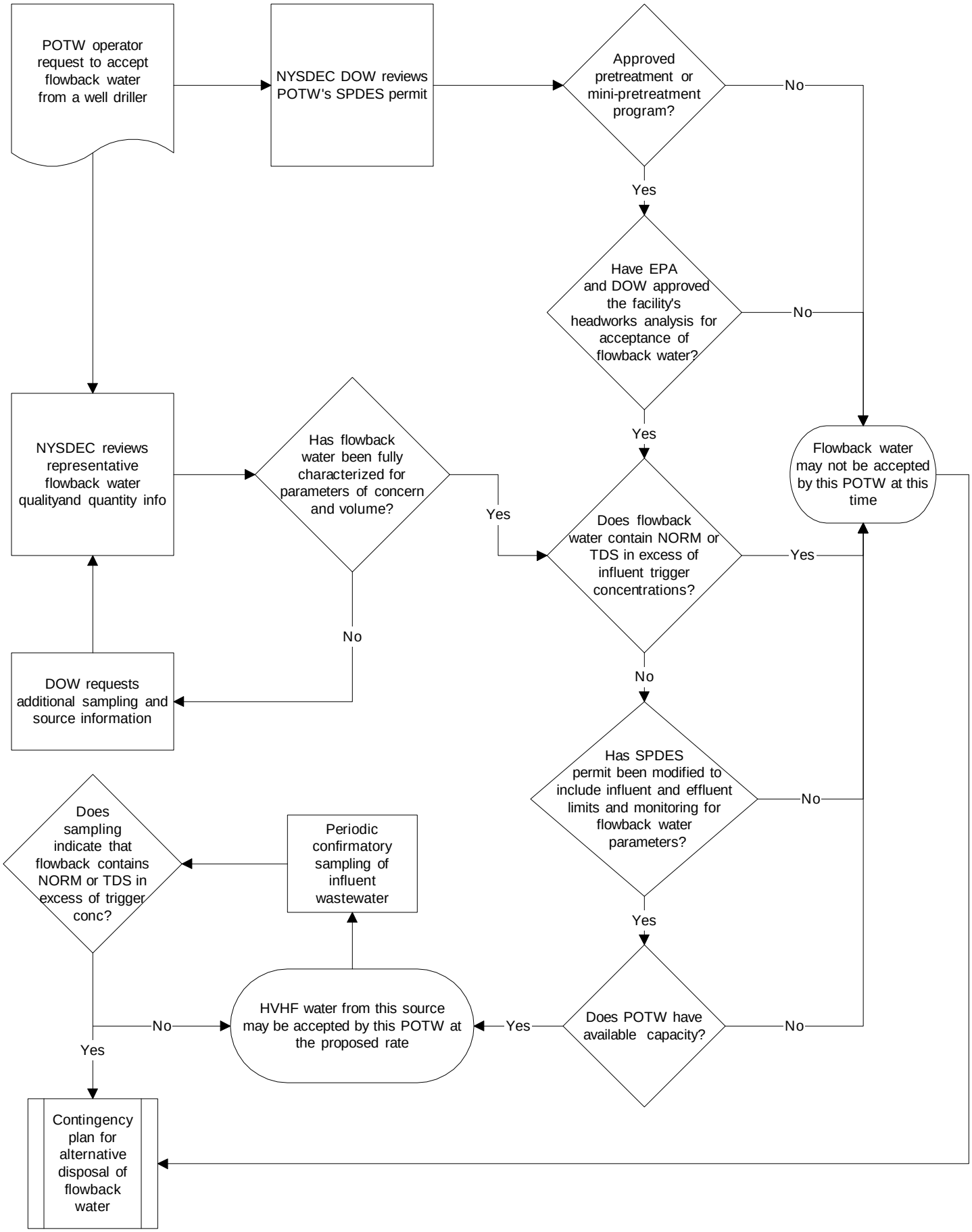
6. The Department will send a determination regarding the request to the permittee following the Division of Water and USEPA's analysis of the request. If the request is approved, the POTW may accept high-volume hydraulic fracturing wastewater from the requested source at the specified maximum concentrations and requested discharge rate following receipt of Departmental approval, which will include the following components:
    a. Approval of submitted headworks analysis by the Department and USEPA; and
    b. SPDES permit modification with high-volume hydraulic fracturing specific monitoring, limits, and reporting conditions, including;
        i. Specification of the source and maximum discharge rate of the high-volume hydraulic fracturing wastewater to be accepted;
        ii. Influent radium-226 and TDS limits;
        iii. Effluent limits and/or monitoring for NORM, TDS, and other high-volume hydraulic fracturing parameters of concern;
        iv. Periodic confirmatory sampling of influent wastewater for high-volume hydraulic fracturing parameters of concern to assure that the characteristics of the influent wastewater have not changed substantially from the characterization provided in the approval request;
        v. periodic sludge sampling to assure that the concentration of radionuclides in the sludge do not exceed 5 piC/g; and
        vi. Any other monitoring conditions necessary to assure that the discharge from the POTW does not cause or contribute to a violation of NYS water quality standards.

7. If the Department does not approve the acceptance of flowback water, a written denial will be sent to the permittee with the reason(s) for denial. These reasons could include, but not be limited to: inadequate receiving water assimilative capacity, NORM concentrations in excess of the applicable influent Radium-226 limit of 15- piC/l, influent concentrations of any other parameters in excess of the levels acceptable in the approved headworks analysis, or inadequate POTW capacity.

8. Following approval and permit modification, the POTW must notify the Department whenever:
    a. The facility wishes to increase the quantity of high-volume hydraulic fracturing wastewater accepted from this source;
    b. The facility wishes to accept any volume of high-volume hydraulic fracturing wastewater from a new or additional source;
    c. The high-volume hydraulic fracturing wastewater contains NORM or TDS in excess of the influent limits for these parameters; or
    d. The facility has decided to stop accepting high-volume hydraulic fracturing wastewater from one or more sources.

The notifications in a. – c. would be treated as a request for a new source of high-volume hydraulic fracturing wastewater, and would be processed in accordance with Items 1-7 above.

Flowchart for acceptance of High Volume Hydraulic Fracturing (HVHF) wastewater by publicly owned treatment works (POTWs)



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Appendix 23

USEPA Natural Gas STAR Program

Revised Draft
Supplemental Generic Environmental Impact Statement

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TO: Peter Briggs, New York State Department of Environmental Conservation, Mineral Resources

FROM: Jerome Blackman, Natural Gas STAR International

DATE: September 1, 2009

RE: Natural Gas Star

This memo lists methane emission mitigation options applicable in exploration and production; in reference to your inquiry. Natural Gas STAR Partners have reported a number of voluntary activities to reduce exploration and production methane emissions, and major project types are listed and summarized below and may help focus your research as you review the resources available on the Natural Gas STAR website.

In addition to these practices and technologies is an article that lists the same and several more cost effective options for producers to reduce methane emissions. Please refer to the link below.

Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers
www.epa.gov/gasstar/documents/CaseStudy.pdf

Reduced Emission Completions
Traditionally, "cleaning up" drilled wells, before connecting them to a production sales line, involves producing the well to open pits or tankage where sand, cuttings, and reservoir fluids are collected for disposal and the produced natural gas is vented to the atmosphere. Partners reported using a "green completion" method in which tanks, separators, dehydrators are brought on site to clean up the gas sufficiently for delivery to sales. The result is reducing completion emissions, creating an immediate revenue stream, and less solid waste.

Partner Recommended Opportunity from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/greencompletions.pdf

BP Experience Presentation with Reduced Emission Completions
www.epa.gov/gasstar/documents/workshops/2008-annual-conf/smith.pdf

Green Completion Presentation from a Tech-Transfer Workshop in 2005 at Houston, TX
www.epa.gov/gasstar/documents/workshops/houston-2005/green_c.pdf

Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrator
In dehydrators, as triethylene glycol (TEG) absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). When the TEG is regenerated through heating, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. Many wells produce gas below the initial design capacity yet

TEG circulation rates remain two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Optimizing circulation rates reduces methane emissions at negligible cost. Installing flash tank separators on glycol dehydrators further reduces methane, VOC, and HAP emissions and saves even more money. Flash tanks can recycle typically vented gas to the compressor suction and/or used as a fuel for the TEG reboiler and compressor engine.

Lessons Learned Document from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_flashtanks3.pdf

Dehydrator Presentation from a 2008 Tech-Transfer Workshop in Charleston, WV:
www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/charleston_dehydration.pdf

Replacing Glycol Dehydrators with Desiccant Dehydrators
Natural Gas STAR Partners have found that replacing glycol dehydrators with desiccant dehydrators reduces methane, VOC, and HAP emissions by 99 percent and also reduces operating and maintenance costs. In a desiccant dehydrator, wet gas passes through a drying bed of desiccant tablets. The tablets pull moisture from the gas and gradually dissolve in the process. Replacing a glycol dehydrator processing 1 million cubic feet per day (MMcfd) of gas with a desiccant dehydrator can save up to $9,232 per year in fuel gas, vented gas, operation and maintenance (O&M) costs, and reduce methane emissions by 444 thousand cubic feet (Mcf) per year.

Lessons Learned Document from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_desde.pdf

Directed Inspection and Maintenance
A directed inspection and maintenance (DI&M) program is a proven, cost-effective way to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions. A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs that are cost-effective to fix are then made to the leaking components. Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair.

Lessons Learned Documents from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_dimgasproc.pdf
www.epa.gov/gasstar/documents/ll_dimcompstat.pdf

Partner Recommended Opportunity from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/conductdimatremotefacilities.pdf

DI&M Presentation from a Tech-Transfer Workshop in 2008 at Midland, TX
www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/midland4.ppt

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Appendix 24

Key Features of the USEPA Natural Gas STAR Program

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Key Features of USEPA Natural Gas STAR Program[1]

Complete information on the Natural Gas STAR Program is given in USEPA's web site (http://epa.gov/gasstar/index.html)

- Participation in the program is voluntary.
- Program outreach is provided through the web site, annual national two-day implementation workshop, and sector– or activity – specific technology transfer workshops or webcasts, often with a regional focus (approximately six to nine per year).
- Companies agreeing to join ("Partners") commit to evaluating Best Management Practices (BMP) and implementing them when they are cost-effective for the company. In addition, " …partners are encouraged to identify, implement, and report on other technologies and practices to reduce methane emissions (referred to as Partner Reported Opportunities or PROs)."
- Best Management Practices are a limited set of reduction measures identified at the initiation of the program as widely applicable. PROs subsequently reported by partners have increased the number of reduction measures.
- The program provides calculation tools for estimating emissions reductions for BMPs and PROs, based on the relevant features of the equipment and application.
- Projected emissions reductions for some measures can be estimated accurately and simply; for example, reductions from replacing high-bleed pneumatic devices with low-bleed devices are a simple function of the known bleed rates of the respective devices, and the methane content of the gas. For others, such as those involving inspection and maintenance to detect and repair leaks, emissions reductions are difficult to anticipate because the number and magnitude of leaks is initially unknown or poorly estimated.
- Tools are also provided for estimating the economics of emission reduction measures, as a function of factors such as gas value, capital costs, and operation and maintenance costs.
- Technical feasibility is variable between measures and is often site- or application- specific. For example, in the Gas STAR Lessons Learned for replacing high-bleed with low-bleed pneumatic devices, it is estimated that "nearly all" high-bleed devices can feasibly be replaced with low-bleed devices. Some specific exceptions are listed, including very large valves requiring fast and/or precise response, commonly on large compressor discharge and bypass controllers.
- Partners report emissions reductions annually, but the individual partner reports are confidential. Publicly reported data are aggregated nationally, but include total reductions by sector and by emissions reduction measure.

[1] New Mexico Environment Department, *Oil and Gas Greenhouse Gas Emissions Reductions*. December 2007, pp. 19-20.

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Appendix 25

Reduced Emissions Completion (REC) Executive Summary

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Reduced Emissions Completions – Executive Summary[1]

High prices and high demand for natural gas, have seen the natural gas production industry move into development of the more technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane. Completion of new wells and re-working (workover) of existing wells in these tight formations typically involves hydraulic fracturing of the reservoir to increase well productivity. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and methane emissions to the atmosphere.

Conventional completion of wells (a process that cleans the well bore of stimulation fluids and solids so that the gas has a free path from the reservoir) results in gas being either vented or flared. Vented gas results in large amounts of methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) emissions to the atmosphere while flared gas results in carbon dioxide emissions.

Reduced emissions completion (REC) – also known as reduced flaring completion – is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids so that the gas is suitable for injection into the sales pipeline. Reduced emissions completions help to mitigate methane, VOC, and HAP emissions during the well flowback phase and can eliminate or significantly reduce the need for flaring.

RECs have become a popular practice among Natural Gas STAR production partners. A total of eight different partners have reported performing reduced emissions completions in their operations. RECs have become a major source of methane emission reductions since 2000. Between 2000 and 2005 emissions reductions from RECs have increased from 200 MMcf to over 7,000 MMcf. This represents additional revenue from natural gas sales of over $65 million in 2005 (assuming $7/Mcf gas prices).

Method for Reducing Gas Loss	**Volume of Natural Gas Savings (Mcf/yr)[1]**	**Value of Natural Gas Savings ($/yr)[2]**	**Additional Savings ($/yr)[3]**	**Set-up Costs ($/yr)**	**Equipment Rental and Labor Costs ($)**	**Other Costs ($/yr)[4]**	**Payback (Months)[5]**
Reduced Emissions Completion	270,000	1,890,000	197,500	15,000	212,500	129,500	3

1. Based on an annual REC program of 25 completions per year
2. Assuming $7/Mcf gas
3. Savings from recovering condensate and gas compressed to lift fluids
4. Cost of gas used to fuel compressor and lift fluids
5. Time required to recover the entire annual cost of the program

[1]Adapted from ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, *Task 2 – Technical Analysis of Potential Impacts to Air*, Agreement No. 9679, August 2009. Appendix 2.1.

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Appendix 26

Instructions for Using The On-Line Searchable Database to Locate Drilling Applications

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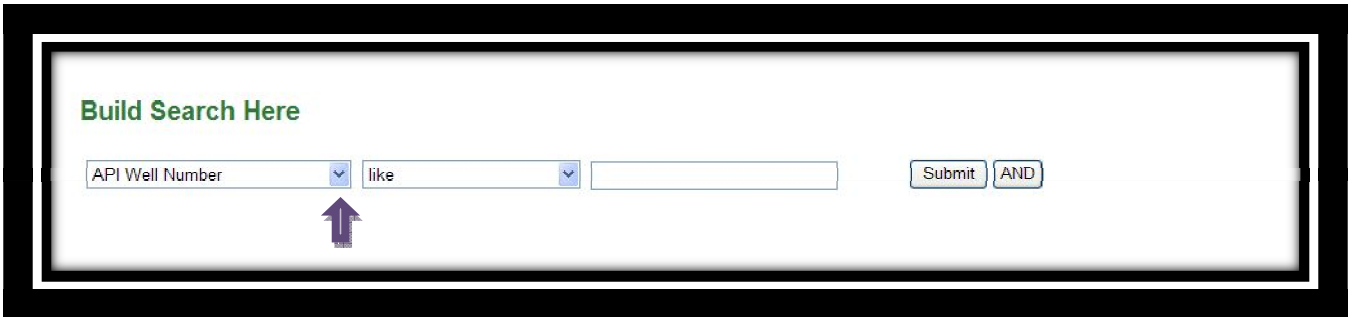
How to Use the Online Searchable Database to Find Information about Recently Filed Permit Applications

The online searchable database can be found at http://www.dec.ny.gov/cfmx/extapps/GasOil/. It is a very user friendly program and can be used to conduct both simple and complex searches.

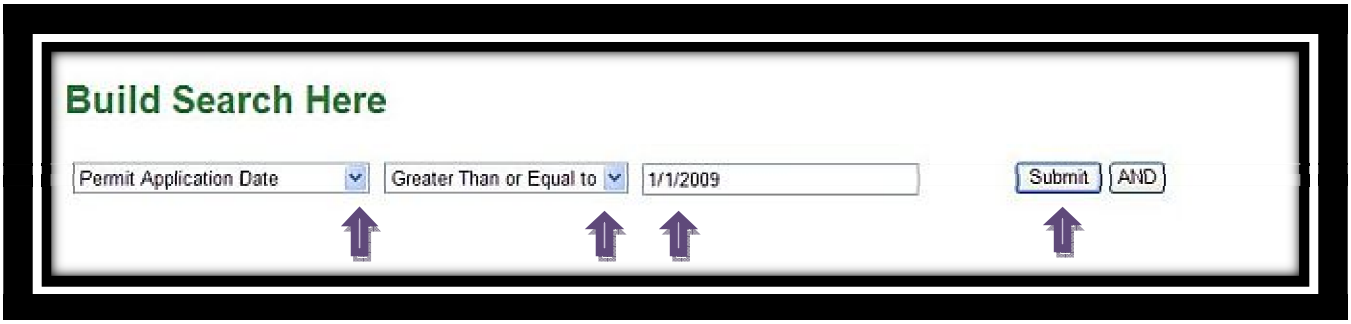
How to Conduct a Simple Search

1. Select Wells Data to begin your search.

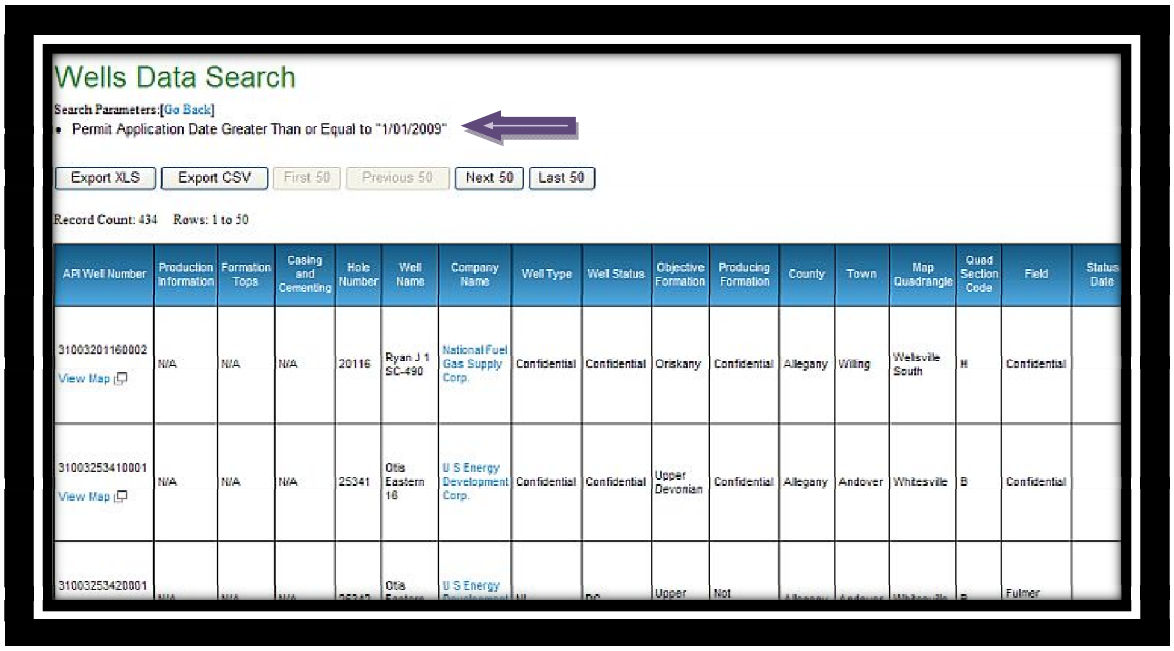
2. Select your search criteria. Use the drop down arrow next to API Number to select your search criteria.



3. To find a new permit application, enter Permit Application Date is Greater Than or Equal to, and the date that you would like to search from. Enter Permit Application Data is Greater Than or Equal to 1/1/year to find all permit applications filed during a specific year. Click the Submit button.



4. View results. By selecting the View Map hyperlink, a new window will open to Google Maps showing the well location along with latitude and longitude information. The results from your query can be saved to your computer as either an Excel spreadsheet (xls) or as a comma separated value file (csv) by clicking the appropriate Export button at the bottom the results screen. Clicking a hyperlink in the Company Name column will provide contact information for the company.



Wells Data Search

Search Parameters:[Go Back]

- Permit Application Date Greater Than or Equal to "1/01/2009"

Export XLS | Export CSV | First 50 | Previous 50 | Next 50 | Last 50

Record Count: 434 Rows: 1 to 50

API Well Number	Production Information	Formation Tops	Casing and Cementing	Hole Number	Well Name	Company Name	Well Type	Well Status	Objective Formation	Producing Formation	County	Town	Map Quadrangle	Quad Section Code	Field	Status Date
31003201160002 View Map	N/A	N/A	N/A	20116	Ryan J 1 SC-490	National Fuel Gas Supply Corp.	Confidential	Confidential	Oriskany	Confidential	Allegany	Willing	Wellsville South	H	Confidential	
31003253410001 View Map	N/A	N/A	N/A	25341	Otis Eastern 16	U S Energy Development Corp.	Confidential	Confidential	Upper Devonian	Confidential	Allegany	Andover	Whitesville	B	Confidential	
31003253420001	N/A	N/A	N/A	25342	Otis Eastern	U S Energy Development	[illegible]	[illegible]	Upper	Not	[illegible]	[illegible]	[illegible]	[illegible]	Fulmer	

How to Narrow or Expand Your Search Utilizing the AND Button

1. Select Wells Data to begin your search.

Search Database

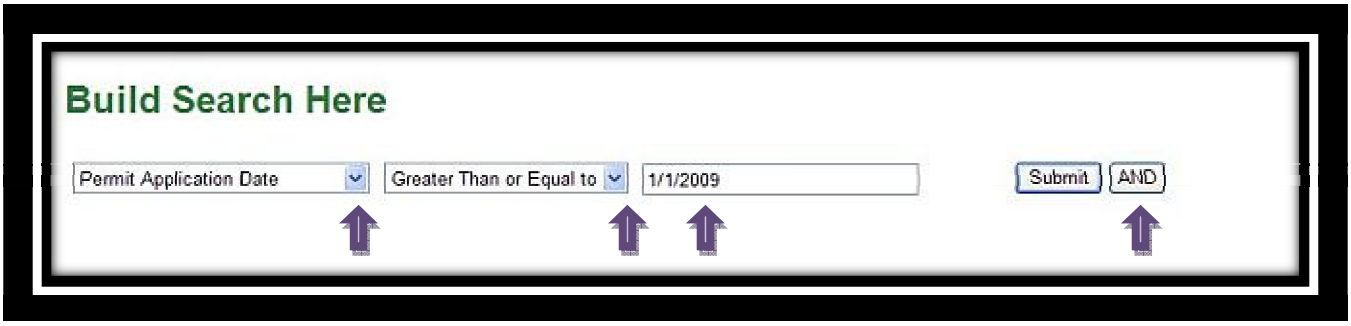
- General Search Tips/Help
- Set User Preferences
- Company Data
- Wells Data
- Annual Well Production
- Well Transfers
- Geologic Formation
- Geologic Fields

For more information:

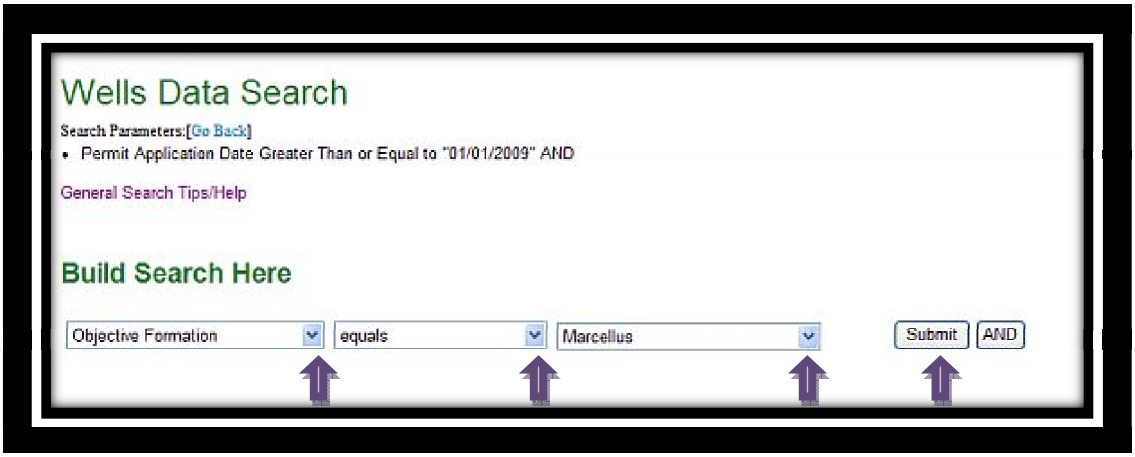
Division of Mineral Resources

Environmental Notice Bulletin for Minerals

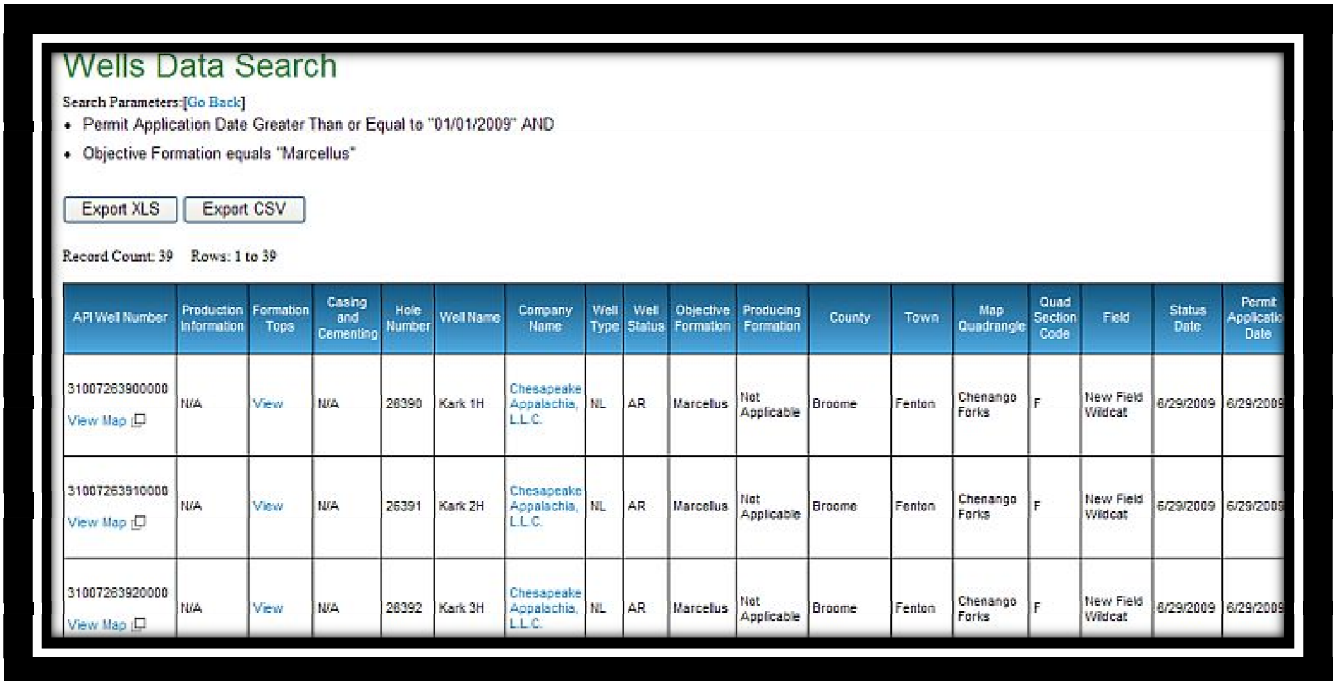
2. Select your search criteria. To find all permit applications filed in 2009 that target a specific geologic formation, select Permit Application Date is Greater Than or Equal to 1/1/2009. Click the AND button.



3. Select your next set of search criteria. To find all permit applications filed in 2009 for the Marcellus formation, select Objective Formation equals Marcellus. Click the Submit button.



4. View Results.

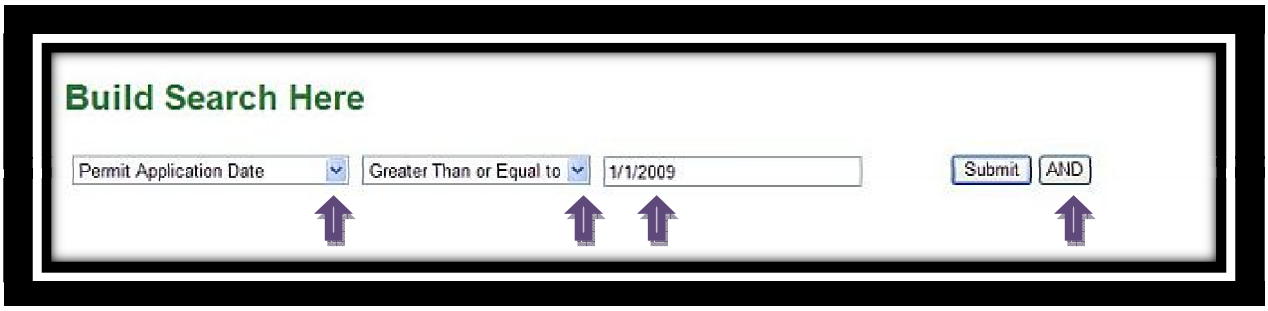


API Well Number	Production Information	Formation Tops	Casing and Cementing	Hole Number	Well Name	Company Name	Well Type	Well Status	Objective Formation	Producing Formation	County	Town	Map Quadrangle	Quad Section Code	Field	Status Date	Permit Applicatio Date
31007263900000 View Map	N/A	View	N/A	26390	Kark 1H	Chesapeake Appalachia, L.L.C.	NL	AR	Marcellus	Not Applicable	Broome	Fenton	Chenango Forks	F	New Field Wildcat	6/29/2009	6/29/2009
31007263910000 View Map	N/A	View	N/A	26391	Kark 2H	Chesapeake Appalachia, L.L.C.	NL	AR	Marcellus	Not Applicable	Broome	Fenton	Chenango Forks	F	New Field Wildcat	6/29/2009	6/29/2009
31007263920000 View Map	N/A	View	N/A	26392	Kark 3H	Chesapeake Appalachia, L.L.C.	NL	AR	Marcellus	Not Applicable	Broome	Fenton	Chenango Forks	F	New Field Wildcat	6/29/2009	6/29/2009

How to Narrow Your Search to Applications Submitted For a Specific County

1. Select Wells Data to begin your search.

2. Select your search criteria. To find all permit applications filed in 2009 in a specific county, select Permit Application Date is Greater Than or Equal to 1/1/2009. Click the AND button.



3. Select your next set of search criteria. To find all permits applied for in 2009 in Allegany County, select County equals Allegany. Click the Submit button.

New York State

DEC

Appendix 27

NYSDOH Radiation Survey Guidelines and Sample Radioactive Materials Handling License

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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Radiological Survey Requirements

I. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

II. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

III. Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

IV. Survey Frequency

Radiological survey data must be conducted within 6 months following the start of gas production and at intervals not to exceed 12 months thereafter.

The permit tee must conduct surveys of all equipment used on the production train prior to disposal, recycling or transfer to any entity.

Equipment that exceeds 50microrem/hr is subject licensure by the New York State Department of Health.

V. Survey data reports

Survey data must be submitted within 30 days following the survey, and must contain the information required by Section III.

NEW YORK STATE
DEPARTMENT OF HEALTH
BUREAU OF ENVIRONMENTAL RADIATION PROTECTION

Radiation Guide 1.15

GUIDE FOR APPLICATION TO POSSESS NATURALLY OCCURRING RADIOACTIVE MATERIAL (NORM) INCIDENT TO NATURAL GAS INDUSTRY

I. INTRODUCTION

PURPOSE OF GUIDE

The purpose of this regulatory guide is to provide assistance to applicants in preparing applications for new licenses for the possession of naturally occurring radioactive materials (NORM) incident to natural gas exploration and production. This regulatory guide is intended to provide you, the applicant, with information that will enable you to understand specific regulatory requirements and licensing policies as they apply to the license activities proposed.

After you are issued a license, you must conduct your program in accordance with (1) the statements, representations and procedures contained in your application; (2) the terms and conditions of the license; and (3) the Department of Health's regulations in 10 NYCRR 16 and 12 NYCRR 38. The information you provide in your application should be clear, specific and accurate.

II. FILING AN APPLICATION

You, as the applicant for a materials license, must complete Items 1 through 4 and 18 on the attached application form. For other applicable Items, submit the information on supplementary pages. Each separate sheet or document submitted with the application should be identified and keyed to the item number on the application to which it refers. All typed pages, sketches, and, if possible, drawings should be on 8 ½ x 11 inch paper to facilitate handling and review. If larger drawings are necessary, they should be folded to 8 ½ x 11inches. You should complete all items in the application in sufficient detail for the Department to determine that your equipment, facilities, training and experience, and radiation safety program are adequate to protect health and to minimize danger to life and property.

You must submit two copies of your application with attachments. Retain one copy of the application for yourself, because the license will require that you possess and use licensed material in accordance with the statements and representations in your application and in any supplements to it.

Mail your completed application and the required non-refundable triennial fee ($3000) to:

New York State Department of Health
Bureau of Environmental Radiation Protection
Flanigan Square, 547 River Street
Troy, New York 12180

Please Note: Applications received without fees will not be processed .

III. CONTENTS OF AN APPLICATION

Item 1. Name and address.

Enter the name and corporate address of the applicant and the telephone number of company management. The name of the firm must appear exactly as it appears on legal papers authorizing the conduct of business. Indicate if the name and address are different from those listed on the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill.

Item 2A. Addresses at which radioactive material will be used.

List all addresses and locations where radioactive material will be used or stored, i.e., the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill Nos., well name, and town name.

2.B. Not applicable

Item 3. Nature of business

Enter the nature of the business the applicant is engaged in and the name and telephone number (including area code) of the individual to be contacted in connection with this application.

Item 4. Previous radioactive materials license

Enter any previous or current radioactive materials license numbers and identify the issuing agency. Also indicate whether you possess any radioactive material under a general license.

Describe the circumstances of any denial, revocation or suspension of a radioactive materials license previously held.

Item 5. Department to Use Radioactive Material

Not Applicable

Item 6. Individual Users of Radioactive Materials

Not Applicable,

Item 7. Radiation Safety Officer

State the name, title and contact information (phone, fax, and e-mail) of the person designated by, and responsible to, management for the coordination of the radiation safety program. This person will be named on the license as the Radiation Safety Officer. He/she will be responsible to oversee and ensure that licensed radioactive material is possessed in accordance with regulations and the radioactive materials license.

Item 8. Radioactive Material

No response is required. The license will list Naturally Occurring Radioactive Material (NORM).

Item 9. Purpose for which Radioactive Material Will be Used

No response is required. (The type of use will be specified on the license as possession and maintenance of radiologically contaminated equipment, with specific limitations.)

Item 10. Training of individual users

Persons who perform radiological surveys that are required by regulation and radioactive materials license must receive initial and annual radiation protection training. The scope of training needs to be commensurate with their duties. Appendix A contains a model training program. Confirm that you will follow the model or submit your proposed training program for review.

Item 11. Experience with radioactive materials for individual users

No response is required. Implementation of a training program as required in Item 10 of the application addresses Item 11 for the scope of license tasks.

Item 12. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

A model procedure for conducting a radiological survey is provided in Appendix C.

Item 13. Calibration and operational checks of instrumentation

Instrument calibrations must be performed before first use of the instrument and at intervals not to exceed 12 months by an entity that is licensed by the US Nuclear Regulatory Commission or an Agreement State to perform radiological survey instrument calibrations. The instrument must be checked for proper operation (minimally a battery condition check must be performed, and a response to a radiation source is recommended) on each day of use. Records of instrument calibrations must be maintained for a period of 5 years for review by the Department. Confirm that calibrations and daily battery checks will be performed as indicated above and that instrument calibration records will be maintained.

Item 14. Personnel monitoring and bioassays

Not applicable.

Item 15. Facilities and Equipment

Submit simple sketches of any storage area(s), pipe yards, etc., for contaminated equipment.

Item 16. Radiation Protection Program

The applicant does not need to establish a comprehensive radiation safety program. However, the applicant needs to implement a radiation protection program that is commensurate with the type of radioactive material authorized by the license. Appendix B contains a model radiation protection program. Please confirm that you will implement the model program or submit your proposed program for review.

Item 17. Waste Disposal

The applicant must plan for proper disposal of radiologically contaminated equipment when their use has been discontinued. Confirm that you will dispose of radiologically contaminated items in accordance with all applicable state and federal requirements.

Item 18. Certification

Provide the signature of the chief executive officer of the corporation or legal entity applying for the license or of an individual authorized by management to sign official documents and to certify that all information in this application is accurate to the best of the signator's knowledge and belief.

IV. AMENDMENTS TO LICENSES

Licensees are required to conduct their programs in accordance with statements, representations and procedures contained in the license application and supporting documents. The license must therefore be amended if the licensee plans to make any changes in the facilities, equipment, procedures, and authorized users or radiation safety officer, or the radioactive material to be used.

Applications for license amendments may be filed either on the application form or in letter form. The application should identify the license by number and should clearly describe the exact nature of the changes, additions, or deletions. References to previously submitted information and documents should be clear and specific and should identify the pertinent information by date, page and paragraph.

APPENDIX A Training Program for Individuals Performing Radiological Survey Measurements.

The applicant/licensee may use the services of a health physicist, licensed medical physicist or an individual who is authorized by a radioactive materials license to conduct radiological surveys. In these situations, the applicant/licensee needs to obtain documentation that the individual is qualified. Examples of documentation include a radioactive materials license that names the person as an authorized user, or copy of a resume for the health physicist or licensed medical physicist. Records of training must be maintained for a period of 5 years.

However, if the applicant/licensee plans to use his/her staff to conduct surveys, such individuals must receive training.

Individuals must demonstrate competence in the following subjects that prior to being approved to perform required surveys. Training must be conducted by an individual who is knowledgeable in health physics principles and procedures.

I. Fundamentals of Radiation Safety

- A. Characteristics of radiation
- B. Units of radiation dose and quantity of radioactivity
- C. Levels of radiation from sources of radiation
- D. Methods of minimizing radiation dose:
  1. working time
  2. working distance
  3. shielding

II. Radiation Detection Instruments

- A. Use of radiation survey instruments
  1. operational
  2. calibration

- B. Survey techniques

III. Requirements of the regulations and License Conditions

IV. Records of training will be maintained for a period of 5 years. Records will include the date of training, name of persons trained, name of the trainer and his/her employer, a copy of the training agenda or topics covered, and the results of any test or determination of proficiency. Records will be maintained for review by the Department.

APPENDIX B Radiation Protection Program

I. Responsibility

A. The owner/licensee will delegate authority to the Radiation Safety Officer to implement the program and the responsibility to oversee the day to day oversight of the program

B. Ensure that individuals receive initial and annual radiation protection training.

C. Ensure that radiological surveys are performed in an effective manner and at the time intervals required by the License.

D. Ensure that notifications required by regulations and License Conditions are made.

E. Ensure that an inventory of radiologically contaminated equipment is maintained.

F. Ensure that contaminated equipment in storage is labeled as containing radioactive material and is not released for unrestricted use.

G. Ensure that radioactive waste is disposed in accordance with all applicable state and federal requirements.

H. Ensure that only entities that have a specific license to perform decontamination perform service of equipment that exceeds 50 microrem at any accessible surface.

II. Maintain Records of:

A. Radiation Protection Training Program

B. Results of radiological surveys including instrumentation calibrations and operational checks.

C. Inventories of contaminated equipment

D. Waste disposal records

E. Service of contaminated equipment that exceeds 50 microrem at any accessible surface, including documentation of the service provider's radioactive materials license.

F. Radiological survey data

G. Maintain a complete radioactive materials license

APPENDIX C

Radiological Survey Guidance

I. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

II Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

NEW YORK STATE DEPARTMENT OF HEALTH
RADIOACTIVE MATERIALS LICENSE

Pursuant to the Public Health Law and Part 16 of the New York State Sanitary Code, and in reliance on statements and representations heretofore made by the licensee designated below, a license is hereby issued authorizing radioactive material(s) for the purpose(s), and at the place(s) designated below. The license is subject to all applicable rules, regulations, and orders now or hereafter in effect of all appropriate regulatory agencies and to any conditions specified below.

---

1. Name

_____

2. Address

_____

_____

Attention:
Radiation Safety Officer

3. License Number

4. a. Effective Date

_____

b. Expiration Date

_____

5. Reference Number
DH No. _____

---

6. Radioactive Materials (element & mass no.)	7. Chemical and/or Physical Form	8. Maximum quantity licensee may possess at one time
A. Radium 226	A. Any	A. As necessary
B. Naturally Occurring Radioactive Material (NORM)	B. Any	B. As necessary

9. Authorized use. The authorized locations of use are those specified in New York State Department of Environmental Conservation Permit to Drill Nos. _____.

A. The licensee is authorized for possession only of NORM listed in License Condition No. 6 as contamination in equipment incidental to oil and gas exploration and production.

B. The licensee may perform maintenance, not inculding decontamination or removal of scale containing radioactive material on equipment that does not exceed 50 microrem per hour at any accessible point.Only a licensee authorized by the US Nuclear Regulatory Commission or an

Agreement State to perform decontamination and decommissioning services shall service equipment that exceeds 50 microrem per hour at any accessible point.

10. A. Radioactive material listed in Item 6 shall be used by, or under the supervision of the Radiation Safety Officer.

_____ B.

C. The licensee shall notify the Department by letter within 30 days if the Radiation Safety Officer permanently discontinues performance of duties under the license.

11. Except as specifically provided otherwise by this license, the licensee shall possess and use licensed material described in Items 6, 7 and 8 of this license, in accordance with statements, representations, and procedures contained in the documents (including any enclosures) listed below:

A. Application for New York State Department of Health Radioactive Materials License dated _____, signed by _____.

B. Letter dated _____, signed by _____.

The New York State Department of Health's regulations shall govern the licensee's statements in applications or letters unless the statements are more restrictive than the regulations.

12. A. Transportation of licensed radioactive material shall be subject to all regulations of the U.S. Department of Transportation and other agencies of the United States having jurisdiction insofar as such regulations relate to the packaging of radioactive material, marking and labeling of the packages, loading and storage of packages, monitoring requirements, accident reporting, and shipping papers.

B. Transportation of low level radioactive waste shall be in accordance with the regulations of the New York State Department of Environmental Conservation as contained in 6 NYCRR Part 381.

13. The licensee shall have available appropriate survey instruments which shall be maintained operational and shall be calibrated before initial use and at subsequent intervals not exceeding twelve months by a person specifically authorized by the U.S. Nuclear Regulatory Commission or an Agreement State to perform such services. Records of all calibrations shall be kept a minimum of five years.

14, The licensee shall conduct gamma exposure rate measurements of accessable areas of gas production equipment within 6 months of the effective date of the license and at subsequent

intervals not to exceed 12 months. The licensee shall maintain measurement records for review by the Department. The licensee shall notify the Department within 7 calendar days following identification of any exposure rate measurement that meet or exceed 2 millirem per hour. Notification may be made by phone or in writing.

15. Equipment in storage that exceeds 50 microrem per hour at any accessible point shall be labeled by means of paint or durable label or tag.

16. The licensee shall maintain an inventory of equipment, including but not limited to tubular goods, piping, vessels, wellheads, separators, etc., that exceeds 50 microrem per hour at any accessible point. The records of the inventories shall be maintained for inspection by the Department, and shall include the location and description of the items, and the date that items were entered on the inventory record.

17. A. Before treatment or disposal of any gas production water in a manner that could result in discharge or release to the environment, the licensee shall obtain from the New York State Department of Environmental Conservation either:

    i) A valid permit, or

    ii) A letter stating that no permit is required.

    B. The licensee shall maintain the letter or valid permit required in paragraph A of this condition on file for the duration of the license and make such letter or permit available for inspection by the Department upon request.

18. The licensee shall submit complete decontamination procedures to the Department for approval ninety (90) days prior to the termination of operations involving radioactive materials.

19. Plans of facilities which the licensee intends to dedicate to operations involving the use of radioactive material shall be submitted to the Department for review and approval prior to any such use.

20. The licensee shall maintain records of information important to safe and effective decommissioning at the location listed in License Condition No. 2 and at other locations as the licensee chooses. The records shall be maintained until this license is terminated by the Department and shall include:

    A. Records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site;

    B. As-built drawings and modifications of structures and equipment in restricted areas where radioactive materials are used and/or stored, and locations of possible inaccessible contamination, such as buried pipes, which may be subject to contamination;

C. Records of the cost estimate performed for the decommissioning funding plan or the amount certified for decommissioning, and records of the funding method used for assuring funds if either a funding plan or certification is used.

21. The licensee may transfer contaminated equipment that exceeds 50 microrem at any accessible point to a Department licensee if the equipment is to be used in the oil and gas industry. The licensee shall maintain records of each transfer of equipment authorized by this License Condition.

FOR THE NEW YORK STATE DEPARTMENT OF HEALTH

Date: By _____
CJB/ :

Charles J. Burns, Chief
Radioactive Materials Section
Bureau of Environmental Radiation Protection

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context of this SGEIS and in accordance with Subpart 200.6 requirement defined in Section 6.5.1 to assure all potential adverse impacts are identified and rectified. The additional assessments performed for these short term impacts are addressed separately to distinguish certain information for PM10/PM2.5 gathered from industry since the initial modeling analysis in the SGEIS.

A) PM 10 and PM2.5 24-hour Impact Modeling and Potential Mitigation Measures.

As part of the Industry's Responses (dated September 16, 2009) to Information Requests, IOGA referenced a modeling assessment performed by consultants for Chesapeake Energy which incorporated a number of revisions to and recommendations on the Department's modeling analysis[90]. The analysis was based on one year of Binghamton meteorological data which indicated compliance with the PM10 NAAQS and much lower PM2.5 impacts than the Department's results, but still exceedances of the PM2.5 NAAQS. Mitigation measures were listed for resolving the latter exceedances. The analysis incorporated a set of assumptions which are summarized below with the Department's position on each of these:

The PM emissions provided by ALL consultants in the Industry Information Report were not speciated with respect to PM10 and PM2.5. Based on factors in EPA's AP-42 for large uncontrolled diesel engines, the PM10 and PM2.5 emissions represent 82% and 69%, respectively, of the total PM emissions. The Department has reviewed the information and agrees that the corresponding emissions should be adjusted accordingly;

The set of 15 completion equipment engines were represented in the Department's modeling as three sets of 5 units stationed next to each other. Industry noted that since these units contributed significantly to the modeled exceedances, each of the engines should be model as a separate point source. The Department had noted this conservative step and has remodeled the units are 15 separate sources. However, unlike Chesapeake's approach of separating the 15 units in two sets at the extreme ends of the pads, the Department has no reason to believe the engines would not be placed next to each other. Thus, the engines are re-modeled as depicted in revised Figure 6-5;

[90] June 21, 2010 letter from Brad Gill of IOGA-NY to Kathleen Sanford and associated modeling files.

It is claimed that the use of ULSF would result in an additional 10% reduction in PM emissions. The Department could not readily verify the level of reduction specifically for all diesel fuel sulfur contents, but it has been considered in our discussion of resultant impacts;

It was notes that the maximum emissions provided for the completion equipment engines are only representative of two hours in the operation cycle of these units. Thus, the hourly emission rate in the modeling was "prorated" to better characterize the likely 24-hour emission rate. The Department does not agree with this approach. As noted in our previous analysis, the ALL report noted a typical hydraulic fracturing operation can require up to 10 stages of total 5 hour periods. Thus, it is likely that a relevant portion of a day could experience the maximum hourly emission rate associated with worst case impacts, as we had previously assumed. Since there is no justified or simplified approach to account for this possibility, we believe it prudent to use the maximum hourly emission rate for the revised analysis; and

It was noted that for drilling engines, the use of the EPA "capping" stack option is not appropriate since the cap is "open" when the engines are in operation. This assumption has been revised in the reassessment by using the actual stack velocities and temperatures.

Finally, the Chesapeake modeling report noted that the background levels used were the maxima observed at representative monitors and are unreasonably high. The SGEIS recognizes the conservative nature of the background levels chosen as worst case observations, but notes that more representative values can be determined in instances where such refinement is necessary. For PM2.5, the reassessment has taken a less conservative approach in accord with the Department's and EPA's modeling guidance by reviewing the monitoring data and the expected associated average values in the Marcellus Shale area. In its March 23, 2010 guidance memo[91] on PM2.5, EPA provided a screening first Tier conservative approach to addressing NAAQS compliance which was to be followed by further guidance with more refined methods.

Lacking the follow-up guidance, most states, including New York, have allowed methods more in line with Section 8.2 of EPA's Modeling Guidelines. One such approach recognized by the March 23, 2010 memo is to allow for seasonal average observed concentrations. In reviewing

[91] Modeling Procedures for Demonstrating Compliance with PM2.5 NAAQS, Stephen Page, 3/23/10.

the data at monitors in the Marcellus Shale area, especially for the latest three years, we have identified a value of 15 µg/m^3 as appropriate for the purpose of determining representative 24-hour "regional" background level. The data also indicates that more recent observations than the 2005-7 levels in the SGEIS have in general shown a downward trend. It is also noted that the modeled impacts would dominate the total impacts which are to be compared to the NAAQS. For this reason, it is deemed appropriate to use the 8th highest concentration, as the form of the NAAQS, instead of the maximum 24-hour value recommended as a first screening Tier. A conservative step was to use the 8th highest maximum from each year of meteorological data modeled since these were limited to only two years per site.

In addition to these modifications to the original PM10 and PM2.5 modeling in the SGEIS, we have incorporated industry's assertion that there would not be simultaneous drilling and hydraulic fracturing operations at a single well pad. In order to better characterize the contribution of the completion equipment engines, the drilling rig engine and the air compressors, in addition to calculating the maximum overall impacts, the modeling results were also separated for each operation to determine the need for mitigation associated with each engine type. The modeling approach was otherwise identical to the previous analysis, except the version of AERMOD was updated to the version (09292) available at the time of the analysis.

The first step in the modeling exercise was to determine the maximum 24-hour PM10 and PM2.5 impact for each of the modeled years. These results are presented in Table 6.18. It is seen that the refined impacts which incorporate the above considerations are much lower than the values in Table 6.15. This reduction is due mainly to the speciated emission rates and the modeling of completion equipment engines as individual point sources. However, the impacts are still projected to be above the PM10 and PM2.5 NAAQS, except for the PM10 impacts associated with the drilling engines. As was noted previously, these maximum impacts occur next to the well pad and concentrations drop-off relatively sharply with downwind distance. The modeled impacts were reviewed and indicate that impacts above the NAAQS-minus-background levels value occurred at distances up to a maximum of 60m for completion equipment engines and PM10, while for PM2.5 the corresponding maximum distances were 120 and 150m for the drilling and completion equipment engines, respectively. The levels of the maximum impacts

also indicate that the different sets of engines could be dealt with using different mitigation measures.

As required by Part 617.11(5) (see next section for more details), the Department would pursue mitigation measures which eliminate potential adverse impacts to the maximum extent practicable. The August 26, 2009 industry report, the Industry Information Report and technical information from the public[92] identified a set of such potential measures which have been reviewed with this SEQRA requirement in mind. Certain of these suggestions would unlikely be practically implemented to any extent; for example, the use of electric engines could be very limited due to the remote nature of the drilling sites, while cleaner fuel engines are currently being investigated by engine manufacturers for future use. To the extent these alternative cleaner engines are available, the Department recommends their use. On the other hand, PM control equipment or the use of newer and cleaner engines are two measures recognized by both industry and the public as viable and the Department's review has concluded that these measures are practical. Appendix 18A provides the Department's review of the emission factors for various tiers of engines and potential after-treatment methods. Its conclusions are incorporated in the following discussions.

The discussions are limited to PM2.5 since these are the controlling impacts; that is, any measures to eliminate the PM2.5 exceedances would also assure compliance with the PM10 NAAQS. For the drilling rig and air compressor engines, the results in Table 6.18 were further analyzed to determine the impacts from each. The contribution to the overall maximum impact (Buffalo, 2007) for drilling operations was associated with the rig engines. Furthermore, industry has suggested and operational diagrams confirm that these engines are used close to the center of the well pad where the drilling actually occurs. The modeling results in Table 6.18 indicate that at a distance of 75m (from the center to the edge of the well pad) the drilling engine impacts are 30 $\mu g/m^3$, essentially due to the rig engine, which would still require mitigation when a background level of 15 $\mu g/m^3$ is used. Even if the 10% reduction in PM emissions due to the use of ULSF is achieved, as argued by industry, the resultant impact would still exceed the NAAQS. The rig engine impacts, however, are associated with ALL report's assumed Tier 1

[92] For example, comments by AKRF consultants on behalf of NRDC, Memorandum from Hillel Hammer, dated December 3, 2009, page 5.

engine emission factor. If the rig engines class was restricted to the use of Tier 2 and higher, then the PM2.5 impacts would be reduced by at least a factor of 2.7 (see Table Two of Appendix 18A, 0.4/0.15) which would result in compliance with the NAAQS regardless of where these engines are located on the well pad.

Industry data in the IOGA-NY information responses indicate that a majority (71%) of engines currently in use are Tier 2 and Tier 3 engines. In addition, a small fraction (3.5%) are uncertified (Tier 0), with "unknown" emissions. It is the Department's conclusion that these latter engines cannot be used for drilling in New York's Marcellus Shale since it has not been demonstrated that these would result in NAAQS compliance. Furthermore, since 25% of the current drilling engines are Tier 1, their use in New York should only take place with certain control measures. The discussions in Appendix 18A conclude that of the two exhaust after-treatment measures, Diesel Oxidation Catalyst (DOC) and Continuously Regenerating Diesel Particulate Filter (CRDPF) or particulate "traps", the latter is by far the more effective method in that it achieves almost three times the emission reduction (i.e., 85% vs 30%). The level of control achieved by the traps is necessary to alleviate all PM2.5 NAAQS exceedances from any Tier 1 drilling engines. Thus, the CRDPF traps should be the after-treatment for Tier 1 drilling engines if these are to be used in New York. This conclusion also applies to the air compressors for which the maximum PM2.5 impact is calculated to be 65ug/m^3 for Tier 1 emissions. On the other hand, Tier 2 and above drilling rig engines and air compressors demonstrate NAAQS compliance without these controls.

The Department also considered the "mitigation" of the NAAQS exceedances by stack height and distance restriction measures identified previously in the SGEIS. Although the IOGA-NY response also lists the stack height increase on the drilling engines as a potential measure, there is no indication from industry if such measures are practical given the stack configuration of these engines and the height to which these would be extended. In addition, this measure is not in strict accord with the need to mitigate the adverse impacts to the maximum extent practicable. The combination of operating these engines closer to the drilling rig, but more importantly the use of CRDPF traps on Tier 1 engines are deemed the necessary mitigation measures.

Turning next to the completion equipment engines, it seems even less practical to apply the distance and stack height increase restrictions to this class of engines. In fact, industry has previously indicated that stack height increase on these mobile units cannot be practically accomplished. A modeling run indicates that in order to meet the PM2.5 standard under the revised set of assumptions, the stack height would need to be at least doubled. Furthermore, the distance at which impacts are projected to be below the NAAQS-minus-background level was noted previously to be 150m. This is based on the Tier 2 emission factor modeled for these engines as provided by the ALL report. Consequently, the required practical approach to these engines would also require the use of the CRDPF traps as after-treatment on Tier 2 engines. For the maximum 24-hour PM2.5 case of Table 6.18 (Buffalo, 2006), the 202 $\mu g/m^3$ impact reduces to 44 $\mu g/m^3$ at a distance of 75m from the engines. Again, a 10% reduction in PM emissions due the use of ULSF does not alleviate these exceedances. Furthermore, unlike the smaller drilling engines, the ability of placing the 15 completion equipment engines (typically 14 used in Pennsylvania) near the center of the well pad is questionable. Based on industry's depiction, it is possible to separate these into two sets at either side of the hydraulic fracturing operations to further reduce impacts. In sum, however, the number of Tier 2 completion equipment engines which would require the installation of the particulate traps ranges from at least two thirds to all of the 15 engines per hydraulic fracturing job. For practical purposes, it is recommended that all Tier 2 engines be equipped with the CRDPF traps. Otherwise, each well operation might need to undergo more site specific analysis to demonstrate that a certain configuration or PM trap installation alternative would assure compliance with the 24-hour PM2.5 and PM10 NAAQS. Further details on the practicality of requiring these traps and other after-treatment control measures are discussed in the section following the SO_2 and NO_2 modeling results.

With respect to the Tier 0 and Tier 1 completion equipment engines, these emissions have not been analyzed or modeled, but for the same reasons as for the drilling engines, Tier 0 completion equipment engines should not be used in New York. In addition, based on the scaling of the maximum impact in Table 6.18 by the ratio of Tier 1 to Tier 2 emission factors (2.7), it is determined that Tier 1 engines have the potential to cause a modeled exceedance even if equipped with a particulate trap (maximum impact of 82 $\mu g/m^3$ with 85% control). Industry can suggest impact mitigation in addition to the use of PM traps in order to show compliance with

the NAAQS, but lacking such a demonstration, it is the Department's interim conclusion that Tier 1 completion equipment engines should not be used in New York. On the other hand, and as also suggested by industry and the public, newer Tier 4 engines, which would likely be equipped with traps in order to achieve the required emission factors for those engines, can be used as an alternative to the Tier 2 engines with a PM trap.

B) SO_2 and NO_2 1-hour Impacts and Potential Mitigation Measures.

The 1-hour SO_2 and NO_2 NAAQS were promulgated since September 2009. Permitting and SEQRA actions after the effective date of an NAAQS are addressed by the Department to assure compliance with the NAAQS in accord with standard Department and EPA policy and requirements. EPA Region 2 recommended that the Department consider the new NAAQS in the SGEIS. In accord with the SEQRA process and the Department's Subpart 200.6 requirement, the Department has modeled the 1-hour SO_2 and NO_2 impacts to assure that all NAAQS are met.

With respect to the 1-hour SO_2 standard of 196 $\mu g/m^3$, no detailed modeling was determined necessary. Instead, the results of the previous SO_2 3-hour modeling in Table 6.15 indicated that the use of the ULSF would likely result in 1-hour impacts being below the NAAQS. Thus, the 1-hour maximum CO impact in Table 6.15 was used to scale the corresponding 1-hour maximum SO_2 impacts using the ratio of the fracturing engine SO_2 and CO emissions since these engines were responsible for the overall maxima. The resultant maximum impact is calculated to be 24 $\mu g/m^3$. Using a representative, yet conservative, maximum 1-hour SO_2 level of 126 $\mu g/m^3$ from the Elmira monitor for 2009 gives a total impact of 150 $\mu g/m^3$ which is below the corresponding NAAQS of 196 $\mu g/m^3$. Thus, no further modeling was necessary to demonstrate compliance with the 1-hour SO_2 standard.

Simple scaling to demonstrate compliance was not possible for the NO_2 1-hour impacts due to the very large concentrations projected using the same method. Instead, it was necessary to account for a number of refinements in the modeling based on EPA and Department guidelines. There are at least two main aspects to the NO_2 modeling which need to be addressed in such refinements. These issues have been raised by EPA, industry and regulatory agencies as needing

further guidance. Similar to the PM2.5 guidance, EPA released a memorandum[93] on June 29, 2010 which provides guidance on how to perform a first Tier assessment for the NO_2 NAAQS. More recently, EPA has provided further guidance [94]on particulars in the modeling approach for NO_2 1-hour NAAQS compliance determinations.

The two main issues which have been raised deal with: 1) the form of the standard, as the 3 year average of the 98% of the daily maximum 1-hour value, which the AERMOD model used for the original modeling and the revised PM2.5 modeling are not set to calculate, and 2) the ratio of NO_2 to NO_x emissions assumed for stacks from various source types. Of these, the latter is more critical since NO_2 is a small fraction of the NO_x emissions in essentially all source types and assuming all of the NO_x emissions are NO_2 is unrealistic. These issues, however, are not insurmountable. For example, there are model post processors offered by consultants which can readily resolve the first issue. At the time of our re-analysis, EPA provided the Department with a "beta" version of AERMOD which performs the correct averages for NO_2. Some limited preliminary supplemental modeling used that model version, but the Department has recalculated these impacts using the final version of AERMOD (11059) released on 4/8/11 to assure proper calculation of the 8th highest 1-hour maximum per day of meteorological data. The results discussed below reflect the use of this version of AERMOD. It should be noted that the revised version of AERMOD does not contain any changes significant enough to affect the PM2.5 analysis.

With respect to the second issue, a number of entities, including EPA and the Department, have gathered information on the NO_2 to NO_x ratios from various source types which can be incorporated in the modeling. For the specific drilling and completion equipment engines, Department staff has undertaken a review of available information and has made recommendations on this issue. The details of the recommendations are provided in Appendix 18A which are used in the analysis to be discussed shortly. In addition to this ratio, EPA and Department guidance allows the use of two methods to refine NO_2 modeled impacts; the Ozone

[93] *Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program.* Memo from Stephen Page, EPA OAQPS, dated June 29, 2010.

[94] *Additional Clarifications Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS.* Memo from Tyler Fox, EPA OAQPS, dated March 1, 2011.

Limiting Method (OLM) and the Plume Volume Molar Ratio Method (PVMRM). There is no preference indicated in EPA guidance as to which method might provide more refinement. However, based on limited model evaluation results presented in the March 1, 2011 EPA guidance memorandum, the current analysis has relied upon the OLM method with the appropriate "source group" option (OLMGROUP ALL) noted in the EPA memo.

In addition to the NO_2/NO_x ratio, hourly O_3 data is necessary for the use of the method. These were taken from available Department observations at monitor sites representative of the meteorological data bases discussed in the original analysis section. Furthermore, for the determination of background 1-hour NO_2 values, we have refined EPA's first Tier screening approach of using the highest observed levels by calculating the average of the readily available 3rd-highest observations from the Department's Amherst and Pinnacle State Park monitors for the year 2009. This calculated value is 50 $\mu g/m^3$ and is still conservative relative to the form of the NO_2 standard, as well as relative to further refinements allowed by EPA and Department guidance.

Appendix 18A recommends that, for engines for which emissions were calculated by the Industry Information Report and used in the Department's modeling, the NO_2 fraction of NO_x is 11% without after-treatment. Thus, an initial set of model runs were performed for the completion equipment engines using the two years of Albany data and this ratio of 0.11 in AERMOD. The results indicate that the maximum impacts from the hydraulic fracturing operations with the 0.11 factor (without the OLM approach) were approximately 3500 $\mu g/m^3$ which, although lower than those from the simple scaling of the CO impacts, are still an order of magnitude above the 1-hour standard of 188 $\mu g/m^3$ for the hydraulic fracturing operations. The impact was noted to be above the NAAQS out to a distance of 300 m from the pad. Thus, further refinements were necessary by the AERMOD-OLM approach.

First to consider, however, is that a confounding issue which this initial modeling did not include was the discovery that the NO_2 to NO_x ratio is increased by the particulate trap from 0.11 to 0.35 due to the generation of NO_2 in order to oxidize and remove the particulates (see Appendix 18A). This would lead to even higher NO_2 impacts. These results clearly indicate that some form of after-treatment exhaust control method is necessary for the completion equipment

engines. The after-treatment methods to reduce NO_x emissions are discussed in Appendix 18A which indicates that at present the recommended exhaust treatment method in practical use for on-road engines or engines in general is the SCR system. As noted in Appendix 18A, this preferred after-treatment method for NO_x control would reduce the NO_2 to NO_x ratio (with the CRDPF traps in place) down to essentially the same value as without the traps (i.e. 0.10). Of course, the SCR system would also substantially reduces the NO_x emissions by 90%. Therefore, the last step in the modeling of the completion equipment engines was to use the 90% reduction in emissions and the NO_2/ NO_x ratio of 0.10 with the OLM option. The analysis relied on the Tier 2 emissions provided by the Industry Information Report as the base emissions which were then reduced by 90% by the SCR controls. This level of modeling was deemed the most refinement allowed currently by Department and EPA guidance.

For the drilling engines, an initial modeling was performed first without the SCR controls and the 0.11 NO_2/NO_x ratio and the drilling rig Tier 1 emissions provided in the Industry Information Report as representative of the maximum emission case. For the compressors, Tier 2 was provided as the worst case emissions for the modeling of short term impacts. Based on two years of Albany meteorological data, it was found that the rig engines would exceed the NO_2 1-hour standard by about a factor of two and impacts would be above the NAAQS-minus-background level out to a distance of 150 m. From the modeling for PM2.5, it was found that the Tier 1 rig engines would need to be equipped with a PM trap in order to project compliance with the 24-hour PM2.5 standard. Since the traps were found to increase the NO2/ NO_x ratio by three fold, it is clear that the Tier 1 rig engine impacts would be substantially above the 1-hour NO_2 NAAQS without reductions in the NO_2 emissions. Thus, it is concluded that any Tier 1 rig engines (and compressors by analogy) would need to be equipped with both a PM trap and SCR for use in New York drilling activities.

Thus, the final set of modeling analysis used the SCR controlled Tier 2 completion equipment engine emissions with a NO_2/NO_x ratio of 0.10 and Tier 2 drilling rig engines and air compressor engines (both of which do not require PM traps) with the NO_2/ NO_x ratio set to 0.11 as noted previously. As for the completion equipment engines, the NO_2 modeling for the rig engines and compressors was based on more realistic representation of the units as individual units of five separate, but contiguous point sources as a further refinement to represent their configuration.

The emissions for each were scaled from the totals in Table 8 of the 8/26/09 Industry Report and these were placed in a north-south orientation at the same location as in Figure 6-2.

The set of NO_2 modeling with all of the meteorological data sites considered all potential sources as in previous analysis, but also provided the maximum impact for each of the three types of engines in order to determine specific potential necessary mitigation measures. However, initial modeling of the combined "drilling" scenario using two years of Albany data indicated an inconsistence in the total projected impacts in comparison to the results from the rig engines and compressors separately. This raised a potential issue with the "combined" impacts from these two operations which was related to the specifics of the OLM Ozone "distribution" approach. The resolution of this issue for the purposes of determining impacts from the rig engines and compressors and the need for potential mitigation measure was to recommend to place these two types of engines near the rig in the center of the well pad (as in the case of the PM results) and, furthermore, to separate these on either side of the drill rig to minimize combined impacts. A single year model run indicated this minimized combined impacts. From information and diagrams available, it is clear that these engines are in fact placed near the center of the pad when in actual operation.

The results of the 1-hour NO_2 impacts are presented in Table 6.18. As noted in the table, all engine are based on Tier 2 emissions, with the completion equipment engines assume to use SCR controls. The results for each of the meteorological data years, the overall maxima, the impacts at a 75-m distance (from center of pad to boundary), and the distance at which the impacts fall off to the NAAQS-background value of 138 $\mu g/m^3$ are presented for the completion equipment engines, the rig engines and the compressors. It is seen that the overall maxima are above the NAAQS. However, these need to be qualified relative to the other information tabulated in terms of potential mitigation measures necessary. It should be noted that a number of conservative assumptions are related to these impacts. First, it is noted that if the sources are placed in the center of the pad, as recommended, the impacts are much lower and essentially below the 1-hour NAAQS. Furthermore, these impacts should be adjusted downward by 10% since the tiered emission "limits" for Tier 2 and above are at most 90% NO_x as described in Appendix 18A. In addition, the background level used is conservative in that it represents the average of the third highest observations in the shale area and can be adjusted downwards.

Lastly, the distance to achieve the NAAQS minus background level is seen in the Table to be very close to the edge of the well pad. Using concentration maps for the three engine types indicate a sharp drop off of impacts such that the NAAQS minus background level is reached essentially at the well pad edge with only the 10% downward adjustment to impacts. In total, these considerations result in the NO_2 impacts being below the 1-hour NAAQS with the proper placement of the engines near the center of the well pad and the use of SCR control on the fracturing engines, coupled with Tier 2 or higher engines.

As discussed in Appendix 18A, SCR control is the only currently available NO_x reduction system for these size engines which has demonstrated the ability to practically achieve the level of reduction necessary (i.e., minimum 90%) to meet the NAAQS. Since the results of the PM2.5 modeling concluded that Tier 0 (uncertified) and Tier 1 completion equipment engines are not recommended for use in New York if CRDPF (particulate traps) are retrofitted to these, the application of SCR to Tier 2 and newer engines were considered. It is the Department's understanding from the manufacturers of these engines that the Tier 4 engines would have to be equipped with PM traps and SCR in order to meet the more stringent emission limits. It should be recalled that without the SCR control, the particulate traps increase the NO_2 to NO_x ratio by three fold and the corresponding impacts by a similar magnitude. Thus, the SCR system should be installed on all engines in which PM traps are being required for PM2.5 NAAQS compliance purposes. Any alternate system proposed by industry which has a demonstrated ability to achieve the same level of PM and NO_x reduction and, concurrently, resolve the NO_2 increase by the particulate traps in order to meet the NAAQS would be considered by the Department. At the present time, the Department is not aware of such an alternative system which has a proven record. For the purposes of the SGEIS, the Department has determined that the SCR system is necessary and adequate for this purpose. The next section discusses the practicality of using both the particulate traps and SCRs on completion equipment engines.

A summary of the Department's determination on the EPA Tier engines and the necessary mitigations to achieve the 24-hour PM2.5 and 1-hour NO_2 NAAQS is presented in tabular form in Table 6.19. The first column provides the various EPA tiers for the drilling and completion equipment engines and their time lines as presented in Appendix 18A. The next column presents sample percent of each Tier engines currently in use as provided by industry in the Information

Report. Note that based on the previous discussions, the uncertified (Tier 0) engines would not be allowed to be used in NY for Marcellus Shale activities. The third column provides the ratio of the Tier 1 emission rates for PM and NO_x to the other tiers, based on the information in Appendix 18A. The last column summarizes the determinations made by the Department on the control requirements necessary to meet the 24-hour PM2.5 (and PM10) and the 1-hour NO_2 ambient standards. As seen from the table, Tier 1 drilling engines and air compressors would require a PM trap and SCR controls, with the same controls being required on most of the completion equipment engine tiers.

Another purpose of this table is to provide an important demonstration that the Department's recommendations on control measure for these engines would result in substantial emission reduction over the current levels allowed in any other operations in other states. That is, in terms of air quality impacts, the emission reduction factor column of Table 6.19 indicates at least a factor of 3 and 2 reductions in PM2.5 and NO_2 emissions, respectively, from the Tier 1 engines. Thus, although Tier 2 and 3 drilling engines make up a majority of the engines in current use (71%), their relative emissions are much lower than the Tier 1 engines, which are recommended not to be used in NY (or have PM traps and SCR controls with about 90% reductions in emissions). Therefore, in terms of emissions reductions, the Department's requirements on the drilling engines would reduce emissions by at least half. Furthermore, since the completion equipment engines are about four times larger than the drilling engines, the imposition of PM traps and SCR on most completion equipment engines means a substantial reduction in overall PM and NO_x emissions from the set of engines to be used in New York. Any alternative emission reduction schemes which industry might further pursue would be judged against these reductions. It is clear however, that the Department would assure that any such control or mitigation measure would explicitly demonstrate compliance with the ambient air quality standards.

6.5.2.6 The Practicality of Mitigation Measures on the Completion Equipment and Drilling Engines.

The supplemental modeling assessment has concluded that in order to meet the ambient standards for the 24-hr PM2.5 and the 1-hour NO_2 NAAQS, it is necessary that the completion equipment engines tiers allowed to be used in New York to be equipped with particulate filter

traps (CRDPF) and SCR control for NO_x. These are Tier 2 and newer completion equipment engines. Similarly, the Tier 1 rig engines and air compressors would be required to be equipped with both control devices if these are used in New York. The determination on the specific after-treatment controls was based on the review of available control methods used in practice (see Appendix 18A). Currently available alternative control measures considered were deemed inadequate for the purpose of achieving the level of PM2.5 and NO_x emission reductions necessary to demonstrate NAAQS compliance and/or having a proven record of use in practice.

Although industry can attempt to perform an independent assessment of alternatives to the recommended exhaust after-treatment controls, it is highly likely that a certain level of control equipment recommended would be necessary on these engines. If industry indentifies viable alternative control measure which can be demonstrated to achieve the same level of emission reduction for NAAQS standard compliance, these alternative schemes would need to be submitted for Department review and concurrence prior to their use in New York. Furthermore, in recommending the use of particulate traps and the SCR technology, Department staff has considered the requirements of subsection 617.11.5 and the practicality of the chosen measures.

Taking the diesel particulate traps and the SCR controls separately, it is fair to say that since the former have a longer established history of actual use than the latter on types of engines of size in the rig engine class, the demonstration of practicality for the traps might be less onerous. For example, industry itself has identified these diesel particulate traps on Tier 2 and 3 engines in their list of mitigation measure.[95] In addition, public information (see footnote 17) also has identified the ongoing use of diesel traps as a required mitigation measure by Metropolitan Transportation Authority (MTA) for non-road engines in major construction projects in NYC. These latter engines, however, are in the size range of the smaller rig engines and not in the completion equipment engine range. Information on the ongoing practical use of particulate traps in these and similar activities have been further confirmed by Department staff through publically available information. Thus, while it can be concluded that the requirement to use particulate traps on certain EPA tiered engines is in accord with Subsection 200.6 and 617.11 of the Department's requirements, it is nonetheless necessary for industry to further assess the

[95] Page 43 of the ALL/IOGA September 16, 2010 Information Request Report.

practicality of their use for the completion equipment engine size range. Based on limited conversations with two of the engine manufacturers indicated that the main issue still to be resolved is the details of the engineering necessary to use PM traps as after-treatment equipment. The concern relates to the need for "stand alone" equipment for each of the completion equipment engines which differs from the built-in or add on components being currently used for the smaller on-road or off-road engines. To the Department's knowledge, currently neither PM and NO_2 control measures are being used by the gas drilling industry for other shale activities to any extent. However, it is the Department's assumption that the PM traps can be feasibly used on the Tier 1 drilling engines and compressors and the Tier 1 and 2 completion equipment engines.

For the use of SCR as the Department's preferred control measure to reduce NOx emissions from all of the completion equipment engines allowed to be used in New York, there is less information on similar size engines. As Appendix 18A notes, however, these units are widely used in a package with particulate traps on heavy duty vehicles and there is no operational reason that the same cannot be achieved with the larger completion equipment engines. One way to judge the practicality of using SCR control on these engines is to consider the costs involved. The Department has undertaken a simple approach to this issue by using the analogy to reducing exhaust stream NOx emission and its "cost effectiveness" as a means for major stationary sources to get a "waiver" from the emission control limits set forth in Subpart 227-2 (Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x)). That is, if a source can demonstrate that the costs associated with the imposed emission limits are unreasonable, the Department and EPA would consider granting a waiver from meeting these limits.

Details of an analysis of the "cost effectiveness" of the SCR controls for completion equipment engines and the comparable value currently used by the Department for stationary sources is provided in Appendix 18B. It is important to note that the "cost effectiveness" is based on acceptable "engine size scaling-up" method for the completion equipment engines with certain assumptions which might not be representative of the actual cost of installation of SCR after treatment. The calculations in Appendix 18B indicate that the cost of requiring SCR on the completion equipment engines is within the value used by the Department for stationary sources

and is deemed reasonable. The cost effectiveness for the smaller drilling engines should be lower. It is recognized that the applicability of 227.2 RACT requirements are meant for major individual stationary sources, but it is also to be noted that the potential annual NO_x emissions from the sum total of engine use throughout the Marcellus Shale are rather large, as discussed in the next section. Based on the conversations with the engine manufacturers, the main concern with the installation of SCR as an after-treatment control relates again to the need for a "stand-alone" system on the completion equipment engines, with the added complexity that these systems would require "continuous" maintenance to achieve the level of reduction assumed in the Department's analysis. In addition, these discussions indicate that the cost associated with the installation of the PM traps and SCR are likely above those assumed by the Department. A calculation using the approach in Appendix 18C for PM after-treatment indicates that the "cost effectiveness" value is well above the value used for NO_x RACT waiver determinations. Thus, it is recommended that industry undertake a detailed assessment of the PM traps and SCR controls in addressing the Department's recommendations of these controls as the required mitigation measures on certain Tier drilling and completion equipment engines in order to demonstrate compliance with the 24-hour PM2.5 and 1-hour NO_2 NAAQS.

Based on the above discussions, the Department believes that the use of particulate traps and SCR controls are reasonable and practical in achieving the mitigation of potential adverse 24-hour PM2.5 and 1-hour NO_2 impacts, respectively. As noted previously, industry can present equivalent control measures and background information for further Department considerations. Regardless of the specific measure, however, it should be made clear that the Department is required to assure compliance with ambient standards with respect to any other control measures which could put forth by industry or the public. One of the mitigation "measures" noted by industry in their Information Report, at least for NO_x emissions, is to allow for the "natural" fleet turnover of the EPA tiers as these requirements would "kick-in" over time. This suggestion is not an acceptable scheme, given that none of the engines currently in use or contemplated are the interim Tier 4 engines, which become effective in 2011, based on the Department's knowledge and industry data. If industry is to advance such a mitigation scheme, it would submit an acceptable timeline which clearly sets out an aggressive schedule to implement the Tier 4 engines. Based on engine manufacturer's information, there is ongoing efforts to achieve the

Tier 4 emission standards before the 2014/15 timelines noted in Table 6.19. Such an implementation schedule can be tied to the specific tiered engine after-treatment controls required by the Department.

6.5.2.7 Conclusions from the Modeling Analysis

An air quality impact analysis was undertaken of various sources of air pollution emissions from a multi-horizontal well pad and an example compressor station located next to a typical site in the area underlain by the Marcellus Shale. The analysis relied on recommended EPA and Department modeling procedures and input data assumptions. Due to the extensive area underlain by the Marcellus Shale and other low-permeability gas reservoirs in New York, certain assumptions and simplifications had to be made in order to properly simulate the impacts from a "typical" site such that the results would be generally applicable. At the same time, an adequate meteorological data base from a number of locations was used to assure proper representation of the potential well sites in the area underlain by the Marcellus Shale in New York.

Information pertaining to onsite and offsite combustion and gas venting sources and the corresponding emissions and stack parameters were initially provided by industry and independently verified by Department staff. The emission information was provided for the gas drilling, completion and production phases of expected operations. On the other hand, emissions of potential additive chemicals from the flowback water impoundments, which were proposed by industry as one means for reuse of water, were not provided by industry or an ICF report to NYSERDA. Thus, worst-case emission rates were developed by the Department using an EPA emission model for a set of representative chemicals which were determined to likely control the potential worst case impacts, using information provided by the hydraulic fracturing completion operators. The information included the compounds used for various purposes in the hydraulic fracturing process and the relative content of the various chemicals by percent weight. The resultant calculated emission rates were shared with industry for their input and comment prior to the modeling.

The modeling analysis of all sources was carried out for the short-term and annual averages of the ambient air quality standards for criteria pollutants and for Department defined threshold levels for non-criteria pollutants. The initial modeling used limitations on simultaneous

operations of the various equipment at both onsite and offsite operations for a multi-well pad in the analysis for the short-term averages, while the annual impacts accounted for the potential use of equipment at the well pad over one year period for the purpose of drilling up to a maximum of ten wells. For the modeling of chemicals in the flowback water, two impoundments of expected worst case size were used based on information from industry: a smaller on-site and a larger off-site (or centralized) impoundment.

Initial modeling results indicated compliance with the majority of ambient thresholds, but also identified certain pollutants which were projected to be exceeded due to specific sources emission rates and stack parameters provided in the Industry Information Report. It was noted that many of these exceedances related to the very short stacks and associated structure downwash effects for the engines and compressors used in the various phases of operations. Thus, limited additional modeling was undertaken to determine whether simple adjustments to the stack height might alleviate the exceedances as one mitigation measure which could be implemented. An estimate of the distances at which the impacts would reduce to below all applicable SGCs and SGCs were provided as part of the original analysis.

Based on recent information provided by industry on the operational restrictions at the well pad, the elimination of the flowback impoundments, and a limited modeling of 24-hour PM2.5 impacts, the initial Department assessment was revisited. In addition, due to the promulgation of new 1-hour SO_2 and NO_2 NAAQS after September 2009, further modeling was performed. The significant consequences of the revised restrictions on simultaneous operations of the drilling and completion equipment engines, the number of wells to be drilled per year, and the elimination of the impoundments are incorporated in the initial modeling assessment. Further modeling details for the short term PM2.5, NO_2 and SO_2 impacts are presented in a supplemental modeling section. These results indicate the need for the imposition of certain control measures to achieve the NO_2 and PM2.5 NAAQS. These measures, along with all other restrictions reflecting industry's proposals and based on the modeling results, are detailed in Section 6.5.5 as well permit operation conditions.

Table 6.12 - Sources and Pollutants Modeled for Short-Term Simultaneous Operations

Pollutant → / Source	SO_2	NO_2	PM10 & PM2.5	CO	Non-criteria combustion emissions	H_2S and other gas constituents
Engines for drilling	✔	✔	✔	✔		
Compressors for drilling	✔	✔	✔	✔	✔	
Engines for hydraulic fracturing	✔	✔	✔	✔	✔	
Line heaters	✔	✔	✔	✔	✔	
Off-site compressors	✔	✔	✔	✔	✔	
Flowback gas flaring	✔	✔	✔	✔	✔	
Gas venting						✔
Mud-gas separator						✔
Glycol dehydrator					✔	✔

Table 6.13 - National Weather Service Data Sites Used in the Modeling

NWS Data Site	Meteorology Data Years	Latitude/Longitude Coordinates
Albany	2007-08	42.747/73.799
Syracuse	2007-08	43.111/76.104
Binghamton	2007-08	42.207/75.980
Jamestown	2001-02	42.153/79.254
Buffalo	2006-07	42.940/78.736
Montgomery	2005-06	41.509/74.266

Table 6.14 - National Ambient Air Quality Standards (NAAQS), PSD Increments & Significant Impact Levels (SILs) for Criteria Pollutants (μg/m^3)

Pollutant	1-hour	3-hour	8-hour	24-hour	Annual
SO_2 NAAQS	196	1300		365	80
PSD Increment		512		91	20
SILs		25		5	1
PM10 NAAQS				150	50
PSD Increment				30	17
SILs				5	1
PM2.5 NAAQS				35	15
PSD Increment				9	4
SILs[96]				1.2	0.3
NO2 NAAQS	188				100
PSD Increment					25
SILs					1.0
CO NAAQS	40,000		10,000		
SILs	2000		500		

[96] The PM2.5 standards reflect the 3 year averages with the 24 hour standard being calculated as the 98th percentile value.

Table 6.15 - Maximum Background Concentration from Department Monitor Sites

Pollutant	Monitor Sites	Maximum Observed Values for 2005-2007 ($\mu g/m^3$)
SO_2	Elmira* and Belleayre	3 hour - 125 24-hour - 37 Annual - 8
NO_2	Amherst	Annual - 26
PM10**	Newburgh* and Belleayre	24-hour - 49 Annual - 13
PM2.5	Newburgh* and Pinnacle State Park	24-hour - 30 Annual - 11 (3 year averages per NAAQS)
CO	Loudonville	1-hour - 1714 8 hour - 1112

* Denotes the site with the higher numbers.
** For PM10, data from years 2002-4 was used.

Table 6.16 - Maximum Impacts of Criteria Pollutants for Each Meteorological Data Set

Meteorological Data Year & Location		SO_2 3-hour	SO_2 24-hour	SO_2 Annual	PM10 24-hour	PM10 Annual	PM2.5* 24-hour	PM2.5* Annual	CO 1-hour	CO 8-hour	NO_2 Annual
Albany	2007	15.4	13.3	3.1	459	2.7	355	2.7	9270	8209	57.9
	2008	15.3	13.2	2.9		2.4		2.4	9262	8298	51.0
Syracuse	2007	15.9	12.6	2.8		2.7		2.7	8631	7849	57.1
	2008	15.8	14.3	2.7		2.7		2.7	8626	7774	55.4
Binghamton	2007	18.5	13.4	2.3		2.1		2.1	10122	8751	45.5
	2008	18.6	15.4	1.9		1.8		1.8	9970	8758	37.6
Jamestown	2001	16.7	14.0	2.4		2.1		2.1	8874	8193	46.4
	2002	16.8	14.4	2.7		2.3		2.3	8765	8199	50.9
Buffalo	2006	16.6	15.7	3.2		2.9		2.9	9023	8067	63.2
	2007	16.9	14.4	3.1		2.8		2.8	8910	8270	60.8
Montgomery	2005	17.4	11.6	1.9		1.8		1.8	9362	8226	38.4
	2006	14.4	14.0	2.2		2.0		2.0	9529	8301	41.9
Maximum		18.6	15.7	3.2		2.9		2.9	10122	8758	63.2
Impact at 500m		0.3	0.3	0.05	7.1	.11	5.0	.11	480	253	2.5

Note: 24-hour PM2.5 values are the 8th highest impact per the standard.

Table 6.17 - Maximum Project Impacts of Criteria Pollutants and Comparison to SILs, PSD Increments and Ambient Standards

Pollutant and Averaging Time	Maximum Impact ($\mu g/m^3$)	SIL*	Worst Case Background Level ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Increment Impact** ($\mu g/m^3$)	PSD* Increment ($\mu g/m^3$)
SO_2 - 3 hour	18.6	25	125	143.6	1300	18.6	512
SO_2 - 24-hour	15.7	5	37	52.7	365	15.7	91
SO_2 - Annual	3.2	1	8	11.2	80	3.2	20
PM10 - 24-hour	459***	5	49	508***	150	6.5**	30
PM10 - Annual	2.9	1	13	15.9	50	2.9	17
PM2.5 - 24-hour	355***	1.2	30***	385***	35	6.5**	9
PM2.5 - Annual	2.9	0.3	11	13.9	15	2.9	4
NO_2 - Annual	63.2	1.0	26	89.2	100	5.6**	25
CO - 1-hour	10,122	2000	1714	11,836	40,000	NA	None
CO - 8 hour	8758	500	1112	9870	10,000	NA	None

* SILs and increments for PM2.5 included in revised Table from EPA's final PSD rule for PM2.5

** Impacts from the off-site compressor plus the line heater only for PSD increment comparisons were recalculated for annual NO_2 and PM10 and PM2.5 24-hour cases. NA means not applicable

*** See Supplemental Modeling Section for revised analysis

Table 6.18 - Maximum Impacts of Non-Criteria Pollutants and Comparisons to SGC/AGC and New York State AAQS

Pollutant	Total Venting Emission Rate (g/s)	Impacts from all Venting Sources ($\mu g/m^3$)		All Combustion Sources and Dehydrator Impacts ($\mu g/m^3$)			
		Max 1-hr	SGC	Max 1-hr	SGC	Annual	AGC
Benzene***	0.218	140	1,300	13.2	1,300	0.90 0.10	0.13
Xylene	0.60	365	4,300	NA**	4,300	NA	100
Toluene	0.78	500	37,000	NA	37,000	NA	5,000
Hexane	9.18	5,888	43,000				
H_2S***	0.096	61.5 12.1	14*				
Formaldehyde**				4.4	30	0.20 0.04	0.06
Acetaldehyde				NA	4,500	0.06	0.45
Naphthalene				NA	7,900	NA	3.0
Propylene				NA	21,000	NA	3,000

* Denotes the New York State 1-hour standard for H_2S

** Denotes not analyzed by modeling, but the SGCs and AGCs would be met (see text)

*** AGC exceedance for benzene is eliminated by raising the dehydrator stack to 9.1m

The standard exceedance for H_2S is eliminated by using a minimum stack height of 9.1m for gas venting

The AGC exceedance for formaldehyde is eliminated by using a compressor stack height of 7.6m

Table 6.19 - Modeling Results for Short Term PM10, PM2.5 and NO_2 (New July 2011)

Met Data Location	Met Data Year	PM10, 24-hr (µg/m^3)		PM2.5, 24-hr (µg/m^3)		NO_2, 1-hour impact (µg/m^3) (see NOTE)		
		Hydraulic Fracturing	Drilling	Hydraulic Fracturing	Drilling	Hydraulic Fracturing	Rig Engine	Compressor
Albany	2007	313	76	152	36	198	256	216
	2008	268	84	129	40	198	259	230
Syracuse	2007	224	95	144	34	156	196	198
	2008	327	81	120	27	161	180	208
Binghamton	2007	281	87	154	34	194	239	208
	2008	327	89	121	35	213	231	220
Jamestown	2001	339	74	151	29	180	237	221
	2002	229	83	155	33	181	248	217
Buffalo	2006	338	106	202	55	147	269	231
	2007	318	102	189	59	148	272	231
Montgomery	2005	255	77	104	28	169	198	202
	2006	301	66	108	21	155	211	200
Maximum (µg/m^3)		339	106	202	59	213	272	231
Max @ 75m (µg/m^3)		92	75	44	30	100-140	140-170	120-150
Max Dist to NAAQS - Background (m)		60	60	150	120	<90	<100	<100

NOTE: NO_2 results reflect SCR controls on the completion equipment engines, with Tier 2 emissions used for all completion equipment, rig engines and compressors. Results are from the OLM option in AERMOD. See text for details.

Table 6.20 - Engine Tiers and Use in New York with Recommended Mitigation Controls Based on the Modeling Analysis (New July 2011)

Engine Type (year in place)	Sample Percent in Use	Reduction factors in Emissions	Control measures considered and determined "practical" based on availability, use practice and cost.
Drilling: Tier 1 - 1996 (five @ 500hp)	25	Others relative to Tier 1	Would need PM traps and SCR.
Drilling: Tier 2 - 2002	49	2.7 1.6	No PM controls nor SCR necessary for NAAQS.
Drilling: Tier 3 - 2006	22	2.7 2.6	No PM controls nor SCR necessary for NAAQS.
Drilling: Tier 4 - Interim (not mandated) - 2011	0	40 5.1	Would likely have PM traps built in. No SCR necessary.
Drilling: Tier 4 - 2014	0	40 23.	Would have PM traps and SCR built in.
Completion: Tier 1 - 2000 (15 @ 2250 Hp)	Assumed same as for drilling	Others relative to Tier 1	Based on modeling, propose not to allow Tier 1 engines. Alternative is traps/SCR, plus more mitigation.
Completion: Tier 2 - 2006		2.7 1.6	Would need PM trap and SCR.
Completion: Tier 4 Interim - 2011		5.3 3.5	Would likely have PM traps and SCR built in or would use in-cylinder control for PM.
Completion: Tier 4 - 2015		13 3.5	Would have PM traps and SCR built in.

Note: 3.5% of engines in use are Uncertified or Tier "0". These will not be allowed to be used in NY

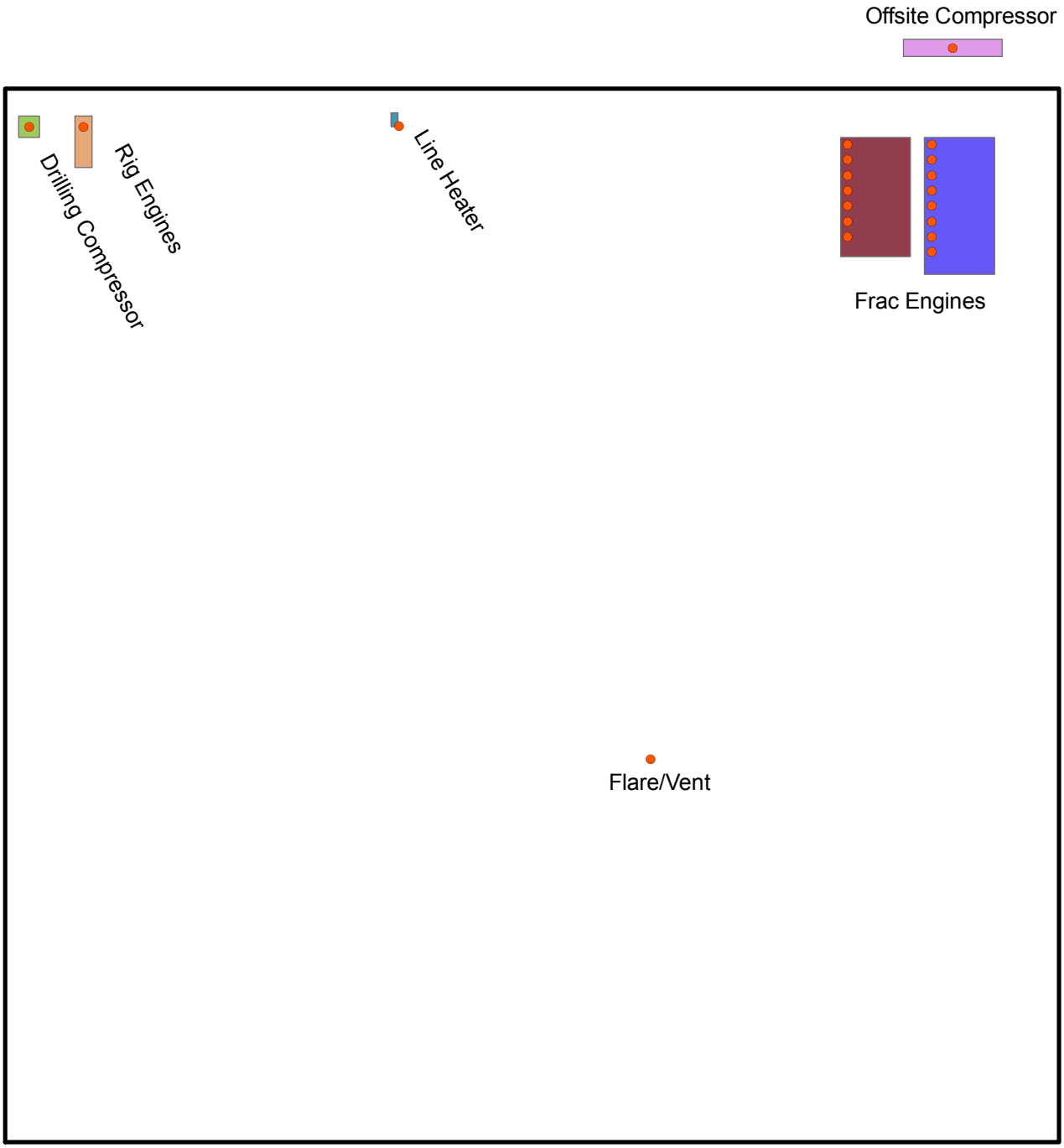


Figure 6.10- Location of Well Pad Sources of Air Pollution Used in Modeling

Buildings

- Drilling Compressor
- Frac Engines1
- Frac Engines2
- Line Heater
- Offsite Compressor
- Rig Engines

0 5 10 20 30 40 50 Meters

6.5.3 Regional Emissions of O_3 Precursors and Their Effects on Attainment Status in the SIP

This section addresses a remaining issue, as stressed by EPA Region 2[97] that the initial analysis did not provide a quantitative discussion of the potential regional emissions of the O_3 precursors, as contemplated in the Final Scoping for the 2009 draft SGEIS. The specific items relate to the impact of these drilling operations on the SIP for O_3 nonattainment purposes, as well as the impact of cumulative emissions from both stationary and mobile sources.

The initial analysis lacked information on the regional emissions of the cumulative well drilling activities in the whole of Marcellus Shale due to the lack of detail from industry on the likely number of wells to be drilled annually and associated emissions. It was determined that information and available data from similar shale development areas would not be suitable for a calculation of these emissions due to a variety of factors. Thus, the Department requested this emission information from industry and received the necessary data in the ALL/IOGA-NY Information Report referenced previously and in a follow-up request for mileage data for on-road truck traffic, as discussed below. The following narrative is intended to address concerns with the regional emissions as these relate to ozone attainment and similar SIP issues.

Attainment Status and Current Air Quality

The most recent nonattainment areas that have been designated by EPA are those for the 1997 8-hour ozone of 0.08 ppm (effectively 84 ppb), 1-hour ozone (0.12 ppm), annual and the 24-hour PM2.5 national ambient air quality standards (NAAQS) of 15 and 35 $\mu g/m^3$, respectively. In March 2008, EPA promulgated a revision of the 8-hour ozone NAAQS by setting the standard as 0.075 ppm. Nonattainment areas for the new standard have not as yet been established due to current efforts by EPA to reconsider a more restrictive NAAQS. EPA proposed its reconsideration of the 2008 ozone NAAQS in January 2010 taking comment on lowering the NAAQS to between 0.060 ppm and 0.070 ppm. EPA is expected to complete its reconsideration in July 2011.

Ozone and particulate matter are two of six pollutants regulated under the CAA as "criteria pollutants." Data from Department monitors through 2010 indicate that monitored air concentrations in the established nonattainment areas for O_3 and PM2.5, as well as in the area

[97] Comments of EPA Region 2 in letter from John Filippelli dated (12/30/09), pages 2-3.

underlain by the Marcellus Shale, do not exceed the currently applicable NAAQS. In addition, there are no areas in New York State that are classified as nonattainment for the remaining four criteria pollutants: CO, lead, NO_2 and SO_2. EPA has recently promulgated revisions to the lead, SO_2 and NO_2 NAAQS and has established new monitoring requirements for the lead and NO_2 NAAQS, as well as new modeling requirements for the SO_2 NAAQS. As a result of these new requirements, the Department cannot yet determine whether ambient air quality complies with these NAAQS values. However, the Department has proposed to EPA to classify the whole state as "unclassifiable" with respect to the NO_2 1-hour NAAQS and would have to submit a recommendation to EPA on SO_2 1-hour NAAQS. As data becomes available in the next few years, the Department would assess the data and recommend to EPA designation of all areas in the State as either attainment or nonattainment.

For O_3, the Department has a wealth of information to compare against the current, but delayed, 2008 NAAQS and the range of the reconsidered NAAQS. Under the 2008 Ozone NAAQS, current air quality in the Poughkeepsie-Newburgh, NYC and Jamestown metropolitan areas would make these areas nonattainment. If the O_3 NAAQS is set at the lower values proposed by EPA, more areas of the state, including those in the Marcellus Shale play, would also be nonattainment.

State Implementation Plans

The process by which states meet their obligations to improve air quality under the CAA, (for example, the applicable NAAQS for criteria pollutants) is established in SIPs. A major component of SIPs is the establishment of emission reduction requirements through the promulgation of new regulatory requirements that work to achieve those reductions. The combined effect of both state and federal requirements is to reduce the level of pollutants in the air and bring each nonattainment area into attainment. These requirements, which apply to both stationary and mobile sources, apply to both new and existing sources and are intended to limit emissions to a level that would not result in an exceedance of a NAAQS, thus preserving the attainment status of that area. In order to judge the potential effects of the projected O_3 and PM2.5 precursors in the Marcellus Shale on the SIP process, the Department has looked at the level of these emissions relative to the baseline emissions and has come to certain conclusions on the approach necessary to assure the goal of NAAQS compliance.

Projected Emissions and Current/Potential Control Measures

The primary contributors (emission sources) to ozone pollution include those that emit compounds known as "precursors" that result in the formation of ozone. The two most important precursors are NO_x and VOCs. PM2.5, another pollutant, is also directly emitted or formed from precursors, such as ammonia, sulfur oxides and NO_x. New York State and the federal government have promulgated emission rules that apply to the sources of these pollutants in order to protect air quality and prevent exceedances of the ambient air standards. In the case of Marcellus Shale gas resource development, most emissions resulting from natural gas well production activities are expected to come from the operation of internal combustion non-road engines used in drilling and hydraulic fracturing, as well as engines that provide the power for gas compression. Additional associated emissions occur with on road truck traffic used for transportation of equipment and hydraulic fracturing fluid components.

Engine emissions have long been known to be a significant source of air pollution. As a result, control requirements for these sources have been in place for many years, and have been updated as engine technology and control methods have improved. Regulations and limits exist on both the federal and state level, and effectively mitigate the effect of cumulative emissions on air quality and the SIP. In New York, these measures include:

Particulate Matter
Locomotive Engines and Marine Compression-Ignition Engines Final Rule
Heavy Duty Diesel (2007) Engine Standard
Part 227: Stationary Combustion Installations

Sulfur
Federal Nonroad Diesel Rule
6 NYCRR Part 225: Fuel Composition and Use

NO_x & VOCs
Part 217: Motor Vehicle Emissions
Part 218: Emission Standards for Motor Vehicles and Motor Vehicle Engines

Part 248: New York State Diesel Emissions Reduction Act (DERA)

Small Spark-Ignition Engines

Federal On-board Vapor Recovery

In addition, to address mobile sources emissions which might occur due to diesel trucks idling during the drilling operations, Subpart 217-3 of the New York State ECL specifically addresses this issue by limiting heavy duty vehicle idling to less than five consecutive minutes when the heavy duty vehicle is not in motion, except as otherwise permitted. Enforcement of this regulation is performed by Department Conservation Officers and violation can result in a substantial fine.

The above requirements for stationary sources apply statewide and not just in nonattainment areas due to New York's status as part of an Ozone Transport Region state. This differs from other areas such as the Barnett Shale project in which different standards apply inside and outside of the Dallas/Fort Worth nonattainment area. Furthermore, additional requirements and potential controls specific to the operations for the Marcellus Shale gas development were addressed in Section 6.5.1 with respect to the well pad and the compressor station (e.g., NSPS and NESHAPs requirements per 40 CFR 60, subpart ZZZZ and Part 63, subpart HH). Certain of these measures restrict the emissions of O_3 precursors to the maximum extent possible with current control measure. In addition to the mandatory requirements that are in place as a result of the above rules that directly affect the types of emissions that are expected with the development of Marcellus Shale gas resources, there are a number of other recommended measures that have been incorporated in previous sections to further reduce the emissions associated with these operations and mitigate the cumulative impacts:

1. NO_x emission controls (i.e., SCRs) and particulate traps on all diesel completion equipment engines and on older tier drilling engines (see section 6.5.2);

2. Condensate and oil storage tanks should be equipped with vapor recovery units (see section 6.5.1.5); and

3. The institution of a fugitive control program to prevent leaks from valves, tanks, lines and other pressurized production operations and equipment (see section on greenhouse gas remediation).

Use of controls for excess gas releases, such as flares by REC should be implemented wherever practicable (see section 6.5.2). In addition, other measures such as the use of more modern equipment and electric motors instead of diesel engines, where available, are recommended.

Regional NO_x and VOC Emission Estimates and Comparison to Estimates from another Gas-Producing Region

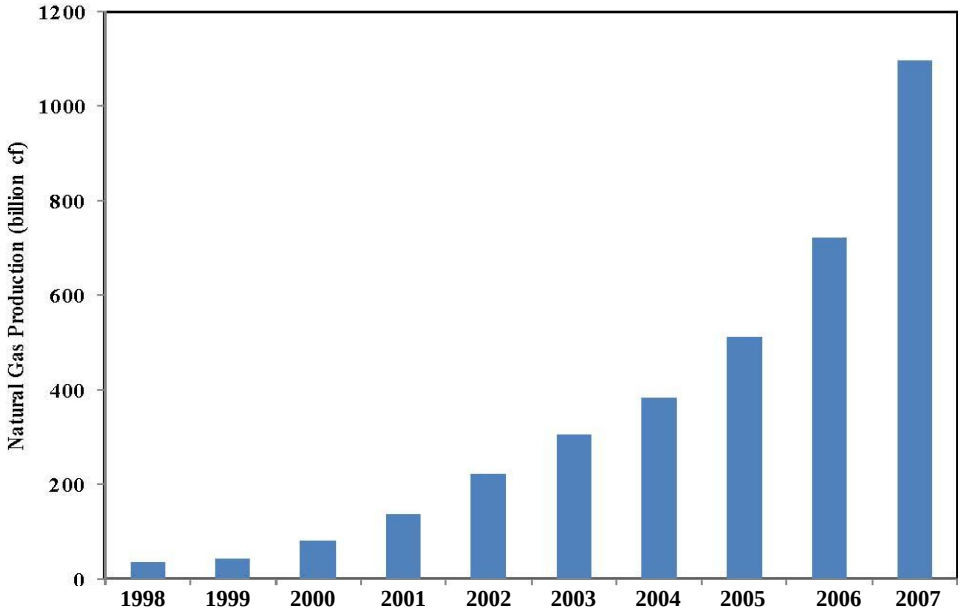
In order to assist the Department to develop a full understanding of the cumulative and regional emissions and impacts of developing the gas resources of the Marcellus Shale, available information from similar activities in other areas of the country has been reviewed. Notably, certain information from the Barnett Shale formation of north Texas, which has undergone extensive development of its oil and gas resources, was reviewed. The examination of the development of the Barnett Shale could be instructive in developing an approach to emissions control and mitigation efforts for the Marcellus Shale. As a result, the Department has examined one commonly referenced study and source of information on the regulation and control of air pollution from the development of the Barnett Shale.

First, the development of the gas resources of the Marcellus Shale, as with the Barnett Shale, not be spatially distributed evenly across the geographic extent of the region, but would likely concentrate in different areas at different times, depending on many factors and limitations, including the price of natural gas at any given moment, the ease of drilling one area versus another, and other legal/environmental constraints such as potential drilling in watersheds. As such, industry cannot project at this time as to where impacts may concentrate regionally within the Marcellus Shale region. Furthermore, well development would occur over time, wherein initially there would be a "ramping-up" period, followed by a nominal "peak" drilling period, and then a leveling off or dropping off period. Some of these factors and caveats are discussed in the ALL/IOGA-NY Information Report.

Thus, the cumulative impacts of gas well drilling within the Marcellus Shale would also vary depending on what point in time those impacts are measured as the development of the gas resource expands over time. As an example of how well development proceeded in the Barnett Shale, the Figure 6.11 indicates that gas production rose dramatically from 1998-2007. This chart is being used by the Department for illustration purposes only to indicate the timeframes

which might be involved in the Marcellus development and not as an actual indication of expected development. Preliminary information from Pennsylvania indicates a more rapid increase in gas well drilling and production.

Figure 6.11 - Barnett Shale Natural Gas Production Trend, 1998-2007[98]



As drilling activities "ramp up," the potential for greater environmental impacts likewise increase. In estimating the air emissions of drilling in the Marcellus Shale, a worst case (conservative) scenario of drilling and development was developed by IOGA-NY in response to an information request from the Department. The estimates are provided in the ALL/IOGA-NY Information Report. There are a number of caveats associated with these estimates so the absolute magnitudes of emissions should be interpreted accordingly. However, an estimate of worst case emissions are projected for the maximum likely number of wells (2216) to be drilled in the Marcellus Shale for the "peak" year of operations and the emission factors and duration of operations provided in the previous industry report (8/26/09) used in the modeling assessment.

[98] Taken from Armendariz (SMU), 2009, p. 2.

Some of the factors which were included in the estimates noted in the ALL/IOGA-NY Information Report include:

- Average emission rates for dry gas are used for every well for every phase of development;
- Maximum number of wells (both horizontal and vertical) in any year;
- No credit is taken for any mitigation measures, permit emissions controls, or state and federal regulatory requirements that are expected to reduce these estimates;
- Drilling emissions are conservatively estimated at 25 days for the horizontal wells;
- Heater emissions are included year-round in the production estimates; however,they would be seasonal and would take place during the non-ozone season;
- Off-pad compressor emissions are included in the production estimates; however, it is anticipated that most well pads would not include a compressor;
- No credit is taken for the rolling nature of development; i.e., that all wells would not be drilled or completed at the same time, on the same pad;
- No credit is taken for improved nonroad engine performance and resultant reduced NO_x emissions from the higher tier engines that would be phased in over time; and
- No credit is taken for reduced emission completions which would significantly reduce flaring and hence related NO_x and VOC emissions.

The ALL/IOGA-NY Industry Information Report predicted the ozone precursor emissions depicted in Table 6.21.

Table 6.21 - Predicted Ozone Precursor Emissions (Tpy)

	Drilling	Completion	Production	Totals
Horizontal - NO_x	8,376	5,903	8,347	22,626
Vertical - NO_x	409	345	927	1,681
Total NO_x	8,785	6,248	9,274	24,307
Horizontal - VOC	352	846	5,377	6,575
Vertical - VOC	17	81	597	695
Total VOC	369	927	5,974	7,270

It is seen that the total for NO_x emissions for the horizontal wells is made up of 37% each from drilling and production and 26% from completion. It is to be noted that for the latter emissions, about half is associated with potential flaring operations. For VOC emissions for the horizontal wells, the production sources dominate (82% of total). This is related to the dehydrator emissions assumed to operate for a full year. It is also noted that the completion VOC emissions are due to venting and flaring. Based on the above numbers, IOGA-NY concluded the impact from the development of the Marcellus at a worst-case peak development rate would add 3.7% to existing NO_x emissions on a statewide basis. This was based on the 2002 baseline emission inventory (EI) year used in New York's 2007 SIP demonstration for the 8-hr ozone standard[99]. A more germane comparison would be to the "upstate" area emissions where Marcellus Shale area is located. This comparative increase would be 10.4% for the same EI year. These upstate area emissions exclude the nine-county New York ozone nonattainment area, as well as the counties north and east of the area underlain by the Marcellus Shale.

The total NO_x emissions increase from this example is deemed significant, but does not account for the number of mitigation measures imposed and recommended in the revised SGEIS. For example, the use of SCR control to reduce NO_x emissions by 90% from the completion equipment engines would reduce the completion emission by about half, while the minimization of flaring operations by the use of REC would reduce the rest of these completion emissions down to a very small value which would significantly reduced the relative percentage. In addition, as noted by the IOGA-NY Information Report, the production sources used in the estimates of NO_x emissions are not likely to be used the full year and might not be even needed at many wells. Furthermore, the estimated drilling emissions assume the maximum number of days would be needed for each well and the associated use of older tier engines throughout the area and over the long-term. Thus, the relative percent of Marcellus well drilling emissions to the existing baseline is highly likely to be substantially less than the value above using the worst case estimates.

The IOGA-NY also concluded that the total VOC emissions of 7,270 Tpy from the development of the Marcellus Shale would add 0.54% to existing VOC emissions on a statewide basis. Using

[99] Ozone Attainment Demonstration for NY Metro Area - Final Proposed Revision, Appendix B, pp. 10-11 http://www.dec.ny.gov/chemical/37012.html.

the same baseline EI year as for NO_x, the relative increase for VOCs would be 1.3%. This increase is deemed small and also does not account for recommended mitigation measures such as the minimization of gas venting by REC.

The above NO_x and VOC relative emission comparisons do not include the contribution from the on road truck traffic associated with Marcellus Shale operations and which had to be estimated by the Department. The ALL/IOGA-NY Information Report included the light and heavy truck trips, but not the associated average mileage which is necessary to calculate emissions. Thus, the Department requested an average Vehicle Miles Traveled (VMT) for the two truck types and ALL consulting provided the data in a response letter.[100] Based on this information, the Department projected the NO_x and VOC emissions from on road truck as discussed in the next subsection.

Effects of Increased Truck Traffic on Emissions

The initial modeling analysis did not address on-road mobile source emissions resulting from the drilling operations, specifically, diesel truck emissions, except at the well pad. The Department has analyzed the impact of increased emissions from truck traffic in the Marcellus Shale affected counties. As part of this analysis, the Department utilized estimates of VMT provided by ALL Consulting/IOGA-NY in response to the Department's information request to determine the environmental impacts of project related truck emissions. Industry estimated that the weighted average one way VMT for both light and heavy duty trucks to be approximately 20 to 25 miles for both horizontal and vertical wells.

The Department used these estimated average VMT for heavy-duty and light-duty trucks and the number of truck trips contained in the ALL/IOGANY Information Report to calculate the total additional VMT associated with drilling activities. These VMT, along with other existing New York-specific data were input to the EPA's Motor Vehicle Emission Simulator (MOVES) model to estimate NO_x and VOC emissions for the various truck activities. EPA Region 2 commented on the SGEIS and requested the use of the MOVES model. As EPA's approved mobile source model, MOVES incorporates revised EPA emission factors for various on-road mobile source activities and associated pollutants. The resulting emissions support a comparison of how traffic

directly related to the drilling operations impacts the overall mobile emissions that normally would occur throughout the Marcellus Shale drilling area.

The estimated emissions of NO_x and VOCs (and well as other pollutants) that result from the additional light and heavy duty truck traffic expected with Marcellus well drilling are detailed in Appendix 18C. The emissions for the counties in the area underlain by the Marcellus Shale are presented for both the existing baseline activities as well as those associated with the drilling activities. In addition, the absolute and percent differences which represent the additional truck emissions are shown.

The results show that the total NO_x and VOC emissions are estimated to be 687 and 70 Tpy, respectively, and are expected to increase the existing baseline emissions by 0.66% and 0.17%. The maximum increase for any pollutant is 0.8%. These increases are deemed very small. In addition, the traffic related NO_x and VOC emissions are noted to be small fractions of the corresponding increased emissions due to other activities associated with gas drilling, as summarized in the last subsection. For example, the traffic related NO_x emissions are about 3% of the total NO_x emissions given in the above mentioned summary table. A simple estimate of traffic related emissions of PM2.5 per pad, using the total emissions and the number of maximum wells is shown in Appendix 18C to be 0.01 Tpy which is comparable to the previously estimated pad specific PM2.5 emissions noted in the modeling section which was estimated with the EPA MOBILE6 model.

Based on these results, the Department concluded that the estimated truck related emissions would be captured during the standard development of the mobile inventories for the SIP. These estimates are also noted to be within the variability associated with the MOVES model inputs.

Comparison to Barnett Shale Emission

A referenced report[101] on the Barnett Shale oil and gas production prepared by Southern Methodist University (SMU) for the Environmental Defense Fund (EDF) has been noted as a source of emission calculation schemes and resultant regional emissions for that region of Texas. In terms of the projected emissions of NO_x and VOCs, while caution should be exercised in

making comparisons between the two areas, a picture of emissions from the Barnett Shale may be a useful point of departure for understanding the magnitude and types of emissions to be expected with the development of the Marcellus Shale. The Department has not undertaken a review of the rationale or the methodologies used in the SMU report and is also aware of the Texas Commission on Environmental Quality (TCEQ)'s critique of the report.[102] Since the report, TCEQ has undertaken a detailed emission inventory development program to better characterize the sources and to quantify the corresponding emissions.

For the present purposes, it is necessary to provide a brief outline of the potential differences between the gas development activities and associated sources between the Barnett report and the industry projections for the Marcellus Shale. For example, the SMU report provided the relative amount of emissions from different source categories and corresponding NO_x and VOC emissions, as presented in Table 6.22 below. For comparison, the industry-provided emissions summarized above are 66.7 and 20 tons per day (Tpd) for NO_x and VOCs, respectively. However, the latter do not include some of the sources tabulated in the SMU report such that a straightforward comparison is not possible. Nonetheless, the SMU report notes that the largest group of VOC sources was condensate tank vents. Table 6.22 also indicates that fugitive emissions from production operations have a significant contribution to the VOC totals.

Table 6.22 - Barnett Shale Annual Average Emissions from All Sources[103]

Source	2007 Pollutants, Tons per day(Tpd)		2009 Pollutants, Tons per day (Tpd)	
	NOx	VOC	NOx	VOC
Compressor Engine Exhausts	51	15	46	19
Condensate And Oil Tanks	0	19	0	30
Production Fugitives	0	17	0	26
Well Drilling and Completion	5.5	21	5.5	21
Gas Processing	0	10	0	15
Transmission Fugitives	0	18	0	28
Total Daily Emissions (Tpd)	**56**	**100**	**51**	**139**

[103] Adapted from Armendariz (SMU), 2009 p. 24.

These might explain the differences in VOC emissions in that industry does not expect to use condensate tanks in New York due to the dry gas encountered in the Marcellus Shale. In addition, these tank emissions, if used, would be controlled by vapor recovery systems as noted in Section 6.5.2. In addition, all efforts would need to be made by industry to minimize fugitive emissions as recommended in the greenhouse gas emission mitigations section which would reduce concomitant VOC emissions.

The SMU report also provides charts which compare the total NO_x plus VOC emissions from the Barnett oil and gas sources to totals from on-road source categories in the Dallas-Fort Worth area, concluding that the former are larger than the on road emissions in some respects. However, these comparisons are not transferrable to the Marcellus Shale situation in New York not only because VOC emissions dominate these totals, but also since the comparisons are to a specific regional mix of sources not representative of the situation to be encountered in New York. On face value, the absolute magnitude of these total emissions is much larger than even a "worst-case" scenario for the Marcellus Shale.

Again, no firm predictions or projections can be made at this time as to where or when gas drilling impacts may concentrate regionally within the Marcellus Shale, but the Department would continue to avail itself of the knowledge and lessons learned from similar regional shale gas development projects in other parts of the country.

Further Discussions and Conclusions

There are stringent regulatory controls already in place for controlling emissions from stationary and mobile sources in New York. With additional required emission controls recommended in the revised SGEIS for the operations associated with drilling activities, coupled with potential deployment of further emission controls arising from upcoming O_3 SIP implementation actions, the Department is confident that the effect of cumulative impacts from the development of gas resources in the multi-county area underlain by the Marcellus Shale would be adequately mitigated. Thus, the Department would be able to continue to meet attainment goals that it has set forth in cooperation with EPA. In addition to eliminating the use of uncertified and certain older tier engines and requiring specific mitigation measures to substantially reduce PM and NO_x emissions in order to meet NAAQS, the Department would review the need for certain additional

mitigation prior to finalizing the SGEIS. As part of the information, the Department is seeking from industry an implementation timeline to expedite the use of higher tier drilling and completion equipment engines in New York. Furthermore, as the Department readies for the soon to be announced revised O_3 NAAQS and potential revisions to the PM2.5 NAAQS, the need for imposing further controls on drilling engines not being currently required to be equipped with PM traps and SCR would be revisited. If it is determined that further mitigation is necessary, further controls would be required. The review would consider the relatively high contribution to regional emissions of NO_x from the drilling engines and result from regional modeling of O_3 precursors which would be performed in preparation of the Ozone SIP.

Regional photochemical air quality modeling is a standard tool used to project the consequences of regional emission strategies for the SIP. The application of these models is very time and resource intensive. For example, these require detailed information on the spatial distribution of the emissions of various species of pollutants from not only New York sources, but from those in neighboring states in order to properly determine impacts of NO_x and VOC precursor emissions on regional O_3 levels. At present, detailed necessary information for the proper applications of this modeling exercise is lacking. However, as part of its commitment to the EPA, and in cooperation with the Ozone Transport Commission to consider future year emission strategies for the Ozone SIP, the Department would include the emissions from Marcellus Shale operations in subsequent SIP modeling scenarios. As such, properly quantified emissions specifically resulting from Marcellus Shale operations would be included in future SIP inventories to the extent that the information becomes available. Interim to this detailed modeling, the Department would perform a screening level regional modeling exercise by adding the projected emissions associated with New York's portion of the Marcellus Shale drilling to the baseline inventory which is currently being finalized. This modeling would guide the Department's finalization of the SGEIS. In addition to the availability of the regional modeling results, the Department has recommended that a monitoring program be undertaken by industry to address both regional and local air quality concerns as discussed in the next section.

6.5.4 Air Quality Monitoring Requirements for Marcellus Shale Activities

In order to fully address potential for adverse air quality impacts beyond those analyzed in the SGEIS relate to associated activities which are either not fully known at this time or verifiable by

the assessments to date, it has been determined that a monitoring program would be undertaken. For example, the consequences of the increased regional NO_x and VOC emissions on the resultant levels of ozone and PM2.5 cannot be fully addressed by only modeling at this stage due to the lack of detail on the distribution of the wells and compressor stations. In addition, any potential emissions of certain VOCs at the well sites due to fugitive emissions, including possible endogenous level, and from the drilling and gas processing equipment at the compressor station (e.g. glycol dehydrators) are not fully quantifiable. Thus, it has been determined that an air monitoring plan is necessary to address these regional concerns as well as to verify the local-scale impact of emissions from the three phases of gas field development: drilling, completion and production. The monitoring plan discussed herein is determined to be the level of effort necessary to assure that the overall activities of the gas drilling in the Marcellus Shale would not cause adverse regional or local air quality impacts. The monitoring is an integral component of the requirements for industry to undertake to satisfy the SEQRA findings of acceptable air quality levels.

Based on the results from the Department's assessments of gas production emissions, and in consideration of the well permitting approach and the modeling analysis, an air monitoring plan has been developed to address the level of effort necessary to determine and distinguish both background and drilling related concentrations of pertinent pollutants. In addition, a review of previous monitoring activities for shale drilling conducted by the TCEQ[104] and the PADEP[105] was undertaken to better characterize the monitoring needs and instrumentation. The approach selected as best suited for monitoring for New York Marcellus Shale activities combines a regional and local scale monitoring effort aimed at different aspects of emission impact characterization. These two efforts are as follows:

1) Regional level monitoring: In order to assess the impact of regional emissions of precursors including VOCs and NO_x, monitoring for O_3 and PM2.5 would need to be conducted at two locations. One would be a "background" site and another would need to be placed at a downwind location sited to reflect the likely impact area from the atmospheric transport and conversion of the precursors into secondary pollutants. These would enhance the current Department O_3 monitoring in the area. These sites would also

[105] See: http://www.dep.state.pa.us/dep/deputate/airwaste/aq/toxics/toxics.htm.

need to be equipped with air toxics monitors so that pollutant levels can be compared to each other and to other existing sites; and

2) Near-field/local scale monitoring at various locations in the Marcellus Shale: This monitoring can be intermittent but would be carried out in areas expected to be directly impacted by one or more wells and compressor stations. The data from this monitoring effort would be used to assess the significance of the various known drilling related activities and to identify specific pollutants that may pose a concern. In addition, possible fugitive emissions of certain VOCs should be monitored to locate and mitigate emissions, beyond those necessary for worker safety purposes. The Department has identified specific well drilling activities and pollutants which have been found to be related to these activities and recommends that these are included in the near-field monitoring program See Table 6.23.

Table 6.23 - Near-Field Pollutants of Concern for Inclusion in the Near-Field Monitoring Program (New July 2011)

Well Pad and Related Activity	Pollutants of Concern
Drilling and Completing (completion equipment) Engines	1-Hour NO_2 and 24-hour PM2.5
Gas venting (could be potentially mitigated by REC)	BTEX, formaldehyde, H_2S or another odorant.
Glycol dehydrator and condensate tanks at either the well pad or at the compressor station (if wet gas is present)	BTEX, benzene, and formaldehyde.
Leaks and fugitives	Methane and VOC emissions

The near-field local scale monitoring is expected to be performed periodically with field campaigns typically lasting a few days when activities are occurring at the well pad and when the compressor station is operational and operating near maximum gas flow conditions. Since the scope of gas related emissions from one area of operation to another is limited, it is anticipated that after a few intensive near-field monitoring campaigns, adequate and representative data would be gathered to understand the potential impacts of the various phases of gas drilling and production. At that point, the level of effort and the further need for the short term monitoring would be evaluated. In addition to the near-field monitoring, it is anticipated that a similar level of short term monitoring would be conducted on a limited basis at a nearby residential location or in a representative community setting to determine the actual exposure to the public.

However, based on the results from the TCEQ and PADEP monitoring, the potential for finding relatively higher concentrations would likely be in close proximity to the well pad and compressor station.

It is expected that the cost and implementation of this monitoring would be the responsibility of industry. To carry out this monitoring plan, a specific set of monitoring equipment and procedures would be necessary. Some of these deviate from the "traditional" compliance oriented monitoring plans; for example, due to the relatively short term and intensive monitoring required at various locations of activities, the suggested approach would be to operate a mobile equipped unit. Department monitoring staff has longstanding expertise in conducting this type of monitoring over the last two decades. The most recent local-scale monitoring project carried out by the Department was the Tonawanda Community Air Quality Monitoring project.

As an alternative to industry implementing this monitoring plan in a repetitive company by company stepwise fashion as gas development progresses, it is the Department 's preference that the monitoring be undertaken by the Department's Division of Air Resources monitoring staff. However, this alternative cannot be carried out with current Department staff or equipment and would only be possible with additional staff and equipment resources. This alternative is preferred from a number of standpoints, including:

1) Overall program cost would be reduced because each operator would not be responsible for their own monitoring program. Even if the operators are able to hire a common consultant, there would be complexities in allocation the work to various locations;

2) The Department would not have to "oversee" contractor work hired either by industry or by the Department;

3) The timing and production of data analysis would be simplified and reports would be under the Department's control;

4) The Department can utilize certain existing monitor sites for the regional monitoring program;

5) The central coordination would minimize the overall costs of the monitoring; and

6) The Department would have the ability to monitor near the compressor stations which might not be within the control of the drilling operators.

If the Department was to receive the necessary funding and staff to conduct the monitoring, the following table identifies some of the specifics associated with the expected level of monitoring.

Table 6.24 - Department Air Quality Monitoring Requirements for Marcellus Shale Activities (New July 2011)

Monitoring Parameters	Purpose of Monitoring	Proposed Scheme and Instrumentation Needs.
Regional scale O_3, PM2.5, NO_2 and add toxics.	To assess the impact of regional VOC and NO_x emissions on Ozone and PM2.5 levels.	Add a Department monitoring trailer to a new site in Binghamton, plus add toxics at existing Pinnacle site and the new site.
Local/near field monitoring for BTEX, methane, formaldehyde, sulfur (plus O_3, PM2.5 and NO_2)	To assess impacts close-by to well pads, compressor stations and associated equipment (e.g. glycol dehydrator, condensate tanks). Also, limited follow-up in nearby communities.	Purpose-built vehicle with generators as a mobile laboratory. A less desirable alternative is a "stationary" trailer which would need days for initialization.
Intermittent methane and VOC leaks from sources (e.g. fugitive)	To detect and initiate company mitigation of fugitive leaks.	Forward Looking Infrared (FLIR) cameras- one for routine inspections, second to respond to complaints.
"Saturated" BTEX and other VOC species monitoring	To verify the spatial extent of the mobile monitoring results.	Manually operated canister samplers which can be analyzed for 1 to 24-hour concentrations of various toxics.

This monitoring would be the minimum level of effort necessary to properly characterize the air quality in the affected areas for the pollutants which have been identified as possibly requiring mitigation measures or having an effect due to regional emissions. In developing the monitoring approach, Department staff has reviewed the results of the monitoring conducted by TCEQ and PADEP to learn from their experiences, as well as from our own toxics monitoring experiences. To that end, it was determined that a mobile unit with the necessary equipment which would best perform the monitoring for both near-field and representative community based areas. The use of an open path Fourier-transform Infrared (FTIR) spectroscopy used in the PADEP study was evaluated, but deemed unnecessary due to the fact that the mobile unit would be detecting the same pollutants at lower more health relevant detection levels. To overcome the potential concern with spatial representativeness of the near-field monitoring program, the Department recommends augmenting the mobile vehicle with manually placed canisters which could be used on a limited basis to provide a wider areal coverage during the various activities and as a secondary confirmation of the mobile unit results.

The monitoring plan outlined above would be used to address public concerns with the actual pollutant levels in the areas undergoing drilling activities. In addition, it could assist in the identification of the level of conservatism used in the emission estimates for the well pads, the Marcellus area region, and modeling analysis which have been noted as concerns.

6.5.5 Permitting Approach to the Well Pad and Compressor Station Operations

The discussions in subsection 6.5.1.9 of the regulatory applicability section outline the approach which the Department has determined is in line with regulatory permitting requirements and which best address the issues surrounding the air permitting of the three phases of gas drilling, completion and production. The use of the compressor station air permit application process to determine the regulatory disposition and necessary control measures on a case-by-case basis is in keeping with the approach taken throughout the country, as affirmed by EPA in a number of instances. This review process would allow the proper determination of the applicable regulations to both the compressor station and all associated well operations in defining the facility to which the requirements should apply. In concert with the strict operational restrictions determined in the modeling section necessary for the drilling and completion equipment engines, the self-imposed operational and emission limits put forth by industry would assure compliance

with all applicable standards. To further assure that these restrictions are adhered to for all well operations, a set of necessary conditions identified in Section 7.5.3 and Appendix 10 will be included in DMN well permits.

DMN Well Drilling Permit Process Requirements

Based on industry's self-imposed limitations on operations and the Department's determination of conditions necessary to avoid or mitigate adverse air quality impacts from the well drilling, completion and production operations, mitigation noted in Chapter 7 would be imposed in the well permitting process.

6.6 Greenhouse Gas Emissions

On July 15, 2009, the Department's Office of Air, Energy and Climate issued its *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*.[106] The policy reflected in the guide is used by Department staff in reviewing an environmental impact statement (EIS) when the Department is the lead agency under SEQRA and energy use or GHG emissions have been identified as significant in a positive declaration, or as a result of scoping, and, therefore, are required to be discussed in an EIS. Following is an assessment of potential GHG emissions for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high-volume hydraulic fracturing.

SEQRA requires that lead agencies identify and assess adverse environmental impacts, and then mitigate or reduce such impacts to the extent they are found to be significant. Consistent with this requirement, SEQRA can be used to identify and assess climate change impacts, as well as the steps to minimize the emissions of GHGs that cause climate change. Many measures that would minimize emissions of GHGs would also advance other long-established State policy goals, such as energy efficiency and conservation; the use of renewable energy technologies; waste reduction and recycling; and smart and sustainable economic growth. The *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement* is

[106] http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf.

not the only State policy or initiative to promote these goals; instead, it furthers these goals by providing for consideration of energy conservation and GHG emissions within EIS reviews.[107]

The goal of this analysis is to characterize and present an estimate of GHG emissions for the siting, drilling and completion of 1) single vertical well, 2) single horizontal well, 3) four-well pad (i.e., four horizontal wells at the same site), and respective first-year and post first-year emissions of CO_2, and other relative GHGs, as both short tons and as carbon dioxide equivalents (CO_2e) expressed in short tons, for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. In addition, the major contributors of GHGs are to be identified and potential mitigation measures offered.

6.6.1 Greenhouse Gases

The two most abundant gases in the atmosphere, nitrogen (comprising 78% of the dry atmosphere) and oxygen (comprising 21%), exert almost no greenhouse effect. Instead, the greenhouse effect comes from molecules that are more complex and much less common. Water vapor is the most important greenhouse gas, and CO_2 is the second-most important one.[108] Human activities result in emissions of four principal GHGs: CO_2, methane (CH_4), nitrous oxide (N_2O) and the halocarbons (a group of gases containing fluorine, chlorine and bromine). These gases accumulate in the atmosphere, causing concentrations to increase with time. Many human activities contribute GHGs to the atmosphere.[109] Whenever fossil fuel (coal, oil or gas) burns, CO_2 is released to the air. Other processes generate CH_4, N_2O and halocarbons and other GHGs that are less abundant than CO_2, but even better at retaining heat.[110]

6.6.2 Emissions from Oil and Gas Operations

GHG emissions from oil and gas operations are typically categorized into 1) vented emissions, 2) combustion emissions and 3) fugitive emissions. Below is a description of each type of emission. For the noted emission types, no distinction is made between direct and indirect emissions in this analysis. Further, this GHG discussion is focused on CO_2 and CH_4 emissions

[107] http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf.

[108] http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf.

[109] http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf.

[110] http://www.dec.ny.gov/energy/44992.html.

as these are the most prevalent GHGs emitted from oil and gas industry operations, including expected exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. Virtually all companies within the industry would be expected to have emissions of CO_2 - and, to a lesser extent, CH_4 and N_2O - since these gases are produced through combustion. Both CH_4 and CO_2 are also part of the materials processed by the industry as they are produced in varying quantities, from oil and gas wells. Because the quantities of N_2O produced through combustion are quite small compared to the amount of CO_2 produced, CO_2 and CH_4 are the predominant oil and gas industry GHGs.[111]

6.6.2.1 Vented Emissions

Vented sources are defined as releases resulting from normal operations. Vented emissions of CH_4 can result from the venting of natural gas encountered during drilling operations, flow from the flare stack during the initial stage of flowback, pneumatic device vents, dehydrator operation, and compressor start-ups and blowdowns. Oil and natural gas operations are the largest human-made source of CH_4 emissions in the United States and the second largest human-made source of CH_4 emissions globally. Given methane's role as both a potent greenhouse gas and clean energy source, reducing these emissions can have significant environmental and economic benefits. Efforts to reduce CH_4 emissions not only conserve natural gas resources but also generate additional revenues, increase operational efficiency, and make positive contributions to the global environment.[112]

6.6.2.2 Combustion Emissions

Combustion emissions can result from stationary sources (e.g., engines for drilling, hydraulic fracturing and natural gas compression), mobile sources and flares. Carbon dioxide, CH_4, and N_2O are produced and/or emitted as a result of hydrocarbon combustion. Carbon dioxide emissions result from the oxidation of the hydrocarbons during combustion. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, and this conversion is relatively independent of the fuel or firing configuration. Methane emissions may result due to incomplete

[111] IPIECA and API, December 2003, p. 5-2.

[112] http://www.epa.gov/gasstar/documents/ngstar_mktg-factsheet.pdf.

combustion of the fuel gas, which is emitted as unburned CH_4. Overall, CH_4 and N_2O emissions from combustion sources are significantly less than CO_2 emissions.[113]

6.6.2.3 Fugitive Emissions

Fugitive emissions are defined as unintentional gas leaks to the atmosphere and pose several challenges for quantification since they are typically invisible, odorless and not audible, and often go unnoticed. Examples of fugitive emissions include CH_4 leaks from flanges, tube fittings, valve stem packing, open-ended lines, compressor seals, and pressure relief valve seats. Three typical ways to quantify fugitive emissions at a natural gas industry site are 1) facility level emission factors, 2) component level emission factors paired with component counts, and 3) measurement studies.[114] In the context of GHG emissions, fugitive sources within the upstream segment of the oil and gas industry are of concern mainly due to the high concentration of CH_4 in many gaseous streams, as well as the presence of CO_2 in some streams. However, relative to combustion and process emissions, fugitive CH_4 and CO_2 contributions are insignificant.[115]

6.6.3 Emissions Source Characterization

Emissions of CO_2 and CH_4 occur at many stages of the drilling, completion and production phases, and can be dependent upon technologies applied and practices employed. Considerable research – sponsored by the API, the Gas Research Institute (GRI) and the EPA – has been directed towards developing relatively robust emissions estimates at the national level.[116] The analytical techniques and emissions factors, and mitigation measures, developed by the these agencies were used to evaluate GHG emissions from activities necessary for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high-volume hydraulic fracturing.

In 2009, NYSERDA contracted ICF International (ICF) to assist with supporting studies for the development of the SGEIS. ICF's work included preparation of a technical analysis of potential impacts to air in the form of a report finalized in August 2009.[117] The report, which includes a

[113] API 2004; amended 2005. p 4-1.
[114] ICF Task 2, 2009, p. 21.
[115] IPIECA and API, December 2003., p. 5-6.
[116] New Mexico Climate Change Advisory Group, November 2006, , pp. D-35.
[117] ICF Task 2, 2009.

discussion on GHGs, provided the basis for the following in-depth analysis of potential GHGs from the subject activity. ICF's referenced study identifies drilling, completion and production operations and equipment that contribute to GHG emission and provides corresponding emission rates, and this information facilitated the following analysis by identifying system components on an operational basis. As such, wellsite operations considered in the SGEIS were divided into the following phases for this GHG analysis:

- Drilling Rig Mobilization, Site Preparation and Demobilization;
- Completion Rig Mobilization and Demobilization;
- Well Drilling;
- Well Completion (includes hydraulic fracturing and flowback); and
- Well Production.

Transport of materials and equipment is an integral component of the oil and gas industry. Simply stated, a well cannot be drilled, completed or produced without GHGs being emitted from mobile sources. The estimated required truck trips per well and corresponding fuel usage for the below noted phases requiring transportation, except well production, were provided by industry.[118]

Drilling Rig Mobilization, Site Preparation and Demobilization

Drill Pad and Road Construction Equipment
Drilling Rig
Drilling Fluid and Materials
Drilling Equipment (casing, drill pipe, etc.)

Completion Rig Mobilization and Demobilization

Completion Rig

[118] ALL Consulting, 2011, Exhibits 19B, 20B.

Well Completion

Completion Fluid and Materials
Completion Equipment (pipe, wellhead)
Hydraulic Fracturing Equipment (pump trucks, tanks)
Hydraulic Fracturing Water
Hydraulic Fracturing Sand
Flow Back Water Removal

Well Production[119]

Production Equipment (5 – 10 Truckloads)

Mileage estimates for both light duty and heavy duty trucks were used to determine total fuel usage associated with site preparation and rig mobilizations, well completion and well production activities. As further discussed below, when actual or estimated fuel use data was not available, VMT formed the basis for estimating CO_2 emissions.

Three distinct types of well projects were evaluated for GHG emissions as follows:

- Single-Well Vertical Project;
- Single-Well Horizontal Project; and
- Four -Well Pad (i.e., four horizontal wells at the same site).

For rig and equipment mobilizations for each of the project types noted above, it was assumed that all work involving the same activity would be finished before commencing a different activity. In other words, the site would be prepared and the drilling rig mobilized, then all wells (i.e., one or four) would be drilled, followed by the completion of all wells (i.e., one or four) and subsequent production of all wells (i.e., one or four). A number of operators have indicated to the Department that activities on multi-well pads would be conducted sequentially, whenever possible, to realize the greatest efficiency but the actual order of work events and number of wells on a given pad may vary. Nevertheless, four wells was the number of wells selected for

[119] NTC Consultants. *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, September 2009.

the multi-well pad GHG analysis because industry indicated that number would be the maximum number of wells drilled at the same site in any 12 consecutive months.

Stationary engines and equipment emit CO_2 and/or CH_4 during drilling and completion operations. However, most are not typically operating at their full load every hour of each day while on location. For example, certain engines may be shut down completely or operating at a very low load during bit trips, geophysical logging or the running of casing strings. Consequently, for the purpose of this analysis and as noted in Table 6.25 and Table 6.26 below, it was assumed that engines and equipment for drilling and completion operations generally operate at full load for 50% of their time on location. Exceptions to this included engines and equipment used for hydraulic fracturing and flaring operations. Instead of relying on an assumed time frame for operation for the many engines that drive the high-pressure high-volume pumps used for hydraulic fracturing, an average of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring Pennsylvania and West Virginia was used.[120] In addition, flaring operations and associated equipment were assumed to be operating at 100% for the entire estimated flaring period.

Table 6.25 - Assumed Drilling & Completion Time Frames for Single Vertical Well (New July 2011)

Operation	**Estimated Duration (days / hrs.)**	**Assumed Full Load Operational Duration for Related Equipment (days / hrs.)**
Well Drilling	13 / 312	6½ / 156
Completion	¼ / 6 (hydraulic fracturing) 1 / 24 (rig)	¼ / 6 (hydraulic fracturing) ½ / 12 (rig)
Flaring	3 / 72	3 / 72

Table 6.26 - Assumed Drilling & Completion Time Frames for Single Horizontal Well (Updated July 2011)

Operation	**Estimated Duration (days / hrs.)**	**Assumed Full Load Operational Duration for Related Equipment (days / hrs.)**
Well Drilling	25 / 600	12½ / 300
Completion	2 / 48 (hydraulic fracturing) 2 / 48 (rig)	2 / 48 (hydraulic fracturing) 1 / 24 (rig)
Flaring	3 / 72	3 / 72

[120] ALL Consulting, 2009, Table 11, p. 10.

Stationary engines and equipment also emit CO_2 and/or CH_4 during production operations. In contrast to drilling and completion operations, production equipment generally operates around the clock (i.e., 8,760 hours per year) except for scheduled or intermittent shutdowns.

6.6.4 Emission Rates

The primary reference for emission rates for stationary production equipment considered in this analysis is the GRI's *Methane Emissions from the Natural Gas Industry*. Table GHG-1 "Emission Rates for Well Pad" in Appendix 19, Part A shows greenhouse gas (GHG) emission rates for associated equipment used during natural gas well production operations. Table GHG-1 was adapted from an analysis of potential impacts to air performed in 2009 by ICF International under contract to NYSERDA. GHG emission rates for flaring during the completion phase were also obtained from the ICF International study. The emission factors in the table are typically listed in units of pounds emitted per hour for each piece of equipment or are based on gas throughput. The emissions rates specified in the table were used to determine the annual emissions in tons for each stationary source, except for engines used for rig and hydraulic fracturing engines, using the below equation. The *Activity Factor* represents the number of pieces of equipment or occurrences.

$$\text{Emissions (tons/yr.)} = \text{Emissions Factor (lbs./hr)} \times \text{Duration (yr.)} \times (8{,}760 \text{ hrs/yr.}) \times (1 \text{ US short ton}/2{,}000 \text{ lbs}) \times \text{Activity Factor}$$

A material balance approach based on fuel usage and fuel carbon analysis, assuming complete combustion (i.e., 100% of the fuel carbon combusts to form CO_2), is the preferred technique for estimating CO_2 emissions from stationary combustion engines.[121] This approach was used for the engines required for conducting drilling and hydraulic fracturing operations. Actual fuel usage, such as the volume of fuel needed to perform hydraulic fracturing, was used where available to determine CO_2 emissions. For emission sources where actual fuel usage data was not available, estimates were made based on the type and use of the engines needed to perform the work. For GHG emission from mobile sources, such as trucks used to transport equipment and materials, where fuel use data was not available VMT was used to estimate fuel usage. The calculated fuel used was then used to determine estimated CO_2 emissions from the mobile

[121] API, 2004; amended 2005., p. 4-3.

sources. A sample calculation showing this methodology for determining combustion emissions (CO_2) from mobile sources is included as Appendix 19, Part B.

Carbon dioxide and CH_4 emissions, the focus of this analysis, are produced from the flaring of natural gas during the well completion phase. Emission rates and calculations from the flaring of natural gas are presented in the previously mentioned 2009 ICF International report. In that report, it was determined that approximately 576 tons of CO_2 and 4.1 tons of CH_4 are emitted each day for a well being flared at a rate of 10 MMcf/d. ICF International's calculations assumed that 2% of the gas by volume goes uncombusted. ICF International relied on an average composition of Marcellus Shale gas to perform its emissions calculations.

6.6.5 Drilling Rig Mobilization, Site Preparation and Demobilization

Transportation combustion sources are the engines that provide motive power for vehicles used as part of wellsite operations. Transportation sources may include vehicles such as cars and trucks used for work-related personnel transport, as well as tanker trucks and flatbed trucks used to haul equipment and supplies. Light-duty and heavy-duty vehicles use is accounted for and differentiated in this analysis.[122] The fossil fuel-fired internal combustion engines used in transportation are a significant source of CO_2 emissions. Small quantities of CH_4 and N_2O are also emitted based on fuel composition, combustion conditions, and post-combustion control technology. Estimating emissions from mobile sources is complex, requiring detailed information on the types of mobile sources, fuel types, vehicle fleet age, maintenance procedures, operating conditions and frequency, emissions controls, and fuel consumption. The EPA has developed a software model, MOBILE Vehicle Emissions Modeling Software, that accounts for these factors in calculating exhaust emissions (CO_2, HC, CO, NO_x, particulate matter, and toxics) for gasoline and diesel fueled vehicles. The preferred approach for estimating CH_4 and N_2O emissions from mobile sources is to assume that these emissions are negligible compared to CO_2.[123]

An alternative to using modeling software for determining CO_2 emissions for general characterization is to estimate GHG emissions using VMT, which includes a determination of

[122] ALL Consulting, 2011, Exhibits 19B, 20B.

[123] API, 2004; amended 2005, pp. 4-32, 4-33.

estimated fuel usage, or use a fuel usage estimate if available. These methodologies were used to calculate the tons of CO_2 emissions from mobile sources related to the subject activity. A sample CO_2 emissions calculation using fuel consumption is shown in Appendix 19, Part B. Table GHG-2 in Appendix 19, Part A includes CO_2 emission estimates for transporting the equipment necessary for constructing the access road and well pad, and moving the drilling rig to and from the well site. For horizontal wells, Table GHG-2 assumes that the same rig stays on location and drills both the vertical and lateral portions of a well.

As previously mentioned, because all activities are assumed to be performed sequentially requiring a single rig move, the GHG emissions presented in Table GHG-2 are representative of either a one-well project or four-well pad. As shown in the table, approximately 15 tons of CO_2 emissions are expected from a mobilization of the drilling rig, including site preparation. Site preparation for a single vertical well would be less due to a smaller pad size but for simplification site preparation is assumed the same for all well scenarios considered. The calculated CO_2 emissions shown in this table and all other tables included in this analysis have been rounded up to the next whole number.

6.6.6 Completion Rig Mobilization and Demobilization

Table GHG-3 in Appendix 19, Part A includes CO_2 emission estimates for transporting the completion rig to and from the wellsite. As shown in the table, approximately 4 tons of CO_2 emissions may be generated from a mobilization of the completion rig. For simplification, tramsportation associated with rig mobilization for the completion rig was assumed to be the same as that for the drilling rig. It is acknowledged that this assumption is conservative.

6.6.7 Well Drilling

Vertical wells may be drilled entirely using compressed air as the drilling fluid or possibly with air for a portion of the well and mud in the target interval. For horizontal wells, drilling activities would typically include the drilling of the vertical and lateral portions of a well using compressed air and mud (or other fluid) respectively. Regardless of the type of well, drilling activities are dependent on the internal combustion engines needed to supply electrical or hydraulic power to: 1) the rotary table or topdrive that turns the drillstring, 2) the drawworks, 3) air compressors, and 4) mud pumps. Carbon dioxide emissions occur from the engines needed to

perform the work required to spud the well and reach its total depth. Table GHG-4 in Appendix 19, Part A includes estimates for CO_2 emissions generated by these stationary sources. As shown in the table, approximately 83 tons of CO_2 emissions per single vertical well would be generated as a result of drilling operations. Tables GHG-5 and GHG-6 show CO_2 emissions of 194 tons and 776 tons for the drilling of a single horizontal well and four-well pad, respectively.

6.6.8 Well Completion

Well completion activities include 1) transport of required equipment and materials to and from the site, 2) hydraulic fracturing of the well, 3) a flowback period, including flaring, to clean the well of fracturing fluid and excess sand used as the hydraulic fracturing proppant, 4) drilling out of hydraulic fracturing stage plugs and the running of production tubing by the completion rig and 5) site reclamation. Mobile and stationary engines, and equipment used during the aforementioned completion activities emit CO_2 and/or CH_4. Tables GHG-7, GHG-8 and GHG-9 in Appendix 19, Part A include estimates of individual and total emissions of CO_2 and CH_4 generated during the completion phase for a single vertical well, single horizontal well and a four-well pad, respectively.

Similar to the above discussion regarding mobilization and demobilization of rigs, transport of equipment and materials, which results in CO_2 emissions, is necessary for completion of wells. The results of this evaluation are shown in Tables GHG-7, GHG-8 and GHG-9 of Appendix 19, Part A. GHG emissions of CO_2 from transportation provided in the tables rely on estimated fuel usage for both light and heavy trucks. A sample calculation for determining CO_2 emissions based on fuel usage is shown in Appendix 19, Part B. As shown in Table GHG-7, transportation related completion-phase emissions of CO_2 for a single vertical well is estimated at 12 tons. For the single horizontal well and the four-well pad (see Table GHG-8 and GHG-9), transportation related completion-phase CO_2 emissions are estimated at 31 to 115 tons, respectively.

Hydraulic fracturing operations require the use of many engines needed to drive the high-pressure high-volume pumps used for hydraulic fracturing (see multiple “Pump trucks” in the Photos Section of Chapter 6). As previously discussed and shown in Table GHG-5 in Appendix 19, Part A, an average (i.e., 29,000 gallons of diesel) of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring

Pennsylvania and West Virginia was used to calculate the estimated amount of CO_2 emitted during hydraulic fracturing. Fuel usage for the single vertical well was prorated to account for less time pumping (i.e., one-eighth). Tables GHG-7, GHG-8 and GHG-9 show that approximately 54 tons and 325 tons of CO_2 emissions per well would be generated as a result of single vertical well and single horizontal well hydraulic fracturing operations, respectively.

Subsequent to hydraulic fracturing in which fluids are pumped into the well, the direction of flow is reversed and flowback waters, including reservoir gas, are routed through separation equipment to remove excess sand, then through a line heater and finally through a separator to separate water and gas on route to the flare stack. Generally speaking, flares in the oil and gas industry are used to manage the disposal of hydrocarbons from routine operations, upsets, or emergencies via combustion.[124] However, only controlled combustion events would be flared through stacks used during the completion phase for the Marcellus Shale and other low-permeability gas reservoirs. A flaring period of 3 days was considered for this analysis for the vertical and horizontal wells respectively although the actual period could be either shorter or longer.

Initially, only a small amount of gas recovered from the well is vented for a relatively short period of time. If a sales line is available, once the flow rate of gas is sufficient to sustain combustion in a flare, the gas is flared until there is sufficient flowing pressure to flow the gas into the sales line.[125] Otherwise, the gas is flared and combusted at the flare stack. As shown in Tables GHG-7 and GHG-8 in Appendix 19, Part A, approximately 1,728 tons of CO_2 and 12 tons of CH_4 emissions are generated per well during a three-day flaring operation for a 10 Mmcf/d flowrate. As mentioned above, the actual duration of flaring may be more or less. The CH_4 emissions during flaring result from 2% of the gas flow remaining uncombusted. ICF computed the primary CO_2 and CH_4 emissions rates using an average Marcellus gas composition.[126] The duration of flaring operations may be shortened by using specialized gas recovery equipment, provided a gas sales line is in place at the time of commencing flowback from the well. Recovering the gas to a sales line, instead of flaring it, is called a REC and is

[124] API, 2004; amended 2005. p. 4-27.

[125] ALL Consulting, 2009. p. 14.

[126] ICF Task 2, 2009, p. 28.

further discussed in Chapter 7 as a possible mitigation measure, and in Appendix 25 (REC Executive Summary included by ICF for its work in support of preparation of the SGEIS).

The final work conducted during the completion phase consists of using a completion rig, possibly a coiled-tubing unit, to drill out the hydraulic fracturing stage plugs and run the production tubing in the well. Assuming a fuel consumption rate of 25 gallons per hour and an operating period of 24 hours, the rig engines needed to perform this work emit CO_2 at a rate of approximately 4 tons per single vertical well and 7 tons per single horizontal well. No stage plug milling is normally required and less tubing is run for a single vertical well as compared to a horizontal well, and less completion time results in less GHG emissions. After the completion rig is removed from the site, earth moving equipment would be transported to the site and the area would be reworked and graded, which adds another 9 tons of CO_2 emissions for either a one-well project or four-well pad. Tables GHG-7, GHG-8 and GHG-9 in Appendix 19, Part A show CO_2 emissions from these final stages of work during the well completion phase for a single vertical well, single horizontal well and a four-well pad, respectively. Site work for a single vertical well would be less due to a smaller pad size but for simplification, site work is assumed the same for all well scenarios considered.

6.6.9 Well Production

GHGs from the well production phase include emissions from transporting the production equipment to the site and then operating the equipment necessary to process and flow the natural gas from the well into the sales line. Carbon dioxide emissions are generated from the trucks needed to haul the production equipment to the wellsite. As previously stated, GHG emissions of CO_2 from transportation rely on estimated fuel usage where available or VMT, which ultimately requires a determination of fuel usage. Such emissions associated with well production activities, include those from transportation related to the removal of production brine, as discussed below. The estimated VMT for each case was then used to determine approximate fuel use and resultant CO_2 emissions. As shown in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A, transportation needed to haul production equipment to a wellsite for a one-well project and a four-well pad results in first-year CO_2emissions of approximately 3 tons and 11 tons, respectively.

Well production may require the removal of production brine from the site which, if present, is stored temporarily in plastic, fiberglass or steel brine production tanks, and then transported off-site for proper disposal or reuse. The trucks used to haul the production brine off-site generate CO_2 emissions. Transportation estimates were used to determine CO_2 emissions from each well development scenario, and emission estimates are presented in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A. Table GHG-10 presents CO_2 and CH_4 emissions for a one-well project for the period of production remaining in the first year after the single vertical well is drilled and completed. For the purpose of this analysis, the duration of production for a single vertical well in its first year was estimated at 349 days (i.e., 365 days minus 16 days to drill & complete) and for a single horizontal well in its first year 331 days (i.e., 365 days minus 34 days to drill & complete). Table GHG-13 shows estimated annual emissions for a single vertical well or single horizontal well commencing in year two, and producing for a full year. Table GHG-12 presents CO_2 and CH_4 emissions for a four-well pad for the period of production remaining in the first year after all ten wells are drilled and completed. For the purpose of this analysis, the duration of production for the ten-well pad in its first year was estimated at 229 days (i.e., 365 days minus 136 days to drill & complete). Instead of work phases occurring sequentially, actual operations may include concurrent well drilling and producing activities on the same well pad. Table GHG-14 shows estimated annual emissions for a four-well project commencing in year two, and producing for a full year.

GHGs in the form of CO_2 and CH_4 are emitted during the well production phase from process equipment and compressor engines. Glycol dehydrators, specifically their vents, which are used to remove moisture from the natural gas in order to meet pipeline specifications and dehydrator pumps, generate vented CH_4 emissions, as do pneumatic device vents which operate by using gas pressure. Compressors used to increase the pressure of the natural gas so that the gas can be put into the sales line typically are driven by engines which combust natural gas. The compressor engine's internal combustion cycle results in CO_2 emissions while compression of the natural gas generates CH_4 fugitive emissions from leaking packing systems. All packing systems leak under normal conditions, the amount of which depends on cylinder pressure, fitting and alignment of the packing parts, and the amount of wear on the rings and rod shaft.[127] The emission rates

[127] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

presented in Table GHG-1, Appendix 19, Part A "Emission Rates for Well Pad" were used to calculate estimated emissions of CO_2 and CH_4 for each stationary source for a single vertical well, single horizontal well and four-well pad using the equation noted in Section 6.6.4 and the corresponding Activity Factors shown in Tables GHG-10, GHG-11, GHG-12, GHG-13 and GHG-14 in Appendix 19, Part A. Based on the specified emissions rates for each piece of production equipment, the calculated annual GHG emissions presented in the Tables show that the compressors, glycol dehydrator pumps and vents contribute the greatest amount of CH_4 emissions during the this phase, while operation of pneumatic device vents also generates vented CH_4 emissions. The amount of CH_4 vented in the compressor exhaust was not quantified in this analysis but, according to Volume II: Compressor Driver Exhaust, of the 1996 Final Report on Methane Emissions from the Natural Gas Industry, compressor exhaust accounts for "about 7.9% of methane emissions from the natural gas industry."

6.6.10 Summary of GHG Emissions

As previously discussed, wellsite operations were divided into the following five phases to facilitate GHG analysis: 1) Drilling Rig Mobilization, Site Preparation and Demobilization, 2) Completion Rig Mobilization and Demobilization, 3) Well Drilling, 4) Well Completion (includes hydraulic fracturing and flowback) and 5) Well Production. Each of these phases was analyzed for potential GHG emissions, with a focus on CO_2 and CH_4 emissions. The results of these phase-specific analyses for a single vertical well, single horizontal well and four-well pad are detailed in Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part A. In addition, the tables include estimates of GHG emissions occurring in the first year and each producing year thereafter for each project type.

The goal of this review is to characterize and present an estimate of total annual emissions of CO_2, and other relative GHGs, as both short tons and CO_2e expressed in short tons for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. To determine CO_2e, each greenhouse gas has been assigned a number or factor that reflects its global warming potential (GWP). The GWP is a measure of a compound's ability to trap heat over a certain lifetime in the atmosphere, relative to the effects of the same mass of CO_2 released over the same time period. Emissions expressed in equivalent terms highlight the contribution of the various gases to the overall inventory.

Therefore, GWP is a useful statistical weighting tool for comparing the heat trapping potential of various gases.[128] For example, Chesapeake Energy Corporation's July 2009 Fact Sheet on greenhouse gas emissions states that CO_2 has a GWP of 1 and CH_4 has a GWP of 23, and that this comparison allows emissions of greenhouse gases to be estimated and reported on an equal basis as CO_2e.[129] However, GWP factors are continually being updated, and for the purpose of this analysis as required by the Department's 2009 *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*, the 100-Year GWP factors provided in below Table 6.27 were used to determine total GHGs as CO_2e. Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part A include a summary of estimated CO_2 and CH_4 emissions from the various operational phases as both short tons and as CO_2e expressed in short tons.

Table 6.27 - Global Warming Potential for Given Time Horizon[130]

Common Name	Chemical Formula	20-Year GWP	100-Year GWP	500-Year GWP
Carbon dioxide	CO_2	1	1	1
Methane	CH_4	72	25	7.6

Table 6.28 is a summary of total estimated CO_2 and CH_4 emissions for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing, as both short tons and as CO_2e expressed in short tons. The below table includes emission estimates for the first full year in which drilling is commenced and subsequent producing years for each project type (i.e., single vertical well, single horizontal well and four-well pad), sourcing of equipment and materials.

The noted CH_4 emissions occurring during the production process and compression cycle represent ongoing annual GHG emissions. As noted above, for the purpose of assessing GHG impacts, each ton of CH_4 emitted is equivalent to 25 tons of CO_2. Thus, because of its recurring nature, the importance of limiting CH_4 emissions throughout the production phase cannot be overstated.

[128] API, August 2009. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

[129] Chesapeake Energy Corp., July 2009. *Greenhouse Gas Emissions and Reductions* Fact Sheet.

[130] Adapted from Forster, et al. 2007, Table 2.14. Chapter 2, p. 212. http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf.

Table 6.28 - Summary of Estimated Greenhouse Gas Emissions (Revised July 2011)

	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[131]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Estimated First-Year Green House Gas Emissions from Single Vertical Well	8,660	246	6,150	14,810
Estimated First-Year Green House Gas Emissions from Single Horizontal Well	8,761	240	6,000	14,761
Estimated First-Year Green House Gas Emissions from Four-Well Pad	13,901	402	10,050	23,951
Estimated Post First-Year Annual Green House Gas Emissions from Single Vertical or Single Horizontal Well	6,164	244	6,100	12,264
Estimated Post First-Year Annual Green House Gas Emissions from Four-Well Project	6,183	565	14,125	20,300

[131] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Some uncertainties remain with respect to quantifying GHG emissions for the subject activity. For the potential associated GHG emission sources, there are multiple options for determining the emissions, often with different accuracies. Table 6.29, which was prepared by the API, illustrates the range of available options for estimating GHG emissions and associated considerations. The two types of approaches used in this analysis were the "Published emission factors" and "Engineering calculations" options. These approaches, as performed, rely heavily on a generic set of assumptions with respect to duration and sequencing of activities, and size, number and type of equipment for operations that would be conducted by many different companies under varying conditions. Uncertainties associated with GHG emission determinations can be the result of three main processes noted below.[132]

- Incomplete, unclear or faulty definitions of emission sources;
- Natural variability of the process that produces the emissions; and
- Models, or equations, used to quantify emissions for the process or quantity under consideration.

Nevertheless, while the results of potential GHG emissions presented in above Table 6.15 may not be precise for each and every well drilled, the real benefit of the emission estimates comes from the identification of likely major sources of CO_2 and CH_4 emissions relative to the activities associated with gas exploration and development. It is through this identification and understanding of key contributors of GHGs that possible mitigation measures and future efforts can be focused in New York. Following, in Chapter 7, is a discussion of possible mitigation measures geared toward reducing GHGs that would be required, with emphasis on CH_4.

[132] API, August 2009, p. 3-30. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

Table 6.29 - Emission Estimation Approaches – General Considerations[133]

Types of Approaches	General Considerations
Published emission factors	· Accounts for average operations or conditions · Simple to apply · Requires understanding and proper application of measurement units and underlying standard conditions · Accuracy depends on the representativeness of the factor relative to the actual emission source · Accuracy can vary by GHG constituents (i.e., CO_2, CH_4, and N_2O)
Equipment manufacturer emission factors	· Tailored to equipment-specific parameters · Accuracy depends on the representativeness of testing conditions relative to actual operating practices and conditions · Accuracy depends on adhering to manufacturers inspection, maintenance and calibration procedures · Accuracy depends on adjustment to actual fuel composition used on-site · Addition of after-market equipment/controls will alter manufacturer emission factors
Engineering calculations	· Accuracy depends on simplifying assumptions that may be contained within the calculation methods · May require detailed data
Process simulation or other computer modeling	· Accuracy depends on simplifying assumptions that may be contained within the computer model methods · May require detailed input data to properly characterize process conditions · May not be representative of emissions that are due to operations outside the range of simulated conditions
Monitoring over a range of conditions and deriving emission factors	· Accuracy depends on representativeness of operating and ambient conditions monitored relative to actual emission sources · Care should be taken when correcting to represent the applicable standard conditions · Equipment, operating, and maintenance costs must be considered for monitoring equipment
Periodic or continuous[a] monitoring of emissions or parameters[b] for calculating emissions	· Accounts for operational and source specific conditions · Can provide high reliability if monitoring frequency is compatible with the temporal variation of the activity parameters · Instrumentation not available for all GHGs or applicable to all sources · Equipment, operating, and maintenance costs must be considered for monitoring equipment
Footnotes and Sources: [a] Continuous emissions monitoring applies broadly to most types of air emissions, but may not be directly applicable nor highly reliable for GHG emissions. [b] Parameter monitoring may be conducted in lieu of emissions monitoring to indicate whether a source is operating properly. Examples of parameters that may be monitored include temperature, pressure and load.	

[133] API August 2009, p. 3-9, http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

6.7 Naturally Occurring Radioactive Materials in the Marcellus Shale

Chapter 4 explains that the Marcellus Shale is known to contain NORM concentrations at higher levels than surrounding rock formations, and Chapter 5 provides some sample data from Marcellus Shale cuttings. Activities that have the potential to concentrate these constituents through surface handling and disposal may need regulatory oversight to ensure adequate protection of workers, the general public, and the environment. Gas wells can bring NORM to the surface in the cuttings, flowback fluid and production brine, and NORM can accumulate in pipes and tanks (pipe scale and sludge.) Based upon currently available information it is anticipated that flowback water will not contain levels of NORM of significance, whereas production brine is known to contain elevated NORM levels. Radium-226 is the primary radionuclide of concern from the Marcellus.

Elevated levels of NORM in production brine (measured in picocuries/liter or pCi/L) may result in the buildup of pipe scale containing elevated levels of radium (measured in pCi/g). The amount and concentration of radium in the pipe scale would depend on many conditions, including pressures and temperatures of operation, amount of available radium in the formation, chemical properties, etc. Because the concentration of radium in the pipe scale cannot be measured without removing or disconnecting the pipe, a surrogate method is employed, conducting a radiation survey of the pipe exterior. A high concentration of radium in the scale would result in an elevated radiation exposure level at the pipe's exterior surface (measured in mR/hr) and can be detected with a commonly used survey instrument. The Department of Health would require a radioactive materials license when the radiation exposure levels of accessible piping and equipment are greater than 50 microR/hr (µR/hr). Equipment that exhibits dose rates in excess of this level will be considered to contain processed and concentrated NORM for the purpose of waste determinations.

Oil and gas NORM occurs in both liquid (production brine), solid (pipe scale, cuttings, tank and pit sludges), and gaseous states (produced gas). Although the highest concentrations of NORM are in production brine, it does not present a risk to workers because the external radiation levels are very low. However, the build-up of NORM in pipes and equipment (pipe scale and sludge) has the potential to expose workers handling (cleaning or maintenance) the pipe to increased radiation levels. Also wastes from the treatment of production brines may contain concentrated

NORM and therefore may require controls to limit radiation exposure to workers handling this material as well as to ensure that this material is disposed of in accordance with 6 NYCRR § 380.4.

Radium is the most significant radionuclide contributing to oil and gas NORM. It is fairly soluble in saline water and has a long radioactive half life - about 1,600 years (Table 6.30). Radon gas, which under most circumstances is the main human health concern from NORM, is produced by the decay of radium-226, which occurs in the uranium-238 decay chain. Uranium and thorium, which are naturally occurring parent materials for radium, are contained in mineral phases in the reservoir rock cuttings, but have very low solubility. The very low concentrations and poor water solubility are such that uranium and thorium pose little potential health threat.

Table 6.30 - Radionuclide Half-Lives

Radionuclide	Half-life	Mode of Decay
Ra-226	1,600 years	alpha
Rn-222	3.824 days	alpha
Pb-210	22.30 years	beta
Po-210	138.40 days	alpha
Ra-228	5.75 years	beta
Th-228	1.92 years	alpha
Ra-224	3.66 days	alpha

In addition to exploration and production (E&P) worker protection from NORM exposure, the disposal of NORM-contaminated E&P wastes is a major component of the oil and gas NORM issue. This has attracted considerable attention because of the large volumes of production brine (>109 billion bbl/yr; API estimate) and the high costs and regulatory burden of the main disposal options, which are underground injection in Class II UIC wells and offsite treatment. The Environmental Sciences Division of Argonne National Laboratory has addressed E&P NORM disposal options in detail and maintains a Drilling Waste Management Information System

website that links to regulatory agencies in all oil and gas producing states, as well as providing detailed technical information.

In NYS the disposal of processed and concentrated NORM in the form of pipe scale or water treatment waste is subject to regulation under Part 380. Because disposal of Part 380 regulated waste is prohibited in Part 360 regulated solid waste landfills, this waste would require disposal in out-of-state facilities approved to accept NORM wastes. Disposal facilities that can accept this type of waste include select RCRA C facilities and low-level radioactive waste disposal sites.

6.8 Socioeconomic Impacts[134]

This section provides a discussion of the potential socioeconomic impacts on the Economy, Employment, and Income (Section 6.8.1); Population (Section 6.8.2); Housing (Section 6.8.3); Government Revenues and Expenditures (Section 6.8.4); and Environmental Justice (Section 6.8.5). A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this SGEIS.

To estimate the socioeconomic impacts associated with the use of high-volume hydraulic fracturing techniques for extracting natural gas, several assumptions must be made about the amount of natural gas development that would occur, the expected rate of development, the length of time over which that development would occur, and the distribution of this development throughout the state.

For the purposes of this SGEIS, the expected rate of development is measured by the number of wells constructed annually. Two different levels of development are analyzed – a low development scenario, and an average development scenario. These development scenarios were developed by the Department based on information the Department had requested from the Independent Oil & Gas Association of New York (IOGA-NY). IOGA-NY started with an estimated average rate of development based on the following assumptions:

[134] Section 6.8, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

- Approximately 67% of the area covered by the Marcellus and Utica shale is developable;
- Approximately 90% of wells would be horizontal wells, with an average of 160 acres/well; and
- Approximately 10% of wells would be vertical wells, with an average of 40 acres/well.

For the low rate of development, DEC assumed a rate of 25% of IOGA-NY's estimated average rate of development.

Table 6.31 provides a highlight of the major assumptions for each of these scenarios. In both scenarios, the maximum build-out of new wells is assumed to be completed in Year 30. Under the low development scenario, a total of 9,461 horizontal wells and 1,071 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). Under the average development scenario a total of 37,842 horizontal wells and 4,284 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). The high development scenario, which is analyzed in the Economic Assessment Report, assumes a total of 56,508 horizontal and 6,273 vertical wells are constructed at maximum build-out (e.g., Year 30).

Analysis of the high development scenario is not included in this socioeconomic section of the SGEIS in order to be conservative in assessing the positive potential economic benefits of high-volume hydraulic fracturing in New York State. The high development scenario was used as the conservative assumption of activity for all other sections of this SGEIS.

Economic realities, including diminishing marginal returns associated with drilling wells further from the fairway in less than ideal locations, and the exclusion of high-volume hydraulic fracturing wells from certain sensitive locations, would make it highly unlikely that the maximum build-out under the high development scenario would occur. Therefore, only the low and average development scenarios are discussed throughout this section.

These development scenarios are designed to provide order-of-magnitude estimates for the following socioeconomic analysis and are in no way meant to forecast actual well development levels in the Marcellus and Utica Shale reserves in New York State. These scenarios should be

viewed as a "best estimate" of the range of possible amounts of development that could occur in New York State.

Table 6.31 - Major Development Scenario Assumptions (New August 2011)

	Scenarios	
	Low	**Average**
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	9,461	37,842
Vertical	1,071	4,284
Total	**10,532**	**42,126**
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	371	1,484
Vertical	42	168
Total	**413**	**1,652**

Both development scenarios assume a consistent timeline for development and production. Development is assumed to occur for a period of 30 years, starting with a 10-year "ramp-up" period. The number of new wells constructed each year is assumed to reach the maximum in Year 10 and to continue at this level until Year 30, when all new well construction is assumed to end. This assumption, which does not significantly affect the socioeconomic impact analysis, was used to remain consistent with other sections of the SGEIS. In actuality, well development would more likely gradually ramp up, reach a peak, and then gradually ramp down as fewer and fewer wells were completed. However, this curve would not necessarily be smooth.

It is unlikely that new well construction would occur under a steady, constant rate. Economic factors such as the price of natural gas, input costs, the price of other energy sources, changes in technology, and the general economic conditions of the state and nation would all affect the yearly rate of well construction and the overall level of development of the gas reserves. The actual track of well construction would likely be much more cyclical in nature than as described in the following sections.

The average development scenario should be viewed as the upper boundary of possible development, while the low development scenario should be viewed as the likely lower boundary of possible development. As shown in Table 6.31, the maximum number of new wells

developed in a year under the low development scenario is 371 horizontal and 42 vertical wells, and the maximum number of new wells developed in a year under the average development scenario is 1,484 horizontal and 168 vertical wells.

Each newly constructed well is assumed to have an average productive life of 30 years. For example, wells constructed in Year 1 are assumed to still be producing in Year 30, and wells constructed in Year 10 are assumed to produce until Year 40. Because of the assumption of a 30-year development period, wells constructed in Year 30 are assumed to be productive until Year 60. Assuming a 30-year development period and a 30-year production life for each well, the number of productive wells in New York State would be expected to grow until Year 30, at which point, the number of productive wells would peak. After Year 30, with no new wells being constructed, the number of wells in production would begin to decline. Because the number of annual wells approved and developed each year is different for the two development scenarios, the peak number of operating wells at Year 30 also differs for each scenario.

Under both development scenarios, natural gas production in New York State would occur from Year 1 until Year 60, with Year 30 having the maximum number of wells in production. After Year 30, producing wells would gradually decline until Year 60, at which time it is assumed that production stops.

As discussed in Section 2.4.13, no site-specific project locations are being evaluated in the SGEIS. Therefore, for purposes of analysis, three distinct regions were identified within the area where potential drilling may occur in order to take a closer look at the potential impacts at the regional and local levels. The three regions were selected to evaluate differences between areas with a high, moderate, and low production potential; areas that have experienced gas development in the past and areas that have not experienced gas development in the past; and differences in land use patterns. The three representative regions and the respective counties within the region are:

- Region A: Broome County, Chemung County, and Tioga County;
- Region B: Delaware County, Otsego County; and Sullivan County; and
- Region C: Cattaraugus County and Chautauqua County

This analysis is not intended to imply that impacts would occur only in these three regions. Impacts would occur at the local and regional levels wherever high-volume hydraulic fracturing wells are constructed. The actual locations of these wells have not yet been determined, and they could be constructed wherever there is low-permeable shale. Similar to the development scenarios described above, the representative regions are designed to give a range of possible socioeconomic impacts. Therefore, the results of the local and regional analysis should also be seen as order-of-magnitude estimates for the range of possible impacts. Further descriptions of the regions are provided in Section 2.4.11.

6.8.1 Economy, Employment, and Income

The following discusses the potential impacts on the economy, employment and income for New York State, and the local areas within each of the three regions (Regions A, B and C).

6.8.1.1 New York State

Economy and Employment

Development of low-permeability natural gas reservoirs in the Marcellus and Utica shale by high-volume hydraulic fracturing would be expected to have a significant, positive impact on the economy of New York State. Construction and operation of the new natural gas wells are expected to increase employment, earnings, and economic output throughout the state. According to statistics collected and calculations made by the Marcellus Shale Education and Training Center (the Center), in Pennsylvania, an average natural gas well using the high-volume hydraulic fracturing technique requires 410 individuals working in 150 different occupations. The manpower requirements to drill a single well were calculated to be 11.53 full-time equivalent (FTE) construction workers (Marcellus Shale Education and Training Center 2009).

A full-time equivalent worker is defined as one worker working eight hours a day for 260 days a year, or several workers working a total of 2,080 hours in a year. While the Center found that up to 410 individuals are required to build one well, only 11.53 FTE workers were needed. Typically, a high-volume hydraulic fracturing well is constructed over a 3- to 4-month period, and many of the individuals and occupations are needed for only a very short duration. Therefore, to accurately assess the economic impacts of constructing a high-volume hydraulic fracturing well, the FTE workforce was considered.

The Center also calculated the work force requirements for operating a well as 0.17 FTE workers, or approximately 354 person hours per year. In other words, approximately 1 FTE worker is required to operate and maintain every 6 wells in production (Marcellus Shale Employment and Training Center 2009). Unlike the construction workforce that drills the well within a few months and is finished, the operational workforce is required for the productive life of the well. For the purposes of this analysis, a 30-year productive life has been assumed for each well drilled. Therefore, for every new well drilled, 0.17 FTE workers are employed for 30 years.

In its study, the Marcellus Shale Employment and Training Center did not differentiate between the labor requirements needed to drill a horizontal versus a vertical well. Typically, it is much more costly and labor-intensive to drill a high-volume hydraulic fracturing horizontal well than it is to drill a high-volume hydraulic fracturing vertical well. Therefore, in an effort to be conservative and not overstate the positive economic impacts, a factor was applied to the 11.53 FTE figure for vertical wells in the estimates used for this analysis. This factor was calculated using the average depth of a vertical well compared to the average depth of a high-volume hydraulic-fracturing horizontal well. The resulting ratio of 0.2777 was applied to the 11.53 FTE labor requirement to estimate the overall labor requirements of a vertical well.

Using the workforce requirement figures developed by the Marcellus Shale Employment and Training Center and the two development scenarios described above, the expected impacts on employment and earnings from high-volume hydraulic fracturing were projected for New York State as a whole.

As shown in Table 6.32, annual direct construction employment is directly related to the number of wells drilled in a given year. At the maximum well construction rate assumed for each development scenario, total annual direct construction employment is predicted to range from 4,408 FTE workers under the low development scenario to 17,634 FTE workers under the average development scenario. These employment figures correspond to the annual construction of 413 horizontal and vertical wells under the low development scenario and 1,652 horizontal and vertical wells under the average development scenario. In order to reach the full build-out

potential used in the scenarios, it is assumed that construction employment and new well construction would remain at these levels for 20 years, starting in Year 10 (see Table 6.32).

The maximum direct production employment under each development scenario is also shown in Table 6.32. These figures represent the peak production year (Year 30), when the maximum build-out potential has been reached before any of the wells have stopped producing. The preceding and the following years all would have fewer production workers. At the peak, production employment would be expected to range from 1,790 FTE workers under the low development scenario to 7,161 FTE workers under the average development scenario (Table 6.32).

Table 6.32 - Maximum Direct and Indirect Employment Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Direct Employment Impacts		
Construction Employment[1]	4,408	17,634
Production Employment[2]	1,790	7,161
Indirect Employment [3]	7,293	29,174
Total Employment Impacts	13,491	53,969
Total Employment as a Percent of New York State 2010 Labor Force	0.2%	0.7%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

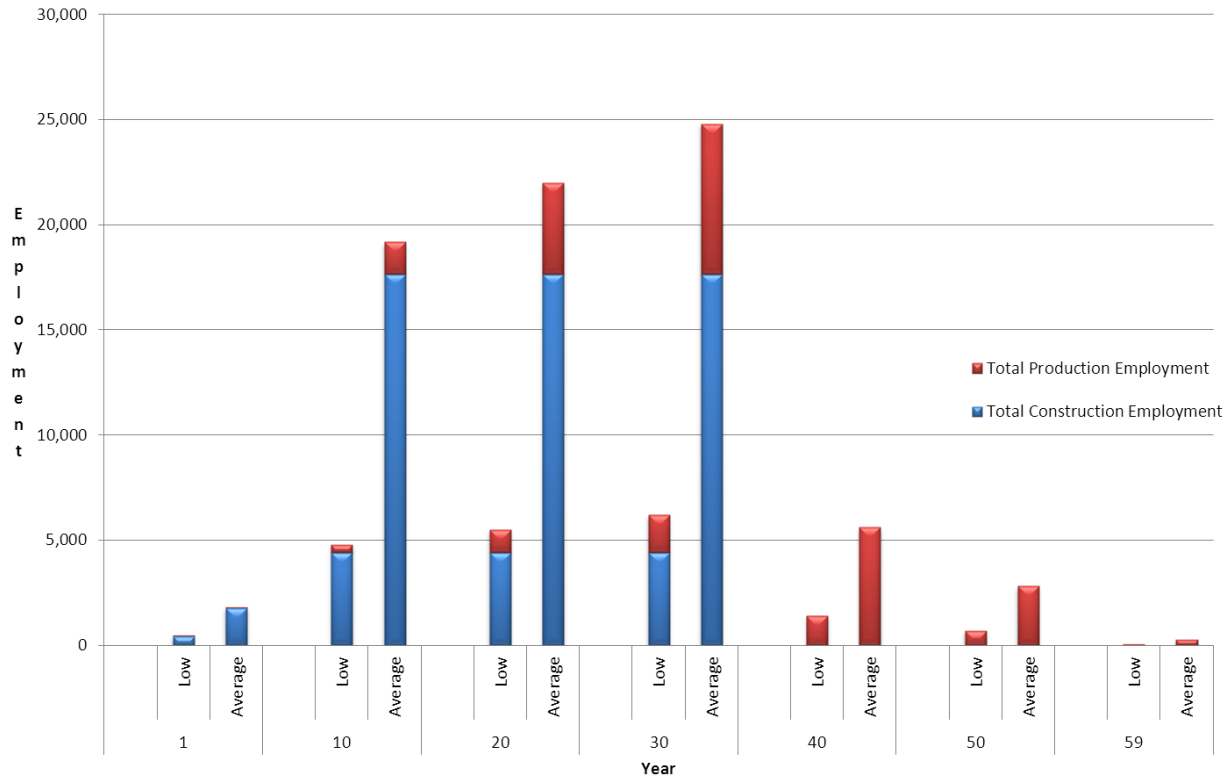
[1] These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

[2] These figures represent the maximum annual production employment under each scenario. These figures correspond to production employment in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected production employment for all other years.

[3] Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

Figure 6.12 illustrates the projected direct employment in New York State that would result from implementation of each development scenario over the 60-year time frame. The figure shows how construction and production employment levels are expected to vary, with peak direct employment occurring in Year 30.

Figure 6.12 – Projected Direct Employment in New York State Resulting from Each Development Scenario (New August 2011)

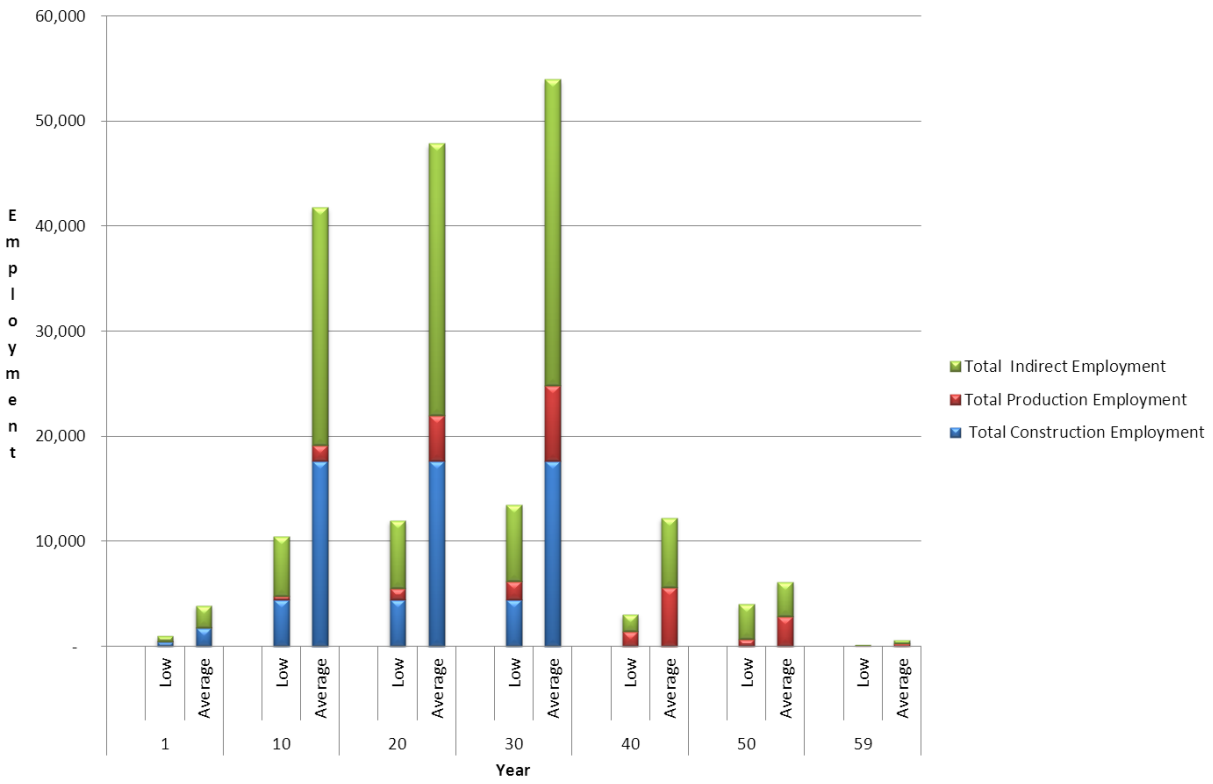


In addition to the direct employment impacts described above, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from suppliers in New York State, the overall demand for goods and services in the state would expand. Revenues at the wholesale and retail outlets and service providers within the state would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the state, thus "multiplying" the positive economic impacts of the original increase in construction/production spending. These "multiplier" effects would continue on until all of the original funds have left New York State's economy through either taxes or savings, or through purchases from outside the state.

Indirect employment impacts are expected to range from an additional 7,293 FTE workers under the low development scenario to an additional 29,174 FTE workers under the average development scenario. These annual figures represent the year with the maximum employment (Year 30). The years before and after this date would have less direct and indirect employment.

In total, at peak employment years, state approval of drilling in the Marcellus and Utica Shales is expected to generate between 13,491 and 53,969 direct and indirect jobs, which equates to 0.2% and 0.6%%, respectively, of New York State's 2010 total labor force, depending on the level and intensity of development that occurs (see Table 6.32). Figure 6.13 graphically illustrates the projected total employment in New York State that would result from each development scenario. As shown on the figure, total employment levels would be highest in Year 10 through Year 30. Once new well construction ends in Year 31, the direct and indirect employment would be greatly reduced.

Figure 6.13 - Projected Total Employment in New York State Resulting from Each Development Scenario (New August 2011)



The majority of these indirect jobs would be concentrated in the construction, professional, scientific, and technical services; real estate and rental/leasing; administrative and waste management services; management of companies and enterprises; and manufacturing industries.

Income

The increase in direct and indirect employment would have a positive impact on income levels in New York State. Table 6.33 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 through Year 30), total annual construction earnings are projected to range from $298.4 million under the low development scenario to nearly $1.2 billion under the average development scenario. Employee earnings from operational employment are expected to range from $121.2 million under the low development scenario to $484.8 million under the average development scenario in Year 30, the year that the maximum number of operational workers are assumed to be employed.

Table 6.33 - Maximum Direct and Indirect Annual Employee Earnings Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Direct Earnings Impacts		
Construction Earnings[1]	$298.4	$1,193.8
Production Earnings[2]	$121.2	$484.8
Indirect Employee Earnings Impacts[2,3]	$202.3	$809.2
Total Employee Earnings Impacts	$621.9	$2,487.8
Total Employee Earnings as a Percent of New York State's 2009 Total Wages	0.1%	0.5%

Source: U.S. Bureau of Economic Analysis 2011a; NYDOL 2009.

[1] These figures represent the maximum annual change in construction earnings under each scenario and correspond to construction earnings in Years 10 - 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction earnings for all other years.

[2] These figures represent the maximum annual production earnings and indirect employee earnings under each development scenario. These figures correspond to operations earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation earnings for all other years.

[3] Type I direct earnings multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

As described above, the construction and production activities would also generate significant indirect economic impacts. Indirect employee earnings are anticipated to range from $202.3 million under the low development scenario to $809.2 million under the average development scenario in Year 30. The total direct and indirect impacts on employee earnings are projected to range from $621.9 million to $2.5 billion per year at peak production and construction levels in Year 30. These figures equate to increases of between 0.1% and 0.5% of the total wages and salaries earned in New York State during 2009 (see Table 6.33).

Owners of the subsurface mineral rights where wells are drilled will also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or more of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas production is at its peak, can result in significant increases in income. Signing bonuses/bonus bids also can provide significant additional income to property owners.

6.8.1.2 Representative Regions

As noted above, three representative regions were selected to show the range of possible socioeconomic impacts that could occur at the local and regional levels. This analysis in no way is meant to imply that impacts will occur only in these three regions.

For purposes of this analysis, it is assumed that 50% of all new well construction would occur in Region A (Chemung, Tioga, and Broome counties); 23% would occur in Region B (Otsego, Delaware, and Sullivan counties); 5% would occur in Region C (Chautauqua and Cattaraugus counties); and the remaining 22% of new well construction would occur in the rest of New York State. Geological data on the extent and thickness of the low-permeability shale in New York State, including the Marcellus Shale and Utica Shale fairways, were the basis for these assumptions.

Table 6.34 details the major assumptions for each development scenario for each representative region. In all cases, total development is assumed to be reached at Year 30. As shown in the table, Region A is anticipated to receive the majority of the new well construction. The analysis of Region A is designed to show the upper bound of potential regional economic impacts. Under

the low development scenario, a total of 5,281 new wells would be constructed in the counties of Tioga, Chemung, and Broome. Under the average development scenario, a total of 21,067 new wells would be constructed in Region A. The projected maximum number of new wells developed per year in Region A would range from 207 to 826 wells, depending on the development scenario considered. The projected maximum number of new wells developed per year in Region B would range from 2,425 to 9,690 wells, depending on the development scenario (see Table 6.34).

In contrast, Region C is assumed to experience a much smaller level of well development than Region A or Region B. The analysis of Region C is designed to show the lower bound of potential regional economic impacts. Under the low development scenario, a total of 534 new wells would be constructed in Region C. Under the average development scenario, a total of 2,095 new wells would be constructed in Region C. The maximum number of new wells constructed each year in Region C is assumed to be 21 wells under the low development scenario and 82 wells under the average development scenario. The remaining 22% of the development would occur in the rest of the state (see Table 6.34).

Table 6.34 - Major Development Scenario Assumptions for Each Representative Region (New August 2011)

	Scenarios	
	Low	**Average**
Region A		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	4,743	18,923
Vertical	538	2,144
Total	5,281	21,067
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	186	742
Vertical	21	84
Total	207	826
Region B		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,170	8,697
Vertical	255	993
Total	2,425	9,690
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	85	341
Vertical	10	39

	Scenarios	
	Low	**Average**
Total	95	380
Region C		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	483	1,888
Vertical	51	207
Total	534	2,095
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	19	74
Vertical	2	8
Total	21	82
Rest of State		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,065	8,334
Vertical	227	940
Total	2,292	9,274
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	81	327
Vertical	9	37
Total	90	364

Economy and Employment

The proposed approval of the use of high-volume hydraulic fracturing technique would have a significant positive economic impact at the regional and local levels. Using the same methodology described above for the statewide analysis, the FTE labor requirements needed to construct and operate these wells were estimated for each region. Table 6.35 provides the maximum direct and indirect employment impacts that are predicted to occur under each development scenario for each region.

In Region A, which is used to define an upper boundary of the regional socioeconomic impacts, it is projected that direct construction employment would range from 2,204 FTE construction workers at the maximum employment levels under the low development scenario to 8,818 FTE construction workers at the maximum employment levels under the average development scenario. The new production employment in the region is expected to range from 895 to 3,581 FTE production workers per year.

In contrast, employment impacts are not anticipated to be as large in Region C, which is used to define a lower boundary for the regional socioeconomic impacts. At the maximum employment levels under the low development scenario, an estimated 221 new FTE constructions workers

and 90 new FTE production workers would be needed for drilling and maintaining the new natural gas wells. These figures would increase to 882 new FTE construction workers and 358 new FTE production workers under the average development scenario (see Table 6.35).

Table 6.35 - Maximum Direct and Indirect Employment Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Employment[1]	2,204	8,818
Production Employment[2]	895	3,581
Indirect Employment Impacts[3]	650	2,600
Total Employment Impacts	3,749	14,999
Total Employment as a Percentage of Region A's 2010 Total Labor Force	2.3%	9.3%
Region B		
Direct Employment Impacts		
Construction Employment[1]	1,014	4,056
Production Employment[2]	412	1,647
Indirect Employment Impacts[3]	191	762
Total Employment Impacts	1,617	6,465
Total Employment as a Percentage of Region B's 2010 Total Labor Force	1.8%	7.3%
Region C		
Direct Employment Impacts		
Construction Employment[1]	221	882
Production Employment[2]	90	358
Indirect Employment Impacts[3]	66	263
Total Employment Impacts	377	1,503
Total Employment as a Percentage of Region C's 2010 Total Labor Force	0.4%	1.4%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

[1] These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

[2] These figures represent the maximum annual production employment under each scenario. These figures correspond to production employment in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation employment for all other years.

[3] Separate Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II), were used for each region to estimate the indirect employment impacts.

Figure 6.14, Figure 6.15, and Figure 6.16 illustrate the projected direct employment in each representative region that would result from implementation of each development scenario over the 60-year time frame. The figures show how construction and production employment levels are expected to vary, with the peak direct employment occurring in Year 30.

Figure 6.14 - Projected Direct Employment in Region A Resulting from Each Development Scenario (New August 2011)

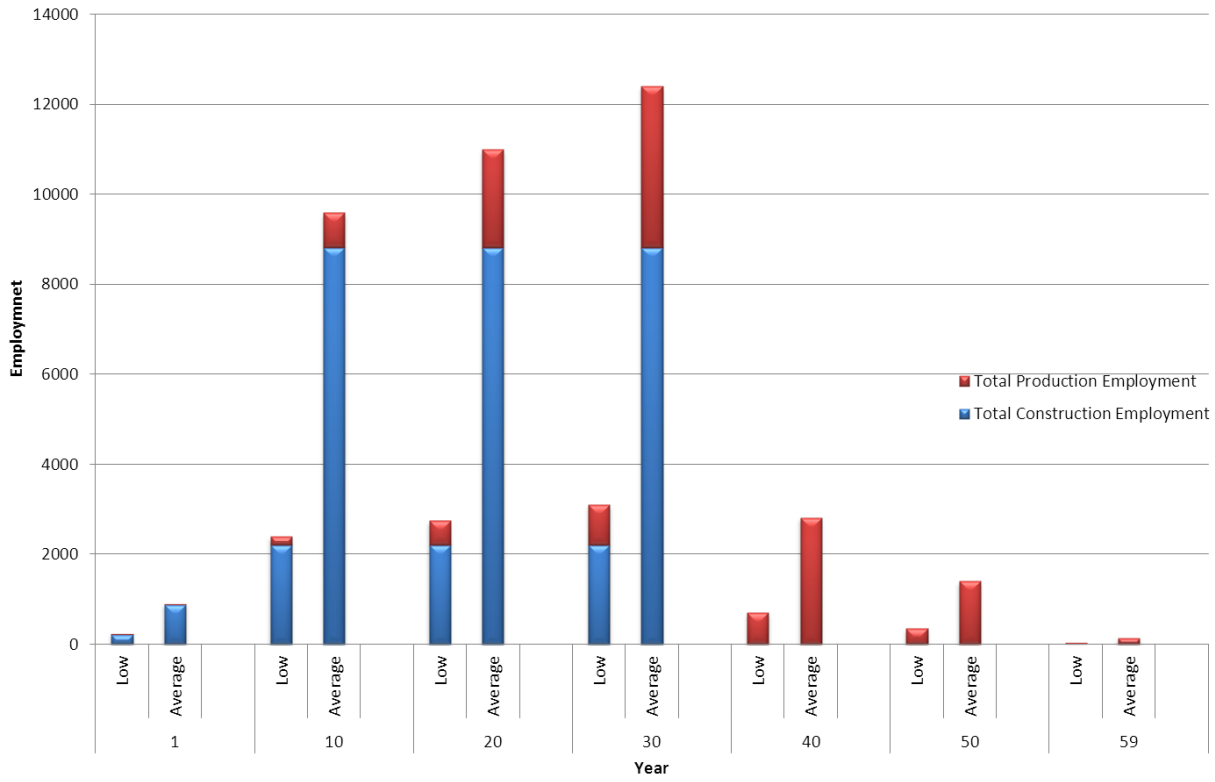


Figure 6.15 - Projected Direct Employment in Region B Resulting from Each Development Scenario (New August 2011)

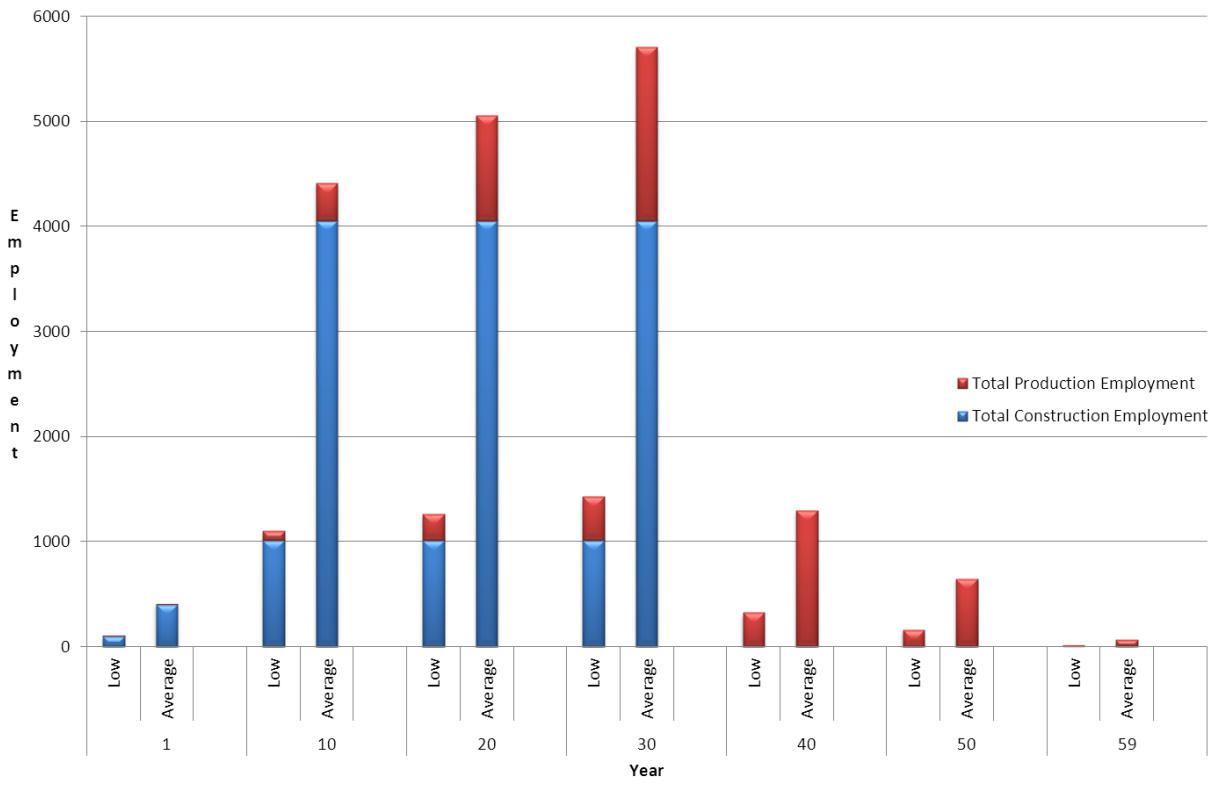
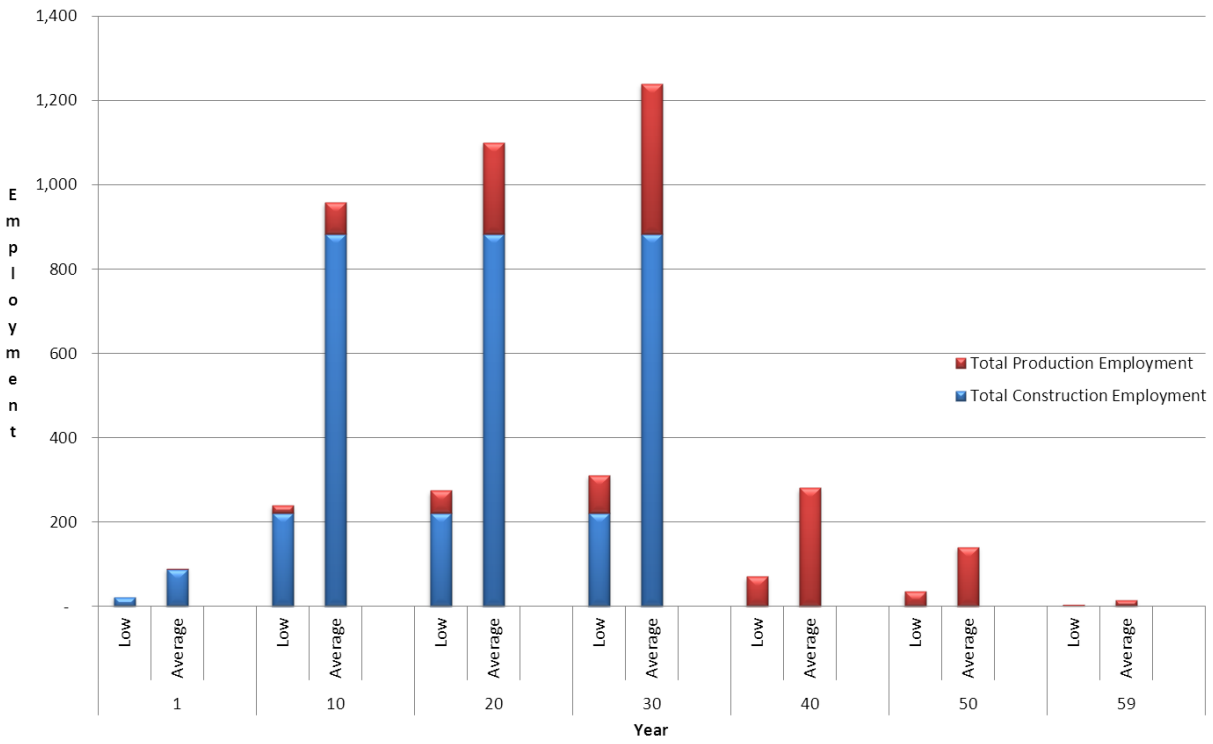


Figure 6.16 - Projected Direct Employment in Region C Resulting from Each Development Scenario (New August 2011)



As described previously for the statewide impacts, in addition to the direct employment impacts, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from regional suppliers, the overall demand for goods and services in the region would expand. Revenues at the region's wholesale and retail outlets and service providers would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the region, thus "multiplying" the positive economic impacts of the original increase in construction/operation spending. These "multiplier" effects would continue on until all of the original funds have left the region's economy through either taxes or savings, or through purchases from outside the region.

Indirect employment impacts are expected to range from a high of 650 to 2,600 indirect workers in Region A to a low of 66 to 263 indirect workers in Region C, depending on the development scenario. Direct employment multipliers of 1.4977 for Region A, 1.3272 for Region B, and 1.4657 for Region C for the oil and gas extraction industry were used in this analysis (U.S. Bureau of Economic Analysis 2011b; 2011c; 2011d). In contrast, New York State as a whole had a direct employment multiplier of 2.1766 for the oil and gas extraction industry (U.S. Bureau of Economic Analysis 2011a).

The employment and earnings multipliers in these regions are much smaller than in New York State as a whole, underscoring the fact that portions of these study areas do not have as well-developed, self-sufficient, and diverse economies as the state as a whole. In particular, the low multipliers reflect the fact that much of the goods and services that would be needed to construct and operate the new wells would be purchased outside the regions.

However, it can be expected that as the natural gas industry matures in these regions, more local suppliers and service providers would enter the markets and be able to respond to the natural gas industry's needs. As time goes by, a larger portion of the indirect economic impacts would remain in the region, further stimulating the local economies.

Figure 6.17, Figure 6.18, and Figure 6.19 graphically illustrate the projected total employment in Region A, Region B, and Region C, respectively, that would result from each development scenario. As shown on the figures, total employment levels would be greatest in Year 10 through Year 30. Once new well construction ends in Year 30, the projected direct and indirect employment would be greatly reduced.

Figure 6.17 – Projected Total Employment in Region A Under Each Development Scenario (New August 2011)

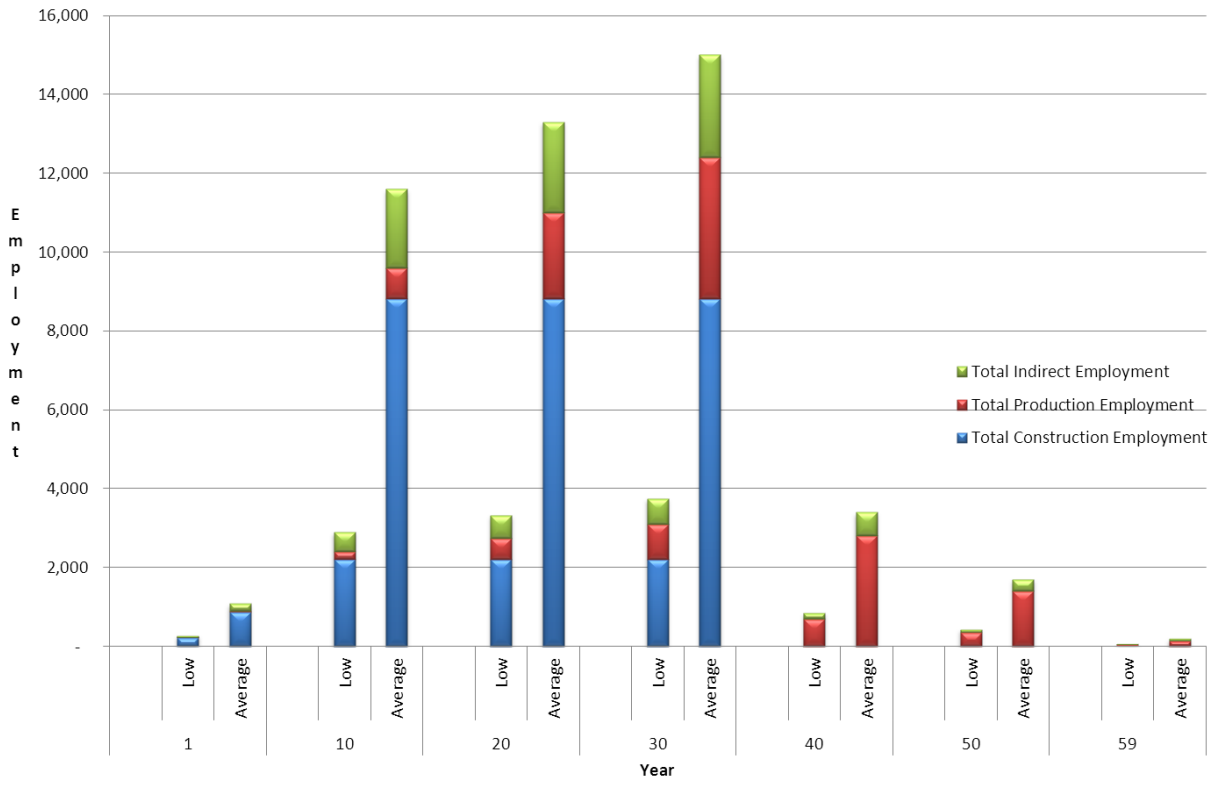


Figure 6.18 - Projected Total Employment in Region B Under Each Development Scenario (New August 2011)

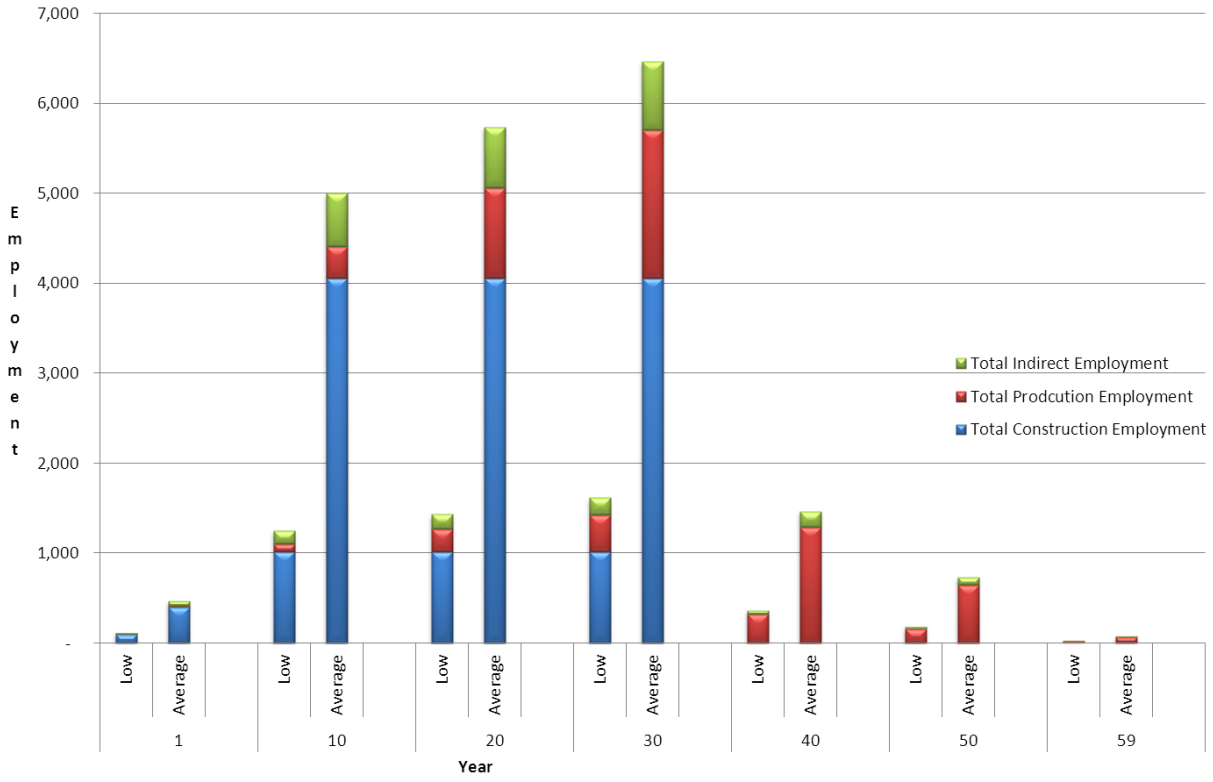
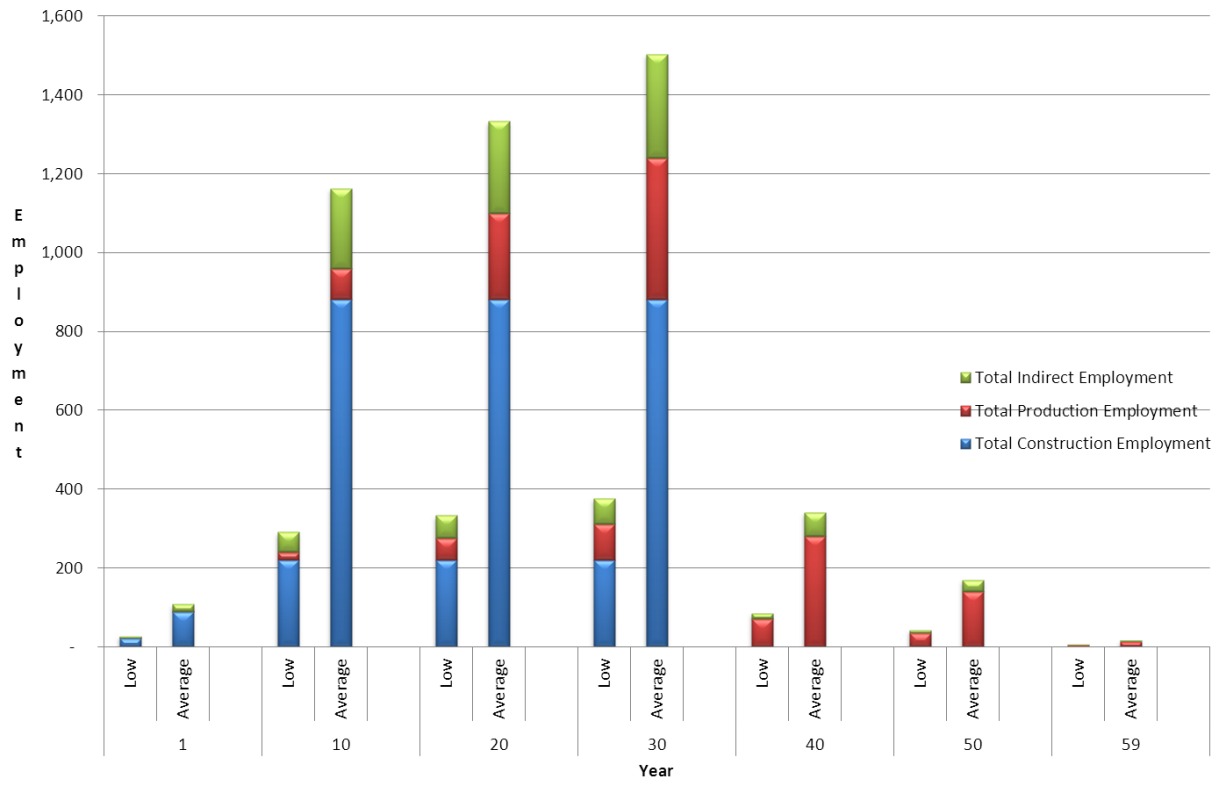


Figure 6.19 - Projected Total Employment in Region C Under Each Development Scenario (New August 2011)



The proposed use of high-volume hydraulic fracturing would have a significant, positive impact on employment in New York State as a whole and in the affected communities. However, the distribution of these positive employment impacts would not be evenly distributed throughout the state or even throughout the areas where low-permeable shale is located. Many geological and economic factors would interact to determine the exact location that wells would be drilled. The location of productive wells would determine the distribution of impacts.

In some regions in the state where drilling is most likely to occur, the increases in employment may be so large that these regions may experience some short-term labor shortages. The increase in direct and indirect employment related to the natural gas extraction industry could drive wage rates up in the areas in the short term and make it more difficult for existing industries to recruit and retain qualified workers. In addition, the increase in wage rates could have a short-term, negative impact on existing industries as it would increase their labor costs. These potential short-term labor impacts would be less severe because specialized labor from

outside the region would likely be required for certain jobs, and the existence of employment opportunities would cause the migration of workers into the region. In addition, the positive employment impacts from well construction and development—and the related economic impacts derived from that employment—would generate more in-migration to the region. In time, the additional new residents to the areas would expand the regional labor force and reduce the pressure on labor costs.

Income

The increase in direct and indirect employment would have a positive impact on income levels in regions where natural gas development occurs. Table 6.36 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 to Year 30), total annual construction earnings in a region could range from a low of $15.0 million in Region C under the low development scenario to nearly $597.0 million under the average development scenario in Region A. In Year 30, the year that the maximum number of production workers are assumed to be employed, regional employee earnings from production employment could range from a low of $6.1 million in Region C under the low development scenario to a high of $242.4 million in Region A under the average development scenario.

Table 6.36 - Maximum Direct and Indirect Earnings Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Earnings[1]	$149.2	$597.0
Production Earnings[2]	$60.6	
Indirect Earnings Impacts[3]	**$44.0**	**$176.0**
Total Earnings Impacts	**$253.8**	**$1,015.4**
Total Earnings as a Percentage of Region A's 2009 Total Wages	4.7%	18.7%
Region B		
Direct Earnings Impacts		
Construction Earnings[1]	$68.6	$274.6
Production Earnings[2]	$27.9	$111.5
Indirect Earnings Impacts[3]	**$12.9**	**$51.6**

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Total Earnings Impacts	**$109.4**	**$437.7**
Total Earnings as a Percentage of Region B's 2009 Total Wages	4.8%	19.3%
Region C		
Direct Earnings Impacts		
Construction Earnings[1]	$15.0	$59.7
Production Earnings[2]	$6.1	$24.2
Indirect Earnings Impacts[3]	$4.5	$17.8
Total Earnings Impacts	$25.6	$101.7
Total Earnings as a Percent of Region C's 2009 Total Wages	0.9%	3.7%

Source: U.S. Bureau of Economic Analysis 2011b, 2011c, 2011d; NYSDOL 2009.

[1] These figures represent the maximum annual construction earnings under each scenario and correspond to construction earnings in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction earnings for all other years.

[2] These figures represent the maximum annual production earnings under each development scenario. These figures correspond to production employee earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected production and indirect employee earnings for all other years.

[3] Separate Type I direct earnings multipliers for the oil and gas extraction industry from the US Bureau of Economic Analysis, Regional Input- Output Modeling System (RIMS II) for each region were used to estimate the indirect employment impacts.

Total employee earnings in all of the regions are expected to increase significantly. Region A would experience annual increases in employee earnings of approximately $254 million to $1.0 billion, or 4.7% to 18.7% of the 2009 total wages and salaries for the region. Similarly, Region B would experience annual increases in employee earnings of approximately $109 million to $438 million, or 4.8% to 19.3% of 2009 total wages and salaries for the region. Region C would also experience a significant impact in its annual employee earnings. Employee earnings in this region would increase from approximately $26 million to $102 million, or 0.9% to 3.7% of the 2009 total wages and salaries for the region (see Table 6.36).

Owners of the subsurface mineral rights where wells are drilled would also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or greater of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas

production is at its peak, could result in significant increases in income. In addition, mineral rights owners often receive large signing bonuses/bonus bids as part of the lease agreements.

Impacts on Other Industries

The proposed high-volume hydraulic-fracturing operations would affect not only the size of the regional economies as described above, but would also have an impact on other industries in the economy.

As previously described, suppliers of the natural gas extraction industry would experience significant increases in demand for their goods and services. Over time, these industries would expand and their importance in the regional economies would likewise increase. As shown in Section 2.4.11, Economy, Employment, and Income, the industries expected to experience the greatest indirect, or secondary, growth due to expansion of the natural gas extraction industry would be real estate; the professional, scientific, and technical industries; the management of companies and enterprises; construction; and manufacturing industries. For every $1 million change in the final demand generated in the natural gas extraction industry, a corresponding significant level of output would be generated in these industries. Typically, a change in final demand in an industry is defined as the change in output of that industry multiplied by the value or price of its output. In this case, a $1 million increase in the value of output from the natural gas extraction industry would generate $47,100 in the real estate and rental and leasing industry; $30,500 in the professional, scientific, and technical services industry; and $27,600 in the management of companies and enterprises industry. See Section 2.4.15 for a discussion of indirect impacts on other industries in New York State.

Each of these secondary industries would experience increases in their output, employment, income and value added. As a result, industries that supply these secondary industries would also experience a positive economic impact, and they would expand as demand for their goods and services increases. Secondary, and eventually even tertiary, suppliers would start to tailor their products to meet the needs of the natural gas extraction industry.

Conversely, some industries in the regional economies may contract as a result of the proposed natural gas development. Negative externalities associated with the natural gas drilling and

production could have a negative impact on some industries such as tourism and agriculture. Negative changes to the amenities and aesthetics in an area could have some effect on the number of tourists that visit a region, and thereby impact the tourism industry. However, as shown by the tourism statistics provided for Region C, Cattaraugus and Chautauqua Counties still have healthy tourism sectors despite having more than 3,900 active natural gas wells in the region.

Similarly, agricultural production in the heavily developed regions may experience some decline as productive agricultural land is taken out of use and is developed by the natural gas industry. Property values also may experience some increase as a result of the natural gas development and the resulting increase in economic activity. The potential increase in land prices, which is one of the main factors of production for agriculture, could impact the industry's input costs in areas experiencing the most intense development.

6.8.2 Population

This section presents a summary of the population and demographic findings of the Economic Assessment Report (2011) written by Ecology and Environment Engineering, P.C.

As described previously, three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels. The designation of these areas as representative regions does not mean that the impacts would necessarily be limited to those areas. Until the production potential of low-permeability reservoirs is proven, it is not possible to predict where every potential high-volume hydraulically fractured well may be sited; wells could be developed anywhere there is low-permeability shale. The local and regional impacts presented here are intended only to provide order-of-magnitude estimates for the range of potential impacts. See the Economic Assessment Report for a more detailed discussion on the selection of these representative regions.

To assess the maximum potential population impacts, the discussion below is based on a hypothetical situation in which all workers hired for the construction and production phases of the natural gas wells either migrate into the regions from other areas, or workers migrate into the regions from other areas to fill positions which local construction and production workers vacate

to work on the natural gas wells.. Although this hypothetical situation is used to examine the maximum potential population impacts, it is more likely that the actual outcome would be less than described. Not all workers employed during the construction and production phases would necessarily live in New York State or one of the representative regions. Particularly in the case of well development and production in the Southern Tier, existing natural gas workers currently residing in Pennsylvania, for example, may simply choose to maintain their residency in Pennsylvania and commute to work in New York.

In addition, actual population impacts may also be less than what is described in the following section because some currently unemployed or underemployed local workers could be hired to fill some of the construction and production positions, thereby, reducing the total in-migration to the region.

The hiring of currently employed local workers (i.e., those workers that leave existing jobs to work in the natural gas industry) is not expected to reduce total in-migration to the regions as it is assumed that the jobs these local workers are leaving would need to be filled. Given the finite number of workers in the regional labor force, any growth in the total number of jobs available in regional economies not filled by currently unemployed or underemployed persons would lead to in-migration to the areas.

The following additional assumptions were used to project population impacts:

- The majority of construction jobs and related population migration to the regions would be temporary and transient in nature in the beginning of the well development phase. As well construction continues, these jobs would gradually be filled by permanent residents.

- Transient construction workers are assumed to temporarily relocate to the region for a short-duration and are assumed to not be accompanied by their households. Permanent construction workers are assumed to relocate to the region for the duration of the well development phase and would be accompanied by their entire households.

- Production jobs and related population migration to the regions would be permanent and entire households would relocate to the regions.

- Natural gas development and production would not “crowd out” employment in other unrelated industrial sectors, and employment in these sectors would remain unchanged.

- Job vacancies created when local employees leave existing industries to take jobs in the natural gas extraction industry would be filled.

- The 2010 average household sizes in New York State (2.64 persons per household), Region A (2.47 persons per household), Region B (2.52 persons per household), and Region C (2.49 persons per household) were used in estimating the population impacts associated with permanent construction and production jobs (USCB 2010).

- There would be no involuntary displacement of persons due to construction of the natural gas wells, as no buildings would be demolished to make way for wells and wells need to be drilled at least 500 feet away from private wells and 100 feet from inhabitated dwellings.

6.8.2.1 New York State

Both transient and permanent population impacts are expected to occur as a result of natural gas well construction. Given the highly specialized nature of natural gas construction, workers with the skills required to complete a high-volume hydraulic fracturing operation would not be currently available in New York State or in the representative regions. If high-volume hydraulic fracturing operations were to begin in New York State, most of the skilled workers would initially need to be recruited from outside the state and would be both temporary and transient in nature.

As the industry matures and as more natural gas development occurs in the state and representative regions, more local persons would acquire the requisite skills needed for these jobs, and recruitment from within the existing labor force would therefore increase. Also, as the industry expands and development becomes more assured, the incentive for previously transient workers to become permanent residents within the state or representative regions would increase. Therefore, it would be expected that eventually there would be a decline in the number of transient construction workers and an increase in the number of permanent construction workers.

In an effort to estimate the mix of transient and permanent construction workers, data collected by the Marcellus Shale Education and Training Center on the occupational composition of the natural gas workforce and data from the U.S. Bureau of Economic Analysis' 2008 National Employment Matrix were used to help forecast the amount of local labor that would be employed in natural gas well development (Marcellus Shale Education and Training Center 2009; U.S. Bureau of Economic Analysis 2011e). Initially no more than 23% of the construction

workforce is expected to be hired locally. Due to New York State's small existing natural gas industry, the remaining 77% of the workforce would have specialized skills that would most likely be unavailable among New York's labor force in Year 1. Given the newness of the industry, it is assumed that, in Year 1, 77% of the total workforce would be transient workers from outside the state.

As the natural gas industry matures the number of qualified workers in the state and representative regions would increase. This pool of qualified workers would expand as existing local residents gain the requisite skills and/or formerly transient workers permanently relocate to the state or representative regions. The total number of transient construction workers would gradually increase as the rate of well development increased until Year 10 when the maximum number of transient construction workers under both development scenarios is reached. From Years 11 to 30 the transient population would gradually decrease as a proportion of the total construction workforce. By Year 30 it is assumed that the natural gas industry would be sufficiently mature that 90% of all workers could be hired locally. Table 6.37 shows the transient, permanent, and total construction employment for select years. See the Economic Assessment Report for a more detailed discussion of how these figures were derived.

Table 6.37 - Transient, Permanent and Total Construction Employment Under Each Development Scenario for Select Years: New York State (New August 2011)

	Low Scenario			**Average Scenario**		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	342	97	439	1,370	389	1,759
5	1,517	693	2,210	6,051	2,766	8,817
10	2,409	1,999	4,408	9,639	7,995	17,634
15	1,759	2,649	4,408	7,038	10,596	17,634
20	1,181	3,227	4,408	4,725	12,909	17,634
25	740	3,668	4,408	2,959	14,675	17,634
30	441	3,967	4,408	1,763	15,871	17,634

Since the natural gas wells are expected to stay in operation for 30 years, production workers are assumed to be permanent workers who reside close to where the wells are located. Thus, these workers would live in or relocate their families to the area. Wells drilled in Year 1 are expected

to remain in operation until Year 30; wells drilled in Year 30 would remain in operation until Year 60.

It is assumed that the households of permanent construction workers and production workers would, on average, be the same size as existing New York households (i.e., 2.64 persons, including the single worker). Therefore, in projecting population impacts, it is anticipated that transient construction workers would be temporary residents unaccompanied by family members, whereas permanent construction workers and all production workers would be permanent residents accompanied by an average of 1.64 family members.

Based on the above assumptions, Table 6.38 displays, for New York State as a whole and for each development scenario, the estimated transient and permanent populations resulting from construction and production activities for Years 1, 10, 20, 30, 40, 50, and 59.

Table 6.38 - Estimated Population Associated with Construction and Production Employment for Select Years: New York State (New August 2011)

		Transient Population	**Permanent Population**		
Production Year	**Development Scenario**	**Construction**	**Construction**	**Production**	**Total**
1	Low	342	256	18	275
	Average	1,370	1,026	74	1,100
10	Low	2,409	5,277	1,019	6,296
	Average	9,639	21,107	4,079	25,186
20	Low	1,181	8,519	2,872	11,392
	Average	4,725	34,080	11,492	45,572
30	Low	441	10,473	4,726	15,198
	Average	1,763	41,898	18,905	60,803
40	Low	0	0	3,707	3,707
	Average	0	0	14,829	14,829
50	Low	0	0	1,853	1,853
	Average	0	0	7,413	7,413
59[1]	Low	0	0	185	185
	Average	0	0	742	742

Note:

[1] Year 59 is used instead of Year 60 since it is assumed that all operational wells would cease production at the beginning of Year 60.

Under the low development scenario, between Years 10 and 30, it is projected that a maximum of 4,408 construction workers would temporarily or permanently migrate into the areas. The maximum transient construction workforce would occur in Year 10, with an estimated 2,409 transient workers. (During this same year, there would be 1,999 permanent workers relocating to the area.) Under the average development scenario, between Years 10 and 30, it is projected that a maximum of 17,634 construction workers would temporarily or permanently migrate to the well construction areas. The maximum transient workforce would occur in Year 10, with an estimated 9,639 transient workers. (During this same time period, there would be 7,995 permanent workers relocating to the area.) The population impact of the maximum number of transient workers, 9,639 transient workers for the average development scenario, represents less than 0.1% of the total present population of New York State, indicating that transient workers would have only a minor short-term population impact at the state level.

Under the low development scenario, the number of persons permanently migrating to the impacted areas to construct and operate the wells is projected to reach its maximum of 15,198 persons during Year 30 (see Table 6.39). Under the average development scenario during Year 30, it is projected that 60,803 persons would permanently migrate to the impacted areas. Since it is assumed that permanent construction and production workers would relocate with their households, these population estimates include the permanent construction and production workers and members of their households. The maximum impact on the permanent population under the average development scenario is 60,803 persons in Year 30. This figure represents approximately 0.3% of the total present population of New York State, indicating that some long-term population impact could occur at the state level as a result of the operation of the new natural gas wells.

Table 6.39 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production: New York State (New August 2011)

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts [3]	% Increase from Total Existing 2010 Population
New York State	19,378,102	Low	2,409	>0.1%	15,198	>0.1%
		Average	9,639	>0.1%	60,803	0.3%

Notes:

[1] Existing population from U.S. Census Bureau's *2010 Census of Population* (USCB 2010).

[2] Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

[3] Maximum operational impacts occur during production year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

According to the population projections developed by Jan K. Vink of the Cornell University Program on Applied Demographics, the population of New York State is expected to increase by 1,037,344 persons over the next 20 years (i.e., by an average of approximately 52,000 persons per year) (Cornell University 2009). Consequently, the maximum cumulative population impact of 60,803 persons, which occurs during production year 30, is slightly more than one year's projected incremental population growth for New York State.

Although the maximum population impacts would be relatively minor at the level of the whole state, natural gas wells would not be spread evenly across the state; they would be concentrated in particular areas where the influx of construction workers and production workers and their families may have more significant population impacts. Similarly, because new wells would not be developed evenly over time due to swings in well development activity, the population impacts would be greater in some years than in others.

In addition to direct employment (employment impacts from construction and production), there are projected indirect employment impacts from the development of hydraulic fracturing operations in the area underlain by the Marcellus and Utica Shales (see Section 6.10.1). Given the relatively high unemployment rates currently being experienced in these regions, it is likely that some of these new, indirectly created jobs (e.g., gas station clerks, hotel lobby personnel,

etc.) would be filled by local, previously unemployed or underemployed persons. These indirect employment impacts would reduce local unemployment and help stimulate the local economies. The impacts associated with the influx of construction workers, both transient and permanent, would last as long as wells are being developed in an area, whereas the impacts associated with the production phase could last up to 60 years.

6.8.2.2 Representative Regions

Table 6.40,Table 6.41 and Table 6.42 show the estimated transient, permanent, and total construction employment for Regions A, B, and C under the low and average development scenario.

Table 6.40 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region A (New August 2011)

	Low Scenario			**Average Scenario**		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	171	48	219	686	194	880
5	758	347	1,105	3,026	1,383	4,409
10	1,205	999	2,204	4,820	3,998	8,818
15	880	1,324	2,204	3,520	5,298	8,818
20	591	1,613	2,204	2,363	6,455	8,818
25	370	1,834	2,204	1,480	7,338	8,818
30	220	1,984	2,204	882	7,936	8,818

Table 6.41 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region B (New August 2011)

	Low Scenario			**Average Scenario**		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	79	22	101	315	89	404
5	349	159	508	1,392	636	2,028
10	554	460	1,014	2,217	1,839	4,056
15	405	609	1,014	1,619	2,437	4,056
20	272	742	1,014	1,087	2,969	4,056
25	170	844	1,014	681	3,375	4,056
30	101	913	1,014	406	3,650	4,056

Table 6.42 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region C (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	17	5	22	69	19	88
5	75	35	110	303	138	441
10	121	100	221	482	400	882
15	88	133	221	352	530	882
20	59	162	221	236	646	882
25	37	184	221	148	734	882
30	22	199	221	88	794	882

Table 6.43 shows the maximum population impacts associated with transient and permanent construction workers and permanent production workers for the three representative regions. As noted above, the three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels, and the projected local and regional impacts presented here are intended to provide order-of-magnitude estimates for the range of potential impacts. In constructing Table 6.43 it was assumed, as discussed above, that a portion of the construction workers would be temporary, transient residents in an area and would not be accompanied by members of their households. The remainder of the construction workers would be permanent residents. The proportion of permanent workers to transient workers would gradually increase over time. All production workers are assumed to be permanent residents and would relocate their families to the area. Since the households of permanent construction and production workers are assumed to be the same size as average households in their respective regions, permanent workers are assumed to be accompanied by an average of 1.47 family members in Region A, 1.52 family members in Region B, and 1.49 family workers in Region C.

Table 6.43 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts [3]	% Increase from Total Existing 2010 Population
A	340,555	Low	1,205	0.4%	7,111	2.1%
		Average	4,820	1.4%	28,447	8.4%
B	187,786	Low	554	0.3%	3,339	1.8%
		Average	2,217	1.2%	13,348	7.1%
C	215,222	Low	121	<0.1%	720	0.3%
		Average	482	0.2%	2,868	1.3%

Notes:

[1] Existing population from US Census Bureau's *2010 Census of Population* (USCB 2010).

[2] Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

[3] Maximum permanent impacts occur during production Year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

The upper bound of the potential impacts is found in Region A under the average development scenario, when in Year 10 there are projected to be 4,820 unaccompanied transient workers, representing 1.4% of the region's total population. The upper bound of the potential impacts from permanent population changes can be found in Region A under the average development scenario in Year 30, when 28,447 permanent construction and production workers and their household members would be residing in the region. This figure represents 8.4% of the existing population in Region A. According to the population projections presented in Section 2.4.11, in the absence of gas well development, Region A is expected to experience a future population decrease and to have a 2030 population of 279,675 persons, a decrease of 60,880 persons, equal to 17.9% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 28,447persons in Year 30 under the average development scenario, would offset approximately 47% of the projected population decline in Region A and would, therefore, have a beneficial impact.

Under the average development scenario, Region B is projected to have a maximum of 2,217 unaccompanied, transient construction workers and 13,348 permanent construction and

production workers and their family members residing in the region. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. The maximum transient population would account for 1.2% of the existing population in Region B, and the maximum permanent population would account for 7.1% of the existing population, respectively. According to population projection figures presented in Section 2.4.11, in the absence of gas well development, Region B is expected to experience a future population decrease and to have a 2030 population of 183,031 persons, a decrease of 4,755 persons, equal to 2.5% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 13,348 persons in Year 30 under the average development scenario, would more than offset the projected population decline in Region B but would not add significantly to the existing population.

The lowest maximum potential population impact is found in Region C under the low development scenario, when in Year 10 only 121 unaccompanied, transient construction workers are expected to reside in the region. Under the same development scenario 720 permanent construction and production workers and their families would reside in Region C in Year 30, representing a total of approximately 1.3% of the existing population. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. In contrast, under the average development scenario in Year 30, Region C is projected to have a maximum of 482 unaccompanied, transient construction workers and a maximum of 2,868 permanent construction and production workers and household members in the region. The maximum transient population represents 0.2% of the existing population, and the maximum permanent population represents 1.3% of the existing population. According to population projection figures presented in Section 2.4.11, in the absence of gas well development, Region C is expected to experience a future population decrease and to have a 2030 population of 188,752 persons, a decrease of 26,470 persons, equal to 12.3% of the total existing population. The influx of permanent workers and their family members associated with gas well development, totaling 2,868 persons in Year 30 under the average development scenario, would offset more than 10% of the projected population decline in Region C and would have a small-scale beneficial impact.

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 5

Natural Resources Defense Council, Earthjustice, and Sierra Club, *Comments [to EPA] on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels* (June 29, 2011)

January 27, 2012

June 29, 2011

Office of Groundwater and Drinking Water
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Comments on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels

Dear Sir or Madam:

Thank you for the opportunity to provide comments on the Environmental Protection Agency's ("EPA") development of UIC Class II permitting guidance for hydraulic fracturing activities that use diesel fuels in fracturing fluids.

The Natural Resources Defense Council ("NRDC") is a national, non-profit legal and scientific organization with 1.3 million members and activists worldwide. Since its founding in 1970, NRDC has been active on a wide range of environmental issues, including fossil fuel extraction and drinking water protection. NRDC is actively engaged in issues surrounding oil and gas development and hydraulic fracturing, particularly in the Rocky Mountain West and Marcellus Shale regions.

Earthjustice is a non-profit public interest law firm originally founded in 1971. Earthjustice works to protect natural resources and the environment, and to defend the right of all people to a healthy environment. Earthjustice is actively addressing threats to air, water, public health and wildlife from oil and gas development and hydraulic fracturing in the Marcellus Shale and Rocky Mountain regions.

Founded in 1892, the Sierra Club works to protect communities, wild places, and the planet itself. With 1.4 million members and activists worldwide, the Club works to provide healthy communities in which to live, smart energy solutions to combat global warming, and an enduring legacy of for America's wild places. The Sierra club is actively addressing the environmental threats to our land, water, air from natural gas extraction across the United States.

General Comments

We appreciate EPA's decision to issue permitting guidance for hydraulic fracturing using diesel fuel. While this practice is regulated under the currently existing UIC Class II regulations, hydraulic fracturing also poses unique risks to USDWs. For that reason, we believe that EPA must promulgate new regulations in addition to permitting guidance. The issuance of permitting guidance under Class II is an important stopgap, but only through regulation that specifically address hydraulic fracturing using diesel can USDWs be adequately protected.

UNPERMITTED INJECTION OF DIESEL FUELS THROUGH HYDRAULIC FRACTURING IS A VIOLATION OF THE SAFE DRINKING WATER ACT

As an initial matter, EPA should use its proposed guidance to reemphasize an important point: the use of diesel fuel injection for hydraulic fracturing is already subject to the requirements of the Safe Drinking Water Act ("SDWA"), whether or not it is specifically addressed by EPA guidance or state UIC programs.

The statutory definition of "underground injection" as "the subsurface emplacement of fluids by well injection" plainly encompasses hydraulic fracturing. 42 U.S.C. § 300h(d)(1); see, e.g., Legal Environmental Assistance Found. v. EPA, 118 F.3d 1467, 1475 (11th Cir. 1997) (holding that the statute requires EPA to regulate hydraulic fracturing operations). SDWA underscores this point by excluding hydraulic fracturing from the definition of "underground injection," except where diesel fuel is used. 42 U.S.C. § 300h(d)(1)(B)(ii). Such an exclusion would be unnecessary if hydraulic fracturing were not otherwise a form of SDWA-regulated underground injection.

Because it represents a form of underground injection, all hydraulic fracturing with diesel fuel violates SDWA unless a permit has been issued. 42 U.S.C. § 300h(b)(1)(A); 40 C.F.R. §§ 144.1(d)(6), (g), 144.11.

Because diesel fuel contains carcinogenic benzene, toluene, ethylene, and xlyene ("BTEX") compounds it poses a major concern.[1] Therefore, when Congress exempted some hydraulic fracturing injections from the Act, it explicitly limited that exemption to wells where fluids "other than diesel fuels" are used. 42 U.S.C. § 300h(d)(1)(B)(ii).[2] For those hydraulic fracturing injections using diesel fuel, the SDWA Class II well program applies. See 40 C.F.R. § 144.6(b).

Nevertheless, many companies have continued to use diesel fuel without obtaining a permit. The minority staff of the House Committee on Energy and Commerce determined that between 2005 and 2009 "oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[3] The investigators determined that "no oil and gas service companies have sought – and no state and federal regulators have issued – permits for diesel fuel use in hydraulic fracturing."[4]

In light of this noncompliance (and assertions of confusion on the part of hydraulic fracturing service companies), EPA should reaffirm that these injections were illegal, and future injections without a permit are also illegal.

EPA should further clarify that these injections were barred under SDWA whether or not they occurred in a state with primacy to enforce SDWA, and whether or not such states had rules on the books. This is so because the SDWA requires each state to prohibit unpermitted injections. 42 U.S.C. § 300h(b)(1)(A).

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[1] For example, EPA described diesel as the "additive of greatest concern" in hydraulic fracturing operations.US EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (June 2004) at ES-12.

[2] Of course, "[n]otwithstanding any other provision of [the SDWA]," including the hydraulic fracturing exemption, EPA retains its power to act against injection practices which "may present an imminent and substantial endangerment to the health of persons." 42 U.S.C. § 300i(a). EPA could also use this authority to address diesel injection.

[3] Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2001) at 1.

[4] *Id.*; *see also* Dusty Horwitt, Environmental Working Group, *Drilling Around the Law* (2009) at 12-13 (documenting state and federal agency officials' failure to regulate these injections).

The statute leaves no room for states to simply ignore illegal injections to which the Act applies. Moreover, the SDWA regulations provide that each state program "must be administered in accordance" with various federal regulations, including 40 C.F.R. § 144.11, which prohibits "[a]ny underground injection, except into a well authorized by rule or except as authorized by permit." 40 C.F.R. § 145.11(a)(5). Thus, even if a state's rules do not explicitly address hydraulic fracturing injections with diesel fuel, the Class II permitting rules remain in place and govern all such injections.[5]

As the Congressional investigation demonstrates, oil and gas companies ignored these clear requirements.[6] In light of this apparently common failure to comply with the law, EPA would be well within its authority to ban diesel injection entirely. Diesel fuel injection is an inherent threat to safe drinking water. Cf. 42 U.S.C. § 300h(b)(1)(B) (applicants for permits must satisfactorily demonstrate that "the underground injection will not endanger drinking water sources"). Companies can and should be required to avoid using diesel fuel in their operations. But if EPA does not do so, it should at a minimum limit the threats it poses by issuing strong guidance and requiring permits to control injection practices.

Responses to EPA's Discussion Questions

WHAT SHOULD BE CONSIDERED AS "DIESEL FUELS?

The injection of any quantity of diesel fuels for hydraulic fracturing should be covered under EPA's UIC Class II regulations. This includes products derived from, containing, or mixed with diesel fuels or any fuel which could be used in a diesel engine.

At 40 CFR §80.2(x), "diesel fuel" is defined as:

Diesel fuel means any fuel sold in any State or Territory of the United States and suitable for use in diesel engines, and that is—

(1) A distillate fuel commonly or commercially known or sold as No. 1 diesel fuel or No. 2 diesel fuel;

(2) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (e.g. , biodiesel fuel); or

(3) A mixture of fuels meeting the criteria of paragraphs (1) and (2) of this definition.

WHAT WELL CONSTRUCTION REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

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[5] States which do not enforce against scofflaw injectors risk their primacy, as EPA should make clear. *See* 42 U.S.C. § 300h(c) (providing that if EPA determines that "a state no longer meetings the requirements" of the SDWA, then EPA shall implement a federal program).

[6] Indeed, even diesel injection into wells permitted by rule is barred if the operator did not comply with the Class II regulations. These applicable rules include EPA's inventory requirements at 40 C.F.R. § 144.26, which trigger reporting of well location and operating status, and, for EPA-administered programs, reports on the "nature of injected fluids" and on the mechanical integrity of the well. *See* 40 C.F.R. § 144.22(prohibiting injection without inventory reporting). If operators inject into permitted-by-rule wells without complying with these and other applicable requirements, they further violate the SDWA.

Casing and Cement

Proper well construction is crucial to ensuring protection of USDWs. The first step to ensuring good well construction is ensuring proper well drilling techniques are used. This includes appropriate drilling fluid selection, to ensure that the wellbore will be properly conditioned and to minimize borehole breakouts and rugosity that may complicate casing and cementing operations. Geologic, engineering, and drilling data can provide indications of potential complications to achieving good well construction, such as highly porous or fractured intervals, lost circulation events, abnormally pressured zones, or drilling "kicks" or "shows." These must be accounted for in designing and implementing the casing and cementing program. Reviewing data from offset wellbores can be helpful in anticipating and mitigating potential drilling and construction problems. Additionally, proper wellbore cleaning and conditioning techniques must be used to remove drilling mud and ensure good cement placement.

Hydraulic fracturing requires fluid to be injected into the well at high pressure and therefore wells must be appropriately designed and constructed to withstand this pressure. The casing and cementing program must:

- Properly control formation pressures and fluids
- Prevent the direct or indirect release of fluids from any stratum to the surface
- Prevent communication between separate hydrocarbon-bearing strata
- Protect freshwater aquifers/useable water from contamination
- Support unconsolidated sediments
- Protect and/or isolate lost circulation zones, abnormally pressured zones, and any prospectively valuable mineral deposits

Casing must be designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; corrosion; erosion; and hydraulic fracturing pressure. The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well.

UIC Class II rules require that injection wells be cased and cemented to prevent movement of fluids into or between underground sources of drinking water and that the casing and cement be designed for the life of the well [40 CFR §146.22(b)(1)]. Achieving and maintaining mechanical integrity are crucial to ensuring these requirements. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. Internal mechanical integrity refers to the absence of leakage pathways through the casing; external mechanical integrity refers to the absence of leakage pathways outside the casing, primarily through the cement.

The components of a well that ensure the protection and isolation of USDWs are steel casing and cement. Multiple strings of casing are used in the construction of oil and gas wells, including: conductor casing, surface casing, production casing, and potentially intermediate casing. For all casing strings, the design and construction should be based on Good Engineering Practices (GEP), Best Available Technology (BAT), and local and regional engineering and geologic data. All well construction materials

must be compatible with fluids with which they may come into contact and be resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

Conductor Casing:
Conductor casing is typically the first piece of casing installed and provides structural integrity and a conduit for fluids to drill the next section of the well. Setting depth is based on local geologic and engineering factors but is generally relatively shallow, typically down to bedrock. Depending on local conditions, conductor casing can either be driven into the ground or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, the space between the casing and the wellbore – the annulus – should be fully cemented from the base, or "shoe," of the casing to the ground surface, a practice referred to as "cementing to surface." A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

Surface Casing:
Surface casing is used to: isolate and protect groundwater from drilling fluids, hydrocarbons, formation fluids, and other contaminants; provide a stable foundation for blowout prevention equipment; and provide a conduit for drilling fluids to drill the next section of the well.

Surface casing setting depth must be based on relevant engineering and geologic factors, but generally should be:

1. Shallower than any pressurized hydrocarbon-bearing zones
2. 100 feet below the deepest USDW

Surface casing must be fully cemented to surface by the pump and plug method. If cement returns are not observed at the surface, remedial cementing must be performed to cement the casing from the top of cement to the ground surface. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of USDWs.

Intermediate Casing:
Depending on local geologic and engineering factors, one or more strings of intermediate casing may be required. This will depend on factors including but not limited to the depth of the well, the presence of hydrocarbon-or fluid-bearing formations, abnormally pressured zones, lost circulation zones, or other drilling hazards. When used, intermediate casing should be fully cemented from the shoe to the surface by the pump and plug method. Where this is not possible or practical, the cement must extend from the casing shoe to 600 feet above the top of the shallowest zone to be isolated (e.g. productive zone, abnormally pressured zone, etc). Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids.

Production Casing:
To be most protective, one long-string production casing (i.e. casing that extends from the total depth of the well to the surface) should be used. This is preferable to the use of a production liner – in which the

casing does not extend to surface but is instead “hung” off an intermediate string of casing – as it provides an additional barrier to protect groundwater. The cementing requirements are the same as for intermediate casing.

Production Liner:
If production liner is used instead of long-string casing, the top of the liner must be hung at least 200 feet above previous casing shoe. The cementing requirements for production liners should be the same as for intermediate and production casing.

General:
For surface, intermediate, and production casing, a sufficient number of casing centralizers must be used to ensure that the casing is centered in the hole and in accordance with API Spec 10D (Specification for Bow-Spring Casing Centralizers) and API RP 10D-2 (Recommended Practice for Centralizer Placement and Stop Collar Testing). This is necessary to ensure that the cement is distributed evenly around the casing and is particularly important for directional and horizontal wells. In deviated wells, the casing will rest on the low side of the wellbore if not properly centralized, resulting in gaps in the cement sheath where the casing makes direct contact with the rock. Casing collars should have a minimum clearance of 0.5 inch on all sides to ensure a uniformly concentric cement sheath.

For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud and exclude the use of synthetic or oil-based mud or other chemicals. This typically applies to the surface casing and possibly conductor casing portions of the hole.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, all surface, intermediate, and production casing strings should be pressure tested. Drilling may not be resumed until a satisfactory pressure test is obtained. Casing must be pressure tested to a minimum of 0.22 psi/foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield. If the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak, corrective action must be taken.

Cement compressive strength tests must be performed on all surface, intermediate, and production casing strings. Casing must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi. The cement mixture must have a 72-hour compressive strength of at least 1200 psi. Additionally, the API free water separation must average no more than six milliliters per 250 milliliters of cement, tested in accordance with API RP 10B-2.

For cement mixtures without published compressive strength tests, the operator or service company must perform such tests in accordance with the current API RP 10B-6 and provide the results of these tests to regulators prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, casing shoe tests should be performed immediately after drilling out of the surface or intermediate casing. These may include Formation Integrity Tests (FIT), Leak-Off Tests (LOT or XLOT), and pressure fall-off or pump tests. Casing shoe tests are used to ensure casing and cement integrity, determine whether the formations below the casing shoe can withstand the pressure to which they will be subjected while drilling the next section of the well, and gather data on rock mechanical properties. If any of the casing shoe tests fail, remedial action must be taken to ensure that no migrations pathways exist. Alternatively, the casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

UIC Class II rules require that cement bond, temperature, or density logs be run after installing surface, intermediate, and production casing and cement [40 CFR §146.22(f)(2)(i)(B)]. Ideally, all three types of logs should be run. The term "cement bond log" refers to out-dated technology and the terms "cement evaluation logs," "cement integrity logs" or "cement mapping logs" are preferable. Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. A poor cement job, in which the cement contains air pockets or otherwise does not form a complete bond between the rock and casing or between casing strings, can allow fluids to move behind casing from the reservoir into USDWs. Verifying the integrity of the cement job is crucial to ensure no unintended migration of fluids. Traditional bond logs cannot detect the fine scale channeling which may allow fluids to slowly migrate over years or decades and therefore the use of more advanced cement evaluation logs is crucial. (For further reading see, e.g., Lockyear et. al, 1990; Frisch et. al, 2005)

When well construction is completed, the operator should certify, in writing, that the casing and cementing requirements were met for each casing string.

In addition, it may be useful to review the casing and cementing regulations of states with long histories of oil and gas production such as Texas, Alaska, California, and Pennsylvania. Specific examples include:

- Requirements for casing and cementing record keeping for casing and cementing operations in the California Code of Regulations (CCR) at 14 CCR §1724
- Requirements for casing and cementing program application content in the Alaska Administrative Code (AAC) at 20 AAC §25.030(a)
- Cement chemical and physical degradation standard in the Pennsylvania Code (Pa. Code) at 25 Pa. Code §78.85(a)
- Requirement to report and repair defective casing or take the well out of service in the Pennsylvania Code at 25 Pa. Code §78.86
- Casing standard in gas storage areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with gas storage
- Casing standard in coal development areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with sufficient coal seams
- Casing testing and minimum overlap length standards in the California Code of Regulations at 14 CCR §1722

- Cement quality, testing, and remedial repair standard in the Alaska Administrative Code at 20 AAC §25.030
- Casing quality and amount standard in the Pennsylvania Code at 25 Pa. Code §78.84 and §78.71

Well Logs

After drilling the well but prior to casing and cementing operations, operators must obtain well logs to aid in the geologic, hydrologic, and engineer characterization of the subsurface. Open hole logs, i.e. logs run prior to installing casing and cement, should at a minimum include:

Gamma Ray Logs:

Gamma ray logs detect naturally occurring radiation. These logs are commonly used to determine generic lithology and to correlate subsurface formations. Shale formations have higher proportions of naturally radioactive isotopes than sandstone and carbonate formations. Thus, these formations can be distinguished in the subsurface using gamma ray logs.

Density/Porosity Logs:

Two types of density logs are commonly used: bulk density logs, which are in turn used to calculate density porosity, and neutron porosity logs. While not a direct measure of porosity, these logs can be used to calculate porosity when the formation lithology is known. These logs can be used to determine whether the pore space in the rock is filled with gas or with water.

Resistivity Logs:

These logs are used to measure the electric resistivity, or conversely conductivity, of the formation. Hydrocarbon- and fresh water-bearing formations are resistive, i.e. they cannot carry an electric current. Brine-bearing formations have a low resistivity, i.e. they can carry an electric current. Resistivity logs can therefore be used to help distinguish brine-bearing from hydrocarbon-bearing formations. In combination with Darcy's Law, resistivity logs can be used to calculate water saturation.

Caliper Logs:

Caliper logs are used to determine the diameter and shape of the wellbore. These are crucial in determining the volume of cement that must be used to ensure proper cement placement.

These four logs, run in combination, make up one of the most commonly used logging suites. Additional logs may be desirable to further characterize the formation, including but not limited to Photoelectric Effect, Sonic, Temperature, Spontaneous Potential, Formation Micro-Imaging (FMI), Borehole Seismic, and Nuclear Magnetic Resonance (NMR). The use of these and other logs should be tailored to site-specific needs. (For further reading see, e.g., Asquith and Krygowski, 2004)

UIC Class II rules have specific logging requirements "(f)or surface casing intended to protect underground sources of drinking water in areas where the lithology has not been determined" [40 CFR §146.22(f)(2)(i)]. For such wells, electric and caliper logs must be run before surface casing is installed [40 CFR §146.22(f)(2)(i)(A)]. Such logs should be run on all wells, not just those where lithology has not been determined, and the electric logs suite should include, at a minimum, caliper, resistivity and gamma ray or spontaneous potential logs. For intermediate and long string casing "intended to facilitate injection," UIC Class II rules require that electric porosity, gamma ray, and fracture finder logs be run

before casing is installed [40 CFR §146.22(f)(2)(ii)(A) and (B)]. Hydraulic fracturing should be included in the definition of "injection." Operators should also run caliper and resistivity logs. The term "fracture finder logs" refers to out-dated technology. More advanced tools for locating fractures should be used, such as borehole imaging logs (e.g. FMI logs) and borehole seismic.

Core and Fluid Sampling

While not specifically required by current UIC Class II regulations, operators of wells that will be hydraulically fractured using diesel should also obtain whole or sidewall cores of the producing and confining zone(s) and formation fluid samples from the producing zone(s). At a minimum, routine core analysis should be performed on core samples representative of the range of lithology and facies present in the producing and confining zone(s). Special Core Analysis (SCAL) should also be considered, particularly for samples of the confining zone, where detailed knowledge of rock mechanical properties is necessary to determine whether the confining zone can prevent or arrest the propagation of fractures. Operators should also record the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the producing and confining zone(s). Operators should prepare and submit a detailed report on the physical and chemical characteristics of the producing and confining zone(s) and formation fluids that integrates data obtained from well logs, cores, and fluid samples. This must include the fracture pressure of both the producing and confining zone(s).

WHAT WELL OPERATION, MECHANICAL INTEGRITY, MONITORING, AND REPORTING REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

Mechanical Integrity

Operators must maintain mechanical integrity of wells at all times. Mechanical integrity should be periodically tested by means of a pressure test with liquid or gas, a tracer survey such as oxygen activation logging or radioactive tracers, a temperature or noise log, and a casing inspection log. The frequency of such testing should be based on site and operation specific requirements and be delineated in a testing and monitoring plan prepared, submitted, and implemented by the operator.

Mechanical integrity and annular pressure should be monitored over the life of the well. Instances of sustained casing pressure can indicate potential mechanical integrity issues. The annulus between the production casing and tubing (if used) should be continually monitored. Continuous monitoring allows problems to be identified quickly so repairs may be made in a timely manner, reducing the risk that a wellbore problem will result in contamination of USDWs.

Operations and Monitoring

Each hydraulic fracturing treatment must be modeled using a 3D geologic and reservoir model, as described in the Area of Review requirements, prior to operation to ensure that the treatment will not endanger USDWs. Prior to performing a hydraulic fracturing treatment, operators should perform a pressure fall-off or pump test, injectivity tests, and/or a mini-frac. Data obtained from such tests can be used to refine the hydraulic fracture model, design, and implementation.

The hydraulic fracturing operation must be carefully and continuously monitored. In API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, the

America Petroleum Institute recommends continuous monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate.

If at any point during the hydraulic fracturing operation the monitored parameters indicate a loss of mechanical integrity or if injection pressure exceeds the fracture pressure of the confining zone(s), the operation must immediately cease. If either occurs, the operator must notify the regulator within 24 hours and must take all necessary steps to determine the presence or absence of a leak or migration pathways to USDWs. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the regulator and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids to USDWs has not been compromised. If a loss of mechanical integrity is discovered or if the integrity of the confining zone has been compromised, operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released into a USDW or any unauthorized zone, operators must notify the regulator within 24 hours, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the regulator. If such contamination occurs in a USDW that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publically accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.

Techniques to measure actual fracture growth should be used, including downhole tiltmeters and microseismic monitoring. These techniques can provide both real-time data and, after data processing and interpretation, can be used in post-fracture analysis to inform fracture models and refine hydraulic fracture design. Tiltmeters measure small changes in inclination and provide a measure of rock deformation. Microseismic monitoring uses highly sensitive seismic receivers to measure the very low energy seismic activity generated by hydraulic fracturing (For further reading see, e.g., House, 1987; Maxwell et al., 2002; Le Calvez et al., 2007; Du et al., 2008; Warpinski et al., 2008; Warpinski, 2009; and Cipolla et al. 2011).

Hydraulic fracturing fluid and proppant can sometimes be preferentially taken up by certain intervals or perforations. Tracer surveys and temperature logs can be used to help determine which intervals were treated. Tracers can be either chemical or radioactive and are injected during the hydraulic fracturing operation. After hydraulic fracturing is completed, tools are inserted into the well that can detect the tracer(s). Temperature logs record the differences in temperature between zones that received fracturing fluid, which is injected at ambient surface air temperature, and in-situ formation temperatures, which can be in the hundreds of degrees Fahrenheit.

Operators should develop, submit, and implement a long-term groundwater quality monitoring program. Dedicated water quality monitoring wells should be used to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells. Baseline monitoring should begin at least a full year prior to any activity, with monthly or quarterly sampling to

characterize seasonal variations in water chemistry. Monitoring should continue a minimum of 5 years prior to plugging and abandonment.

Reporting

At a minimum, operators must report:

- All instances of hydraulic fracturing injection pressure exceeding operating parameters as specified in the permit
- All instances of an indication of loss of mechanical integrity
- Any failure to maintain mechanical integrity
- The results of:
    - Continuous monitoring during hydraulic fracturing operations
    - Techniques used to measure actual fracture growth
    - Any mechanical integrity tests
- The detection of the presence of contaminants pursuant to the groundwater quality monitoring program
- Indications that injected fluids or displaced formation fluids may pose a danger to USDWs
- All spills and leaks
- Any non-compliance with a permit condition

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:

1. Baseline water quality analyses for all USDWs within the area of review
2. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
3. Proposed chemical additives (including proppant coating), reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:

1. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
2. Actual chemical additives used, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
3. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

Emergency and Remedial Response

Operators must develop, submit, and implement an emergency response and remedial action plan. The plan must describe the actions the operator will take in response to any emergency that may endanger

human life or the environment – including USDWs – such as blowouts, fires, explosions, or leaks and spills of toxic or hazardous chemicals. The plan must include an evaluation of the ability of local resources to respond to such emergencies and, if found insufficient, how emergency response personnel and equipment will be supplemented. Operators should detail what steps they will take to respond to cases of suspected or known water contamination, including notification of users of the water source. The plan must describe what actions will be taken to replace the water supplies of affected individuals in the case of the contamination of a USDW.

The American Petroleum Institute has published recommended practices for developing a Safety and Environmental Management System (SEMS) plan, API Recommended Practice 75L: Guidance Document for the Development of a Safety and Environmental Management System for Onshore Oil and Natural Gas Production Operation and Associated Activities. This may be a useful document to reference when developing guidance.

WHAT SHOULD THE PERMIT DURATION BE AND HOW SHOULD CLASS II PLUGGING AND ABANDONMENT PROVISIONS BE ADDRESSED FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

The permit should be valid for the life of the well. However, operators must request and receive approval prior to performing any hydraulic fracturing operations that occur subsequent to the initial hydraulic fracturing operation for which the permit was approved. This can be accomplished by means of a sundry or amended permit. Operators must provide updates to all relevant permit application data to the regulator.

Prior to plugging and abandoning a well, operators should determine bottom hole pressure and perform a mechanical integrity test to verify that no remedial action is required. Operators should develop and implement a well plugging plan. The plugging plan should be submitted with the permit application and should include the methods that will be used to determine bottom hole pressure and mechanical integrity; the number and type of plugs that will be used; plug setting depths; the type, grade, and quantity of plugging material that will be used; the method for setting the plugs, and; a complete wellbore diagram showing all casing setting depths and the location of cement and any perforations.

Plugging procedures must ensure that hydrocarbons and fluids will not migrate between zones, into USDWs, or to the surface. A cement plug should be placed at the surface casing shoe and extend at least 100 feet above and below the shoe. All hydrocarbon-bearing zones should be permanently sealed with a plug that extends at least 100 feet above and below the top and base of all hydrocarbon-bearing zones. Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe. In the case of an open hole completion, any hydrocarbon- or fluid-bearing zones shall be isolated by cement plugs set at the top and bottom of such formations, and that extend at least 100 feet above the top and 100 feet below the bottom of the formation.

At least 60-days prior to plugging, operators must submit a notice of intent to plug and abandon. If any changes have been made to the previously approved plugging plan the operator must also submit a revised plugging plan. No later than 60-days after a plugging operation has been completed, operators

must submit a plugging report, certified by the operator and person who performed the plugging operation.

After plugging and abandonment, operators must continue to conduct monitoring and provide financial assurance for an adequate time period, as determined by the regulator, that takes into account site-specific characteristics including but not limited to:

- The results of hydrologic and reservoir modeling that assess the potential for movement of contaminants into USDWs over long time scales.
- Models and data that assess the potential degradation of well components (e.g. casing, cement) over time and implications for mechanical integrity and risks to USDWs.

WHAT SHOULD THE TIME FRAME BE FOR SUBMITTING A PERMIT FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

All operators who wish to drill a Class II well using diesel fuel for hydraulic fracturing must submit a permit application to the regulator. Permit applications should be submitted within a reasonable timeframe but no less than 30 days prior to when the operator intends to begin construction. Under no circumstances shall activity commence until the application is approved and a permit is issued.

WHAT ARE IMPORTANT SITING CONSIDERATIONS?

Site Characterization & Planning

Detailed site characterization and planning and baseline testing prior to any oil and gas development are crucial. Site characterization and planning must take into account cumulative impacts over the life of a project or field.

Operators must submit to the regulator a statistically significant sample, as determined by the regulator, of existing and/or new geochemical analyses of each of the following, within the area of review:

1. Any and all sources of water that serve as USDWs in order to characterize baseline water quality. This data must be made publically available through an online, geographically-based reporting system. The sampling methodology must be based on local and regional hydrologic characteristics such as rates of precipitation and recharge and seasonal fluctuations. At a minimum, characterization must include:
    a. Standard water quality and geochemistry[7]
    b. Stable isotopes
    c. Dissolved gases
    d. Hydrocarbon concentration and composition. If hydrocarbons are present in sufficient quantities for analysis, isotopic composition must be determined

[7] Including: Turbidity, Specific Conductance, Total Solids, Total Dissolved Solids, pH, Dissolved Oxygen, Redox State, Alkalinity, Calcium, Magnesium, Sodium, Potassium, Sulfate, Chloride, Fluoride, Bromide, Silica, Nitrite, Nitrate + Nitrite, Ammonia, Phosphorous, Total Organic Carbon, Aluminum, Antimony, Arsenic, Barium, Beryllium, Boron, Bromide, Cadmium, Chromium, Cobalt, Copper, Cyanide, Iron, Lead, Manganese, Mercury, Molybdenum, Nickel, Selenium, Silver, Strontium, Thallium, Thorium, Uranium, Vanadium, Zinc, Cryptosporidium, Giardia, Plate Count, Legionella, Total Coliforms, and Organic Chemicals including Volatile Organic Compounds (VOCs)

    e. Chemical compounds or constituents thereof, or reaction products that may be introduced by the drilling or hydraulic fracturing process. The use of appropriate marker chemicals is permissible provided that the operator can show scientific justification for the choice of marker(s).

  Operators should also consider testing for environmental tracers to determine groundwater age.

2. Any hydrocarbons that may be encountered both vertically and areally throughout the area of review;
3. The producing zone(s) and confining zone(s) and any other intervening zones as determined by the regulator. At a minimum, characterization must include:
    a. Mineralogy
    b. Petrology
    c. Major and trace element bulk geochemistry

Operators of wells that will be hydraulically fractured must demonstrate to the satisfaction of the regulator that the wells will be sited in a location that is geologically suitable. In order to allow the regulator to determine suitability, the owner or operator must provide:

1. A detailed analysis of regional and local geologic stratigraphy and structure including, at a minimum, lithology, geologic facies, faults, fractures, stress regimes, seismicity, and rock mechanical properties.
2. A detailed analysis of regional and local hydrology including, at a minimum, hydrologic flow and transport data and modeling and aquifer hydrodynamics; properties of the producing and confining zone(s); groundwater levels for relevant formations; discharge points, including springs, seeps, streams, and wetlands; recharge rates and primary zones, and; water balance for the area including estimates of recharge, discharge, and pumping
3. A detailed analysis of the cumulative impacts of hydraulic fracturing on the geology of producing and confining zone(s) over the life of the project. This must include, but is not limited to, analyses of changes to conductivity, porosity, and permeability; geochemistry; rock mechanical properties; hydrologic flow; and fracture mechanics.
4. A determination that the geology of the area can be described confidently and that the fate and transport of injected fluids and displaced formation fluids can be accurately predicted through the use of models.

Wells that will be hydraulically fractured must be sited such that a suitable confining zone is present. The operator must demonstrate to the satisfaction of the regulator that the confining zone:

1. Is of sufficient areal extent to prevent the movement of fluids to USDWs, based on the projected lateral extent of hydraulically induced fractures, injected hydraulic fracturing fluids, and displaced formation fluids over the life of the project;
2. Is sufficiently impermeable to prevent the vertical migration of injected hydraulic fracturing fluids or displaced formation fluids over the life of the project;
3. Is free of transmissive faults or fractures that could allow the movement of injected hydraulic fracturing fluids or displaced formation fluids to USDWs; and

4. Contains at least one formation of sufficient thickness and with lithologic and stress characteristics capable of preventing or arresting vertical propagation of fractures.
5. The regulator may require operators of wells that will be hydraulically fractured to identify and characterize additional zones that will impede or contain vertical fluid movement.

The site characterization and planning data listed above does not have to be submitted with each individual well application as long as such data is kept on file with the appropriate regulator and the well for which a permit is being sought falls within the designated area of review.

WHAT SUGGESTIONS DO YOU HAVE FOR REVIEWING THE AREA AROUND THE WELL TO ENSURE THERE ARE NO CONDUITS FOR FLUID MIGRATION, SEISMICITY, ETC.?

The area of review should be the region around a well or group of wells that will be hydraulically fractured where USDWs may be endangered. It should be delineated based on 3D geologic and reservoir modeling that accounts for the physical and chemical extent of hydraulically induced fractures, injected hydraulic fracturing fluids and proppant, and displaced formation fluids and must be based on the life of the project. The physical extent would be defined by the modeled length and height of the fractures, horizontal and vertical penetration of hydraulic fracturing fluids and proppant, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time.

The model must take into account all relevant geologic and engineering information including but not limited to:

1. Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated hydraulic fracturing pressures, rates, and volumes.
2. Geologic and engineering heterogeneities
3. Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations.
4. Cumulative impacts over the life of the project.

As actual data and measurements become available, the model must be updated and history matched. Operators must develop, submit, and implement a plan to delineate the area of review. The plan should include the time frame under which the delineation will be reevaluated, including those operational or monitoring conditions that would trigger such a reevaluation.

Within the area of review, operators must identify all wells that penetrate the producing and confining zones and provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require. If any the wells identified are improperly constructed, completed, plugged, or abandoned, corrective action must be taken to ensure that they will not become conduits for injected or formation fluids to USDWs. Operators must develop, submit, and implement a corrective action plan.

WHAT INFORMATION SHOULD BE SUBMITTED WITH THE PERMIT APPLICATION?

In addition to the requirements at 40 CFR §146.24, operators should also submit the following information:

1. Information on the geologic structure, stratigraphy, and hydrogeologic properties of the proposed producing formation(s) and confining zone(s), consistent with Site Characterization and Planning requirements, including:
    a. Maps and cross-sections of the area of review
    b. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not provide migration pathways for injected fluids or displaced formation fluids to USDWs
    c. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the producing and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions
    d. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the producing and confining zone(s)
    e. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not affect the integrity of the confining zone(s)
    f. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area
    g. Hydrologic flow and transport data and modeling
2. A list of all wells within the area of review that penetrate the producing or confining zone and a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require.
3. Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known
4. Baseline geochemical analyses of USDWs, hydrocarbons, and the producing and confining zone, consistent with the requirements for Site Characterization & Planning
5. Proposed area of review and corrective action plan that meet the Area of Review and Corrective Action Plan requirements
6. A demonstration that the operator has met the financial responsibility requirements
7. Proposed pre-hydraulic fracturing formation testing program to analyze the physical and chemical characteristics of the producing and confining zone(s), that meet the Well Log, Core, Fluid Sampling, and Testing requirements
8. Well construction procedures that meet the Well Construction requirements
9. Proposed operating data for the hydraulic fracturing operation:
    a. Operating procedure
    b. Calculated fracture gradient of the producing and confining zone(s)

    c. Maximum pressure, rate, and volume of injected fluids and proppant and demonstration that the proposed hydraulic fracturing operation will not initiate fractures in the confining zone or cause the movement of hydraulic fracturing or formation fluids that endangers a USDW
10. Proposed chemical additives:
    a. Service companies and operators must report all proposed additives by their type (e.g. breaker, corrosion inhibitor, proppant, etc), chemical compound or constituents, and Chemical Abstracts Service (CAS) number
    b. Service companies and operators must report the proposed concentration or rate and volume percentage of all additives
11. Proposed testing and monitoring plan that meets the testing and monitoring plan requirements
12. Proposed well plugging plan that meets the plugging plan requirements
13. Proposed emergency and remedial action plan
14. Prior to granting final approval for a hydraulic fracturing operation, the regulator should consider the following information:
    a. The final area of review based on modeling and using data obtained from the logging, sampling, and testing procedures
    b. Any updates to the determination of geologic suitability of the site and presence of an appropriate confining zone based on data obtained from the logging, sampling, and testing procedures
    c. Information on potential chemical and physical interactions and resulting changes to geologic properties of the producing and confining zone(s) due to hydraulic fractures and the interaction of the formations, formation fluids, and hydraulic fracturing fluids, based on data obtained from the logging, sampling, and testing procedures
    d. The results of the logging, sampling, and testing requirements
    e. Final well construction procedures that meet the well construction requirements
    f. Status of corrective action on the wells in the area of review
    g. A demonstration of mechanical integrity
    h. Any updates to any aspect of the plan resulting from data obtained from the logging, sampling, and testing requirements.

HOW COULD CLASS II FINANCIAL RESPONSIBILITY REQUIREMENTS BE MET FOR WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

Operators must demonstrate and maintain financial responsibility by means of a bond, letter of credit, insurance, escrow account, trust fund, or some combination of these financial mechanisms or any other mechanism approved by the regulator. The financial responsibility mechanism must cover the cost of corrective action, well plugging and abandonment, emergency and remedial response, long term monitoring, and any clean up action that may be necessary as a result of contamination of a USDW.

WHAT PUBLIC NOTIFICATION REQUIREMENTS OR SPECIAL ENVIRONMENTAL JUSTICE CONSIDERATIONS SHOULD BE CONSIDERED FOR AUTHORIZATION OF WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

EPA must ensure that there are opportunities for public involvement and community engagement throughout all steps of the process.

1. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:
    a. Baseline water quality analyses for all USDWs within the area of review
    b. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
    c. Proposed chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives
2. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:
    a. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
    b. Actual chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
    c. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

WHAT ARE EFFICIENT ALTERNATIVES TO AUTHORIZE/PERMIT CLASS II WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

The use of area permits should not be allowed for wells that use diesel fuel for hydraulic fracturing. Each hydraulic fracturing operation is unique and designed for site-and well-specific needs. The fluid volumes required, chemical make-up of hydraulic fracturing fluid, and geology and hydrology of the producing and confining zones can vary from well to well.

In situations where multiple wells will be drilled from the same surface location or pad, it may be permissible to issue a group permit for all such wells. In requesting a group permit, operators must provide the regulator with an analysis demonstrating that the geology, hydrology, and operating parameters of all wells are sufficiently similar such that the issuance of a group permit will not pose increased risks to USDWs as compared to individual permits. If a group permit is approved, operators must still disclose information on injected chemicals for each individual well unless the type and volume of chemicals injected will be identical for each well. Operators must also still provide geochemical analyses of flowback and produced water for each individual well.

Conclusions

Thank you for your consideration of these comments. We are pleased that EPA is undertaking this effort to develop permitting guidance for hydraulic fracturing using diesel fuel. While this guidance is crucial to ensure that no further unpermitted hydraulic fracturing using diesel occurs, we urge EPA to begin the process of drafting new regulation that specifically addresses the unique risks hydraulic fracturing poses to USDWs.

Sincerely,

Briana Mordick
Oil and Gas Science Fellow
Natural Resources Defense Council

Amy Mall
Senior Policy Analyst
Natural Resources Defense Council

Kate Sinding
Senior Attorney
Natural Resources Defense Council

Deborah Goldberg
Managing Attorney, Northeast Office
Earthjustice

Michael Freeman
Staff Attorney, Rocky Mountain Office
Earthjustice

Craig Segall
Project Attorney
Sierra Club Environmental Law Program

Deborah J. Nardone, Director
Natural Gas Reform Campaign
The Sierra Club

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UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 6

Sierra Club, et al., *Comments on New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO,* Docket No. EPA-HQ-OAR-2010-0505 (Nov. 30, 2011)

January 27, 2012

BEFORE THE
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO	))))	**Docket No. EPA-HQ-OAR-2010-0505** *Via regulations.gov and e-mail* *November 30, 2011*

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I. INTRODUCTION

Thank you for accepting these comments on behalf of the Sierra Club, the Center for Biological Diversity, Clean Air Council, the Clean Air Task Force, Earthjustice, Earthworks, the Environmental Defense Fund, the Natural Resources Defense Council, the Network for Oil and Gas Accountability and Protection, the San Juan Citizens Alliance, WildEarth Guardians, the West Virginia Surface Owners' Rights Organization, and the Wyoming Outdoor Council. Collectively, we represent millions of members, including many thousands who live and recreate in areas affected by oil and gas operations. On behalf of our members, we thank EPA for updating and expanding the performance standards for this industry, which is rapidly expanding across the United States.

EPA's proposed New Source Performance Standards (NSPS) for the oil and natural gas industry are a long awaited and much needed update. EPA originally included crude oil and natural gas production on the list of air pollution sources that require a NSPS in

1979.[1] Since then, EPA has only promulgated standards for natural gas processing plants, an extremely limited subset of facilities within the industry.[2] EPA failed to regulate oil and gas facilities that emit substantial amounts of air pollution, such as wells, pipelines, and any compressors, valves or storage tanks not located at processing plants. Since EPA last revised the NSPS for this sector, the growth of hydraulic fracturing and horizontal drilling has led to the unprecedented expansion of the oil and gas industry into new areas. This expansion, along with existing development in established oil and gas producing regions, has substantial negative impacts to public health and the environment.

EPA's proposed NSPS contains some good first steps towards addressing the increasing emissions and air pollution from this industry. In particular, we applaud EPA's decision to expand the NSPS to address hydraulic fracturing at well-sites and to cover additional oil and gas facilities, such as compressors, pneumatic controllers, and storage vessels. However, there is still more to be done to make these standards fully compliant with the rigorous requirements of Section 111 of the Clean Air Act.[3]

In Part I of our comments, we review EPA's basic legal obligations under Section 111 and provide an overview of the expanding oil and gas industry and the need for strong air quality regulations. Building on that foundation, in Part II, we provide a technical review of EPA's proposed standards and compare them to those statutory obligations. We identify important gaps in the standards, such as the failure to regulate air emissions from conventional gas wells (those which do not use hydraulic fracturing) or oil wells of any type.

Parts III, IV, and V of our comments address critical gaps in the proposal. EPA has failed to regulate certain sources of pollution, including offshore facilities, oil- and gas-field heater-treaters, and drilling rigs. EPA also has failed to regulate pollutants emitted by the industry, including methane, particulate matter, hydrogen sulfide, and nitrogen oxides. And EPA has failed to regulate many existing sources of pollution, even though they are responsible for the lion's share of the current emissions. We discuss what the law and the scientific evidence require of EPA in each instance.

In Part VI, we address EPA's enforcement and compliance obligations under the statute, which necessitate important changes to EPA's proposal, including retaining oil and gas sector sources in the Title V program, and eliminating EPA's illegal proposed affirmative defense.

In Part VII, we explain how EPA overestimated the costs of air pollution controls and underestimated the benefits. Part VIII demonstrates that industry growth and rigorous

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[1] 44 Fed. Reg. 49,222 (Aug. 21, 1979), attached hereto as Exhibit 1.
[2] 40 C.F.R. Part 60, Subparts KKK & LLL.
[3] 42 U.S.C. § 7411 *et seq.*

clear air regulations can go hand in hand. In fact, the industry has continued to grow despite regulations of the sort that EPA proposes.

In Part IX, we strongly urge EPA to close as many of the gaps in the proposed rule as possible, without delaying finalization by April 3, 2012, as is legally required. In Part X, we emphasize, however, that to the extent that certain obligations simply cannot be met by that date, EPA may not defer any remaining necessary rulemakings indefinitely. Should any necessary rulemaking activity remain beyond this deadline, EPA must complete it by 2013, rather than allowing its already illegally long failure to fully regulate this major industry to persist. EPA may, under no circumstances, defer rulemaking until its next review, which is not required to occur for another eight years. During any delay, unacceptable air pollution will continue to be caused by the industry's improperly controlled emissions.

Several reports from recognized experts support our positions. They are attached to these comments, and incorporated by reference.
Throughout this report, we make many recommendations, which are intended to bring EPA's proposal into compliance with the Clean Air Act. EPA must respond to each recommendation in full. If it opts not to take a recommendation, EPA must explain its rationale in its response to comments.

A. Legal Overview of Section 111 of the Clean Air Act

Section 111 of the Clean Air Act ("CAA" or "Act") requires EPA to set technology-based standards of performance for industrial sources of air pollution.[4] These federal standards of performance apply to all new and modified sources in a listed source category.[5] Because these standards apply to sources in designated or "listed" industrial categories regardless of the ambient air quality in a particular area, they help to prevent new air pollution problems as well as prevent existing problems from worsening. These goals are particularly important with respect to the oil and gas industry, which is responsible for substantial existing air pollution problems and is rapidly expanding into new areas. [6]

[4] *See* 42 U.S.C. § 7411.
[5] 42 U.S.C. 7411(b)(1)(B), (a)(2).
[6] The emission limits established by the standard must be met by sources within listed categories that commence construction or undergo modification after the date of the *proposal* of such standard. *See* 42 U.S.C. §§ 7411(a)(2) (a "new source" is "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance"). Any new source within a listed category that begins operation or any existing source that receives, or should receive, a permit to undergo a modification under Section 111 after the published date of the proposal for the standard must therefore comply with the standard EPA promulgates in the final rule.

New source performance standards must be promulgated on a rigorous timeline, which EPA failed to meet for this industry. Section 111(b)(1)(A) provides:

> The Administrator *shall*, within 90 days after December 31, 1970, publish (and from time to time thereafter *shall* revise) a list of categories of stationary sources. [Sh]e *shall* include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.[7]

Section 111 further provides that within one year following the listing of each such source category, EPA "*shall* publish proposed regulations, establishing Federal standards of performance."[8] Once EPA establishes the standards of performance, it "*shall*, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards."[9]

EPA first proposed new source performance standards for the oil and natural gas industry in 1985.[10] EPA therefore was required to review and revise its 1985 standards no later than 1993. Air pollution emissions from this sector have grown in the interim, and although available control techniques have markedly improved, they have not been consistently applied, because of the delay in revising the requirements to do so. For that reason, it is essential that EPA comply with section 111's high standards in finalizing this rule, as so many sources have gone uncontrolled for so long. Specifically, EPA's updated "standard of performance" must meet the statutory definition:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[11]

"This section directs EPA to set specific and rigorous limits on the amounts of pollutants that may be emitted from any 'new source' of air pollutants" and "reflect a commitment to requiring the best technology."[12] This "best demonstrated technology" ("BDT") or

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[7] 42 U.S.C. § 7411(b)(1)(A) (emphases added).
[8] *Id.* § 7411(b)(1)(B) (emphasis added).
[9] *Id.* (emphasis added).
[10] *See* 50 Fed. Reg. 26122 (June 24, 1985) (promulgation of VOC NSPS covering leaking components as onshore natural gas processing plants), attached hereto as Exhibit 1; 50 Fed. Reg. 40158 (Oct. 1, 1985) (promulgation of NSPS for SO_2 emissions from natural gas processing plants), attached hereto as Exhibit 2.
[11] 42 U.S.C. § 7411(a)(1).
[12] *ASARCO Inc. v. EPA*, 578 F.2d 319, 322 & 322 n.6 (D.C. Cir. 1978), attached hereto as Exhibit 3.

"best system of emission reduction"("BSER") standard[13] is designed to "enhance air quality and not merely to maintain it" by "forcing all newly constructed or modified [facilities] to employ pollutant control systems" that will reflect the best demonstrated system of reduction."[14]

Section 111 is a technology-forcing program. Congress' intent was "to induce, to stimulate, and to augment the innovative character of industry in reaching for more effective, less costly systems to control air pollution."[15] As such, the courts are clear that the "standards should be stringent in order to force the development of improved technology."[16] As the D.C. Circuit has explained, "[s]ection 111 looks toward what may fairly be projected for the regulated future, rather the state of the art at present, since it is addressed to standards for new plants."[17] The required technology need not "be in actual routine use somewhere"; rather, the "essential question," is "whether the [required] technology would be available for installation in new plants."[18]

Because EPA is to set standards that new sources in the industry can meet in the future,[19] it need not set a standard that can be met by every plant "currently in operation . . . at all times and under all circumstances."[20] In other words,

> An achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.[21]

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[13] EPA refers to the standard as "BSER" in this rulemaking, though BDT is the traditional abbreviation . We do not understand EPA's terminological choice to reflect a change in its interpretation of the statute, but the agency must say so, if it is changing its view. We use the terms interchangeably in these comments, understanding both to require emissions limits meeting the statutory standard at each individual facility covered by the standard.

[14] *ASARCO* at 327; *see also Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 785-86 (D.C. Cir. 1976) (discussing these standards), attached hereto as Exhibit 4.

[15] *Sierra Club v. Costle,* 657 F.2d 298, 347 n.174 (D.C. Cir. 1981) (quoting legislative history), attached hereto as Exhibit 5. *See also ASARCO, Inc. v. EPA,* 578 F.2d 319, 322 & n.6 (D.C. Cir. 1978) (The language of section 111 evinces the Congressional "commitment to requiring the best technology" as "[NSPS] are designed to force new sources to employ the best demonstrated systems of emission reduction.")

[16] *ASARCO* at 325.

[17] *Id.* at 391.

[18] *Id. See also Lignite Energy Council v. U.S. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (Achievability "'looks toward what may be fairly projected for the regulated future, rather that the state of the art at present'", attached hereto as Exhibit 6. (quoting *Portland Cement*, 486 F.2d at 391).

[19] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391-92 (D.C. Cir. 1973), attached hereto as Exhibit 7.

[20] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir. 1973), attached hereto as Exhibit 8.

[21] *Id*. at 433. *See also Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 (D.C. Cir. 1980) (achievability is determined "for the industry as a whole."), attached hereto as Exhibit 9.

Whether a "system of emission reduction" is achievable and has been adequately demonstrated is a question of reasonableness: [22]

> An adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.[23]

While EPA is to consider the costs "of achieving [the] reduction" (along with nonair quality health and environmental impacts and energy requirements) when setting a standard of performance, EPA must not lose sight of the technology forcing nature of section 111.[24] The cost issue before the agency is whether the cost of new source control is "greater than the industry could bear and survive." [25]

Where it is "not feasible to prescribe or enforce a standard of performance," EPA must instead "promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction" which is adequately demonstrated.[26] This authority is limited by the Act, which defines the narrow circumstances in which it is "not feasible" to set a standard of performance, including when EPA determines that "a pollutant or pollutants cannot be emitted through a conveyance" capable of capturing such pollutants or that "the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."[27]

Finally, EPA's standard-setting obligations extend to existing sources of some air pollutants. For air pollutants that are not criteria pollutants listed under section 108 or hazardous air pollutants listed and regulated under 112, EPA must prescribe regulations setting out existing source performance standard requirements, to be adopted and implemented by the states.[28]

B. Overview of the Oil and Gas Industry.

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[22] In determining what technologies are "adequately demonstrated" to form the basis for an "achievable" performance standard for a particular source category, courts have held that EPA's analysis can – indeed should, as appropriate – look beyond facilities within the United States. EPA may base its standards on the application of systems of control that are in use in other countries, as well as looking at technology transfers across industries as the basis for an "achievable" performance standard, "*Lignite Energy Council*, 198 F.3d at 933-34 & n.3.

[23] *Id.*

[24] *Lignite Energy Council*, 198 F.3d at 933 (citing *New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992)).

[25] *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975) ("*Portland Cement II*"), attached hereto as Exhibit 10; *see also Lignite Energy Council*, 198 F.3d at 933 (EPA may exclude emission controls that would impose "exorbitant" economic or environmental costs).

[26] 42 U.S.C. § 7411(h)(1).

[27] *Id.* § 7411(h)(2).

[28] *See* 42 U.S.C. § 7411(d).

1. The oil and gas industry is rapidly expanding

Oil and gas development in the United States is on the rise. In 2009, there were over a million wells producing oil and natural gas nationwide.[29] This includes conventional onshore and offshore oil and gas production as well as unconventional coal bed methane, tight gas, and shale oil and gas production.[30] Although the mix of production from these sources is likely to change, the U.S. Energy Information Administration ("EIA") predicts increases in both domestic crude oil and natural gas production over the near term.[31] The EIA predicts that crude oil development will rise until around 2019 and then fall off slightly, and that there will be substantial increases in overall natural gas production between 2009 and 2035.[32] With respect to natural gas development, the EIA predicts drilling will increase by 190% in shale reservoirs, by 138% in tight sands, and by 61% in coalbed methane reserves.[33]

The dramatic rise in shale development is the result of advances in hydraulic fracturing and horizontal drilling that have allowed the industry to unlock oil and gas trapped in shale formations that was previously inaccessible. Successful shale gas production started in the Barnett Shale of north central Texas in the early years of the past decade.[34] Since then, the growth of shale gas development has been extremely rapid. Natural gas now provides approximately 25% of the domestic energy supply.[35] Although shale gas made up less than 2% of gas production in 2001, it now constitutes around 30%.[36] That trend is expected to continue: the EIA predicts shale gas will be 47% of production by 2035.[37]

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[29] EPA, *Proposed Amendments to Air Regulations for the Oil and Natural Gas Industry, Fact Sheet*, at 2, *available at* http://epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf (hereinafter "EPA Fact Sheet"), attached hereto as Exhibit 11.

[30] EIA, *Annual Energy Outlook 2011*, at 79, 82, *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, attached hereto as Exhibit 12.

[31] EPA, *Regulatory Impact Analys*is ("RIA") at 2-26 to 2-28; *see also* EIA, Annual Energy Outlook 2011, at 79, 82.

[32] RIA at 2-28; *see also* EIA, Annual Energy Outlook 2011, at 79, 82.

[33] RIA at 2-27.

[34] EIA, *Annual Energy Outlook 2011, Prospects for Shale Gas*, *available at* http://www.eia.gov/forecasts/aeo/IF_all.cfm#prospectshale, attached hereto as Exhibit 13; *see also* Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements* (Jan. 26, 2009), *available at* http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf. (hereinafter "Barnett Shale Report"), attached hereto as Exhibit 14.

[35] U.S. Dep't of Energy, Secretary of Energy Advisory Board, *Shale Gas Production Subcommittee 90-Day Report*, at 6 (Aug. 18, 2011). (hereinafter "SEAB Interim 90-Day Report"), *available at* http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf, attached hereto as Exhibit 15.

[36] *Id.*; *see also* U.S. Energy Information Administration (EIA), *Outlook for Natural Gas*, at slide 14 (2010), *available at* http://205.254.135.24/neic/speeches/newell101110.ppt (showing 14-fold increase in shale gas development between 200 and 2010, with sharp increase after 2008), attached hereto as Exhibit 16.

[37] EIA, *Outlook for Natural Gas*, at slide 14; *see also* SEAB 90-Day Report at 6-7.

Shale gas production is expected to increase in almost every region of the country, including the Northeast, Gulf Coast, Midcontinent, Southwest, and Rocky Mountain regions.[38] The increase will be dramatic in the Marcellus shale in Northeast, which has only recently been subject to significant shale gas development. Already, Pennsylvania is experiencing large increases in drilling.[39] Even states with a long-history of oil and gas development, such as Colorado and Wyoming, have experienced and will continue to experience shale gas development in new areas.[40]

Development of shale oil is also on the rise.[41] Since the beginning of 2008, the number of active oil rigs has increased 242%, reaching a 24-year high in October of this year.[42] Much of this increase is attributable to development of shale oil plays, such as the Bakken in North Dakota, that are now accessible because of hydraulic fracturing and horizontal drilling techniques.[43] Although shale oil production was negligible a few years ago, industry estimates that it could reach 2 million barrels per day in the next five years.[44]

2. The oil and gas industry is responsible for substantial amounts of emission and air pollution that is harmful to public health and the environment

Oil and gas development includes numerous stages and facilities, all of which contribute to substantial amounts of air emissions and resultant dangerous air pollution. EPA has defined the "oil and gas sector" for the purposes of this rule to include the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas.[45] As depicted below, the sector includes four stages: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission, and (4) natural gas distribution.[46]

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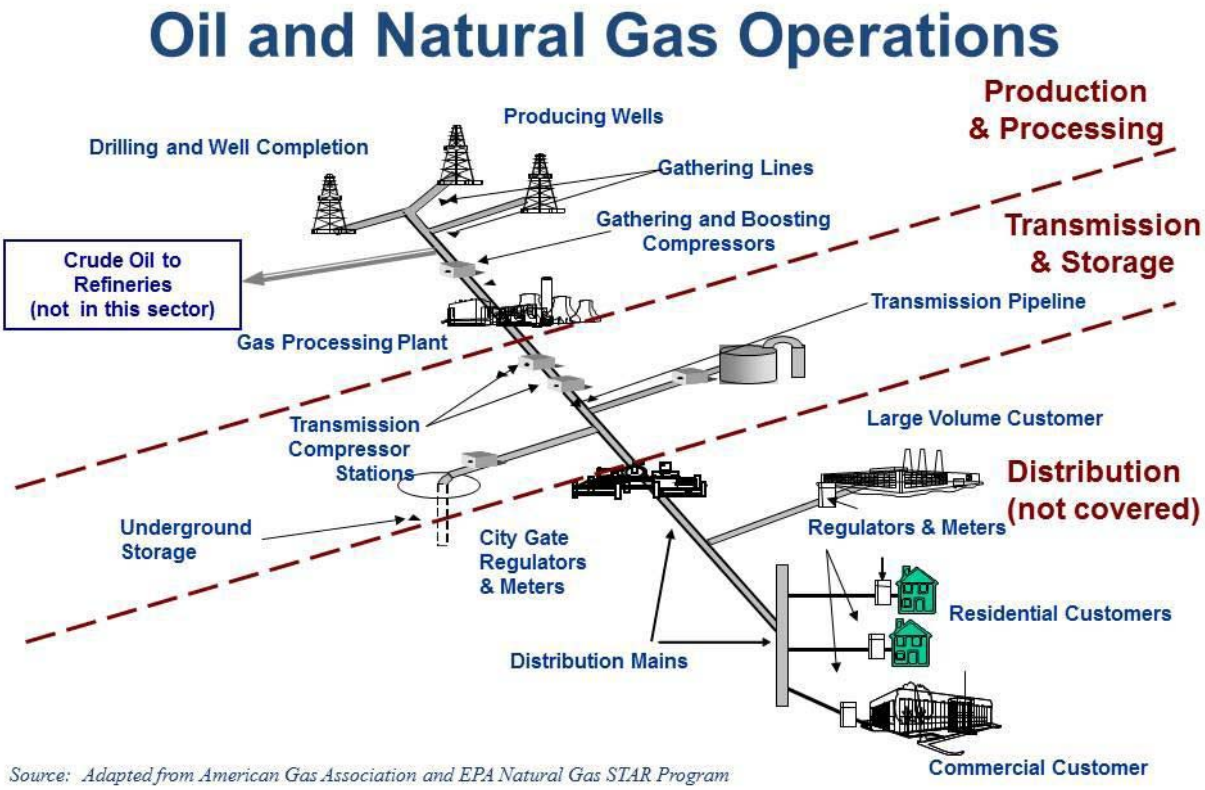
[38] EIA, *Annual Energy Outlook 2011*, at 80.
[39] *SEAB Interim 90-Day Report* at 8.
[40] *Id*.
[41] EIA, *Annual Energy Outlook 2011*, at 82.
[42] *See* Update 2—U.S. Oil Rig Count Hits Record—Baker Hughes, *available at* http://uk.reuters.com/article/2011/10/14/energy-oil-rigs-idUKN1E79D11420111014.http://uk.reuters.com/article/2011/10/14/energy-oil-rigs-idUKN1E79D11420111014, attached hereto as Exhibit 17.
[43] *Id.*
[44] *Id.*
[45] 76 Fed. Reg. 52744. at 52,738, 52,744 (Aug. 23, 2011).
[46] EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document for the Proposed Rules* ("TSD") at 2-4 (July 2011).

Figure 1: The Oil and Natural Gas Sector



Within these development stages, the major sources of air pollution include wells, compressors, pipelines, pneumatic devices, dehydrators, storage tanks, pits and ponds, natural gas processing plants, and trucks and construction equipment. Major air pollutants of concern from these operations include methane (CH_4), volatile organic compounds (VOCs), nitrogen oxides (NO_x), sulfur dioxide (SO_2), hydrogen sulfide (H_2S), and particulate matter (PM_{10} and $PM_{2.5}$). Oil and natural gas operations also emit listed hazardous air pollutants (HAPs), which are regulated separately by National Emissions Standards for Hazardous Air Pollutants (NESHAPs); our comments on the proposed NESHAPs for the oil and gas industries are presented in a separate document.

Methane: Methane is the dominant pollutant from the oil and gas sector. Emissions occur as result of intentional venting or unintentional leaks during drilling, production, processing, transmission and storage, and distribution. For example, methane is emitted when wells are completed and vented, as part of operation of pneumatic devices and compressors, and as a result of leaks (fugitive emissions) in pipelines, valves, and other equipment. EPA has identified natural gas systems as the "single

largest contributor to United States anthropogenic methane emissions."[47] The industry is responsible for over 40% of total U.S. methane emissions, which amounts to 5% of all carbon dioxide equivalent (CO_2e) emissions in the country.[48]

Methane is a potent greenhouse gas that contributes substantially to global climate change. Methane has at least 25 times the global warming potential of carbon dioxide over a 100 year time frame and at least 72 times the global warming potential of carbon dioxide over a 20-year time frame.[49]

Because of methane's effects on climate, EPA has found that methane, along with five other well-mixed greenhouse gases, endanger public health and welfare within the meaning of the Clean Air Act.[50] The impacts of climate change caused by methane and other greenhouse gases include "increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity and sea level rise."[51] A warming climate will also lead to loss of coastal land in densely populated areas, shrinking snowpack in Western states, increased wildfires, and reduced crop yields.[52] More frequent heat waves as a result of global warming have already affected public health, leading to premature deaths. And threats to public health are only expected to increase as global warming intensifies. For example, a warming climate will lead to increased incidence of respiratory and infectious disease, greater air and water pollution, increased malnutrition, and greater casualties from fire, storms, and floods.[53] Vulnerable populations—such as children, the elderly, and those with existing health problems—are the most at risk from these threats.

Methane also reacts in the atmosphere to form ozone.[54] As we discuss below, ozone is a major public health threat, linked to a wide range of maladies. Ozone can also damage vegetation, agricultural productivity, and cultural resources. Ozone is also a

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[47] 76 Fed. Reg. at 52,792.
[48] *Id.* at 52,791–92.
[49] *IPCC 2007—The Physical Science Basis*, Section 2.10.2, attached hereto as Exhibit 18. We note that these global warming potential figures may be revised upward in the next IPCC report. As discussed in the attached report of Dr. Laurie Johnson (See Exhibit 249), discussed below, another more recent study by Shindell *et al.* estimates methane's 100-year GWP at 33; this same source estimates methane's 20-year GWP at 105.
[50] EPA, Endangerment and Cause or Contribute Findings for Greenhouse Gases, 74 Fed. Reg. 66,496, 66,516 (Dec. 15, 2009) ("Endangerment Finding"), attached hereto as Exhibit 19.
[51] 76 Fed. Reg. at 52,791-22 (citing U.S. EPA, 2011 U.S. GREENHOUSE GAS INVENTORY REPORT EXECUTIVE SUMMARY (2011), http://www.epa.gov/climateexchange/emissions/downloads11/US-GHGInventory-2011-ExecutiveSummary.pdf), attached hereto as Exhibit 20.
[52] *Id.* at 66,532–33.
[53] EPA, *Climate Change, Health and Environmental Effects*, *available at* http://epa.gov/climatechange/effects/health.html, attached hereto as Exhibit 21.
[54] 76 Fed. Reg. at 52,791; RIA at 4-27.

significant greenhouse gas in its own right, meaning that methane is doubly damaging to climate – first in its own right, and then as an ozone precursor.

***VOCs and NO_x*:** VOCs and NO_x contribute to the formation of ground-level ozone (also referred to as smog). Smog pollution harms the respiratory system and has been linked to premature death, heart failure, chronic respiratory damage, and premature aging of the lungs.[55] Smog may also exacerbate existing respiratory illnesses, such as asthma and emphysema, or cause chest pain, coughing, throat irritation and congestion. Children, the elderly, and people with existing respiratory conditions are the most at risk from ozone pollution.[56]

Significant ozone pollution also damages plants and ecosystems.[57] Ozone also contributes substantially to global climate change over the short term. According to a recent study by the United Nations Environment Program (UNEP), behind carbon dioxide and methane, ozone is now the third most significant contributor to human-caused climate change.[58]

The oil and gas industry is a major source of the ozone precursors VOCs and NO_x.[59] VOCs are emitted from well drilling and completions, compressors, pneumatic devices, storage tanks, processing plants, and fugitives from production and transmission.[60] The primary sources of NO_x are compressor engines, turbines, and other engines used in drilling and hydraulic fracturing.[61] NO_x is also produced when gas is flared or used for heating.[62]

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[55] RIA at 4-25; Jerrett *et al.*, *Long-Term Ozone Exposure and Mortality*, New England Journal of Medicine (Mar. 12, 2009), *available at* http://www.nejm.org/doi/full/10.1056/NEJMoa0803894#t=articleTop, attached hereto as Exhibit 22.

[56] *See* EPA, *Ground-Level Ozone, Health Effects*, *available at* http://www.epa.gov/glo/health.html attached hereto as Exhibit 23. EPA, Nitrogen Dioxide, Health, available at http://www.epa.gov/air/nitrogenoxides/health.html, attached hereto as Exhibit 24.

[57] RIA at 4-26.

[58] *Id. See also* United Nations Environment Programme and World Meteorological Organization, (2011): *Integrated Assessment of Black Carbon and Tropospheric Ozone: Summary for Decision Makers* (hereinafter "UNEP Report," available at http:// www.unep.org/dewa/Portals/67/pdf/Black_Carbon.pdf), at 7, attached hereto as Exhibit 25.

[59] *See, e.g.,* EPA Fact Sheet at 3; Barnett Shale Report at 24.

[60] *See, e.g.,* TSD at 4-7, 5-6, 6-5, 7-9, 8-1; *see also* Barnett Shale Report at 24.

[61] *See, e.g.,* TSD at 3-6; *See also* Barnett Shale Report at 24. *Air Quality Impact Analysis Technical Support Document for the Revised Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project* at 11 (Table 2.1).

[62] TSD at 3-6; Colorado Department of Public Health and Environment, *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*, Appendix D at 1 (2011), available at http://www.cdphe.state.co.us/ap/RegionalHaze/AppendixD/4-FactorHeaterTreaters07JAN2011FINAL.pdf, attached hereto as Exhibit 26.

As a result of significant VOC and NO_x emissions associated with oil and gas development, numerous areas of the country with heavy concentrations of drilling are now suffering from serious ozone problems. For example, the Dallas Fort Worth area in Texas is home to substantial oil and gas development. Within the Barnett shale region, as of September 2011, there were more than 15,306 gas wells and another 3,212 wells permitted.[63] Of the nine counties surrounding the Dallas Forth Worth area that EPA has designated as "nonattainment" for ozone, five contain significant oil and gas development.[64] A 2009 study found that summertime emissions of smog-forming pollutants from these counties were roughly comparable to emissions from motor vehicles in those areas.[65]

Oil and gas development has also brought serious ozone pollution problems to rural areas, such as western Wyoming.[66] On March 12, 2009, the governor of Wyoming recommended that the state designate Wyoming's Upper Green River Basin as an ozone nonattainment area.[67] The Wyoming Department of Environmental Quality conducted an extended assessment of the ozone pollution problem and found that it was "primarily due to local emissions from oil and gas . . . development activities: drilling, production, storage, transport, and treating."[68] Last winter alone, the residents of Sublette County suffered thirteen days with ozone concentrations considered "unhealthy" under EPA's current air-quality index, including days when the ozone pollution levels exceeded the worst days of smog pollution in Los Angeles.[69] Residents have faced repeated warnings regarding elevated ozone levels and the resulting risks of going outside.[70]

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[63] Texas Railroad Commission, http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf (Accessed Nov. 21, 2011), attached hereto as Exhibit 27.
[64] Barnett Shale Report at 1, 3.
[65] *Id.* at 1, 25-26.
[66] Schnell, R.C, et al. (2009), "Rapid photochemical production of ozone at high concentrations in a rural site during winter," *Nature Geosci.* 2 (120 – 122). DOI: 10.1038/NGEO415, attached hereto as Exhibit 28.
[67] *See* Letter from Wyoming Governor Dave Freudenthal to Carol Rushin, Acting Regional Administrator, USEPA Region 8, (Mar. 12, 2009) ("Wyoming 8-Hour Ozone Designation Recommendations"), *available at* http://deq.state.wy.us/out/downloads/Rushin%20Ozone.pdf, attached hereto as Exhibit 29; Wyoming Department of Environmental Quality, Technical Support Document I for Recommended 8-hour Ozone Designation of the Upper Green River Basin (March 26, 2009) ("Wyoming Nonattainment Analysis"), at vi-viii, 23-26, 94-05, *available at* http://deq.state.wy.us/out/downloads/Ozone%20TSD_final_rev%203-30-09_jl.pdf, attached hereto as Exhibit 30.
[68] Wyoming Nonattainment Analysis at viii.
[69] EPA, *Daily Ozone AQI Levels in 2011 for Sublette County, Wyoming*, *available at* http://www.epa.gov/cgi-bin/broker?msaorcountyName=countycode&msaorcountyValue=56035&poll=44201&county=56035&msa=-1&sy=2011&flag=Y&_debug=2&_service=data&_program=dataprog.trend_tile_dm.sas, attached hereto as Exhibit 31.; *see also* Wendy Koch, *Wyoming's Smog Exceeds Los Angeles' Due to Gas Drilling*, USA Today, *available at* http://content.usatoday.com/communities/greenhouse/post/2011/03/wyomings-smog-exceeds-los-angeles-due-to-gas-drilling/1, attached hereto as Exhibit 32.
[70] *See, e.g., 2011 DEQ Ozone Advisories*, Pinedale Online! (Mar. 17, 2011) (documenting ten ozone advisories in February and March 2011), *available at*

Ozone problems are mounting in other Rocky Mountain states as well. Northeastern Utah recorded unprecedented ozone levels in the Uintah Basin in 2010 and 2011. In the first three months of 2010—which was the first time that winter ozone was monitored in the region—air quality monitors measured more than 68 exceedances of the federal health standard. On three of these days, the levels were almost twice the federal standard.[71] Between January and March 2011, there were 24 days where the National Ambient Air Quality Standard (NAAQS) for ozone were exceeded in the area. Again, ozone pollution levels climbed to nearly twice the federal standard.[72] The Bureau of Land Management (BLM) has identified the multitude of oil and gas wells in the region as the primary cause of the ozone pollution.[73]

Rampant oil and gas development in Colorado and New Mexico is also leading to high levels of VOCs and NO_x. In 2008, the Colorado Department of Public Health and Environment concluded that the smog-forming emissions from oil and gas operations exceed vehicle emissions for the entire state.[74] Moreover, significant additional drilling has occurred since 2008. Colorado is now home to more than 46,000 wells.[75] There is also significant development in the San Juan Basin in southeastern Colorado and northwestern New Mexico, with approximately 35,000 wells in the Basin. As a result of this development and several coal-fired power plants in the vicinity, the Basin suffers

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http://www.pinedaleonline.com/news/2011/03/OzoneCalendar.htm, attached hereto as Exhibit 33; Wyoming Department of Environmental Quality, Ozone Advisory for Monday, Feb. 28, Pinedale Online! (Feb. 27, 2011), *available at* http://www.pinedaleonline.com/news/2011/02/OzoneAdvisoryforMond.htm, attached hereto as Exhibit 34

[71] Scott Streater, *Air Quality Concerns May Dictate Uintah Basin's Natural Gas Drilling Future*, N.Y. TIMES, Oct. 1, 2010, *available at* http://www.nytimes.com/gwire/2010/10/01/01greenwire-air-quality-concerns-may-dictate-uintah-basins-30342.html?pagewanted=1 (last visited Sept. 28, 2011), attached hereto as Exhibit 35.

[72] *See* EPA, AirExplorer, Query Concentrations (Ozone, Uintah County, 2011), available at http://www.epa.gov/cgi-bin/htmSQL/mxplorer/query_daily.hsql?msaorcountyName=countycode&msaorcountyValue=49047&poll=44201&county=49047&site=-1&msa=-1&state=-1&sy=2011&flag=Y&query=download&_debug=2&_service=data&_program=dataprog.query_daily3P_dm.sas, attached hereto as Exhibit 36.

[73] BLM, *GASCO Energy Inc. Uinta Basin Natural Gas Development Draft Environmental Impact State*ment ("GASCO DEIS"), at 3-13, *available at* http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa_/gasco_energy_eis.html, attached hereto as Exhibit 37.

[74] Colo. Dept. of Public Health & Env't, Air Pollution Control Division, Oil and Gas Emission Sources, *Presentation for the Air Quality Control Commission Retreat*, at 3-4 (May 15, 2008), attached hereto as Exhibit 38.

[75] Colorado Oil & Gas Conservation Commission, *Colorado Weekly & Monthly Oil and Gas Statistics*, at 12 (Nov. 7, 2011), available at http://cogcc.state.co.us/ (library—statistics—weekly/monthly well activity), attached hereto as Exhibit 39.

from serious ozone pollution.[76] This pollution is taking a toll on residents of San Juan County. The New Mexico Department of Public Health has documented increased emergency room visits associated with high ozone levels in the County.[77]

Air quality in national parks and wilderness areas is also suffering as a result of oil and gas development. Researchers have determined that numerous "Class I areas" – a designation reserved for national parks, wilderness areas, and other such lands[78] – are likely to be impacted by increased ozone pollution as a result of oil and gas development in the Rocky Mountain region, including Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico.[79] These areas are all near concentrated oil and gas development in the San Juan Basin.[80]

As oil and gas development moves into new areas, particularly as a result of the boom in development of shale resources, ozone problems are likely to follow. For example, regional air quality models predict that gas development in the Haynesville shale will increase ozone pollution in northeast Texas and northwest Louisiana and may lead to violations of ozone NAAQS.[81] Experts also anticipate air quality problems associated with development of the Marcellus shale in the Mid-Atlantic region.[82]

Sulfur dioxide: Sulfur dioxide causes respiratory problems, including increased asthma symptoms. Short-term exposure to sulfur dioxide has been linked to increased emergency room visits and hospital admissions. Sulfur dioxide reacts in the atmosphere to form particulate matter (PM), an air pollutant which causes a great deal of harm to human health.[83] PM is discussed separately below.

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[76] *See Four Corners Air Quality Task Force Report of Mitigation Options*, at vii (Nov. 1, 2007), *available at* http://www.nmenv.state.nm.us/aqb/4C/TaskForceReport.html, attached hereto as Exhibit 40.

[77] Myers *et al.*, *The Association Between Ambient Air Quality Ozone Levels and Medical Visits for Asthma in San Juan County* (Aug. 2007), *available at* http://www.nmenv.state.nm.us/aqb/4c/Documents/SanJuanAsthmaDocBW.pdf, attached hereto as Exhibit 41.

[78] *See* 42 U.S.C. § 7472(a).

[79] Rodriguez et al., *Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States*, 59 Journal of the Air and Waste Management Association 111 (Sept. 2009), available at http://www.wrapair.org/forums/amc/meetings/091111_Nox/Rodriguez_et_al_OandG_Impacts_JAWMA9_09.pdf, attached hereto as Exhibit 42.

[80] *Id.* at 1112.

[81] *See* Kemball-Cook et al., *Ozone Impacts of Natural Gas development in the Haynesville Shale* 44 Environ. Sci. Technol. 9357, 9362 (Nov. 18, 2010), attached hereto as Exhibit 43.

[82] Elizabeth Shogren, *Air Quality Concerns Threaten Natural Gas's Image*, National Public Radio (June 21, 2011), *available at* http://www.npr.org/2011/06/21/137197991/air-quality-concerns-threaten-natural-gas-image, attached hereto as Exhibit 44.

[83] EPA, Sulfur Dioxide, Health, *available at* http://www.epa.gov/air/sulfurdioxide/health.html, attached hereto as Exhibit 45.

The primary source of sulfur dioxide from the oil and gas industry is natural gas processing plants.[84] Sulfur dioxide is released as part of the sweetening process, which removes hydrogen sulfide from the gas.[85] Sulfur dioxide is also created when gas containing hydrogen sulfide (discussed below) is combusted in boilers or heaters.[86]

Hydrogen sulfide: Hydrogen sulfide is an air pollutant with toxic properties that smells like rotten eggs and can lead to neurological impairment or death. Long-term exposure to hydrogen sulfide is linked to respiratory infections, eye, nose, and throat irritation, breathlessness, nausea, dizziness, confusion, and headaches.[87] Although hydrogen sulfide was originally included in the Clean Air Act's list of hazardous air pollutants, it was removed with industry support.[88]

Some natural gas contains hydrogen sulfide. When hydrogen sulfide levels are above a specific threshold, gas is classified as "sour gas."[89] According to EPA, there are 14 major areas in the U.S., found in 20 different states, where natural gas tends to be sour.[90] All told, between 15 and 20% of the natural gas in the U.S. may contain hydrogen sulfide.[91]

Given the large amount of drilling in areas with sour gas, EPA has concluded that the potential for hydrogen sulfide emissions from the oil and gas industry is "significant."[92] Hydrogen sulfide may be emitted during all stages of development, including exploration, extraction, treatment and storage, transportation, and refining.[93] For

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[84] 76 Fed. Reg. at 52,756.
[85] TSD 3-3 to 3-5.
[86] 76 Fed. Reg. at 52,756.
[87] EPA, Office of Air Quality Planning and Standards, *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas* (EPA-453/R-93-045), at i (Oct. 1993) (hereinafter "EPA Hydrogen Sulfide Report"); *available at* http://nepis.epa.gov/Exe/ZyNET.exe/00002WG3.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1991+Thru+1994&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C91thru94%5CTxt%5C00000006%5C00002WG3.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=p%7Cf&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL, attached hereto as Exhibit 46.
[88] *See* Pub. L. 102-187 (Dec. 4, 1991), attached hereto as Exhibit 47. We do not concede that this approval was appropriate. Hydrogen sulfide meets section 112 of the Clean Air Act's standards for listing as a hazardous air pollutant, and should be so regulated. However, until such time as it is reinstated as an HAP, it must be included in the revised NSPS.
[89] 76 Fed. Reg. at 52,756; RIA at 2-3. Gas is considered "sour" of hydrogen sulfide concentration is greater than 0.25 grain per 100 standard cubic feet, along with the presence of carbon dioxide. *Id.*
[90] *EPA Hydrogen Sulfide Report* at ii.
[91] Lana Skrtic, *Hydrogen Sulfide, Oil and Gas, and People's Health* ("Skrtic Report"), at 6 (May 2006), *available at* http://www.earthworksaction.org/pubs/hydrogensulfide_oilgas_health.pdf, attached hereto as Exhibit 48.
[92] *EPA Hydrogen Sulfide R*eport at III-35.
[93] *Id.* at ii.

example, hydrogen sulfide is emitted as a result of leaks from processing systems and from wellheads in sour gas fields.[94]

Hydrogen sulfide emissions from the oil and gas industry are concerning because this pollutant may be harmful even at low concentrations.[95] Although direct monitoring of hydrogen sulfide around oil and gas sources is limited, there is evidence that these emissions may be substantial, and have a serious impact on people's health. For example, North Dakota reported 3,300 violations of an odor-based hydrogen sulfide standard around drilling wells.[96] People in northwest New Mexico and western Colorado living near gas wells have long complained of strong odors, including but not limited to hydrogen sulfide's distinctive rotten egg smell. Residents have also experienced nose, throat and eye irritation, headaches, nose bleeds, and dizziness.[97] An air sample taken by a community monitor at one family's home in western Colorado in January 2011 contained levels of hydrogen sulfide concentrations 185 times higher than safe levels.[98]

Particulate Matter (PM): PM consists of tiny particles of a range of sizes suspended in air. Small particles pose the greatest health risk. These small particles include "inhalable coarse particles," which are smaller than 10 micrometers in diameter (PM_{10}), and "fine particles" which are less than 2.5 micrometers in diameter ($PM_{2.5}$). PM_{10} is primarily formed from crushing, grinding or abrasion of surfaces. $PM_{2.5}$ is primarily formed by incomplete combustion of fuels or through secondary formation in the atmosphere.[99]

PM causes a wide variety of health and environmental impacts. PM has been linked to respiratory and cardiovascular problems, including coughing, painful breathing, aggravated asthma attacks, chronic bronchitis, decreased lung function, heart attacks, and premature death. Sensitive populations, include the elderly, children, and people with existing heart or lung problems, are most at risk from PM pollution.[100] PM also reduces visibility,[101] and may damage important cultural resources.[102] Black carbon, a

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[94] TSD at 2-3.

[95] *See* James Collins & David Lewis, *Report to CARB, Hydrogen Sulfide: Evaluation of Current California Air Quality Standards with Respect to Protections of Children* (Sept. 1, 2000), *available at* http://oehha.ca.gov/air/pdf/oehhah2s.pdf, attached hereto as Exhibit 49.

[96] EPA Hydrogen Sulfide Report at III-35.

[97] *See* Global Community Monitor, *Gassed! Citizen Investigation of Toxic Air Pollution from Natural Gas Development*, at 11-14 (July 2011), attached hereto as Exhibit 50.

[98] *Id.* at 21.

[99] *See* EPA, Particulate Matter, Health, *available at* http://www.epa.gov/pm/health.html, attached hereto as Exhibit 51; BLM, *West Tavaputs Plateau Natural Gas Full Field Development Plan Final Environmental Impact Statement* ("West Tavaputs FEIS"), at 3-19 (July 2010), *available at* http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/wtp_final_eis.html, attached hereto as Exhibit 52.

[100] RIA at 4-19; EPA, Particulate Matter, Health, *available at* http://www.epa.gov/pm/health.html

[101] EPA "Visibility – Basic Information" http://www.epa.gov/visibility/what.html, attached hereto as Exhibit 53.

[102] *See* EPA, Particulate Matter, Health West Tavaputs EIS, at 3-19; RIA at 4-24.

component of PM emitted by combustion sources such as flares and older diesel engines, also warms the climate and thus contributes to climate change.[103]

The oil and gas industry is a major source of PM pollution. This pollution is generated by heavy equipment used to move and level earth during well pad and road construction. Vehicles also generate fugitive dust by traveling on access roads during drilling, completion, and production activities.[104] Diesel engines used in drilling rigs and at compressor stations are also large sources of fine PM/diesel soot emissions. VOCs are also a precursor to formation of $PM_{2.5}$.[105]

PM emissions from the oil and gas industry are leading to significant pollution problems. For example, monitors in Uintah County and Duchesne County, Utah have repeatedly measured wintertime $PM_{2.5}$ concentrations above federal standards.[106] These elevated levels of $PM_{2.}$ have been linked to oil and gas activities in the Uinta Basin.[107] West Tavaputs FEIS at 3-20. Modeling also shows that road traffic associated with energy development is pushing PM_{10} levels very close to violating NAAQS standards.[108]

3. EPA must revise and expand the existing performance standards to curb this pollution

The current NSPS is inadequate and outdated. In 1985, EPA promulgated two separate NSPS for the "crude oil and natural gas production" sector.[109] The first NSPS addresses leaks of VOCs from onshore natural gas processing plants.[110] The second regulates sulfur dioxide emissions from natural gas processing plants.[111] The two standards only address emissions from natural gas processing plants, leaving the majority of emissions from the oil and gas industry unregulated at the federal level.

As we discuss above, EPA is required under Section 111 of the Clean Air Act to "review and, if appropriate, revise" NSPS standards every 8 years.[112] Although more than 25 years have passed since EPA promulgated the NSPS for the oil and natural gas sector, EPA has not reviewed or updated the standard until now.

Not only are the existing performance standards for this industry inadequate, but existing state regulations do not fill the gaps. As we describe below, some states do

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[103] UNEP Report at 6; IPCC (2007) at Section 2.4.4.3.
[104] *See* BLM, GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental Impact Statement, at App. J at 2 (Oct. 2010) ("GASCO DEIS")
[105] RIA at 4-18.
[106] GASCO DEIS at 3-12.
[107] West Tavaputs FEIS, at 3-20 (July 2010).
[108] *See* GASCO DEIS at 4-27.
[109] 76 Fed. Reg. at 52,741.
[110] 40 C.F.R. Part 60, Subpart KKK.
[111] 40 C.F.R. Part 60, Subpart LLL.
[112] 42 U.S.C. § 7411(b)(1)(B).

regulate this industry with some rigor (indeed, in a few cases, state rules are more rigorous than EPA's proposed standards), but these regulations are not uniform across the states, nor comprehensive. Eastern states, newly contending with the shale gas boom, are particularly in need of the federal baseline the NSPS must provide, as most of these states do not have adequate air quality rules specific to oil and gas production. Pennsylvania, for instance, does not have regulations that would require reduced emission completions, even though wellhead emissions are primary pollution sources for the industry. To our knowledge, other Marcellus Shale states, including Ohio, New York, and West Virginia likewise lack comprehensive modern air rules to regulate the industry's air quality impacts. EPA rulemaking is thus urgently needed.

Moreover, as EPA's proposed rule demonstrates, there are numerous cost-effective control technologies available to control emissions from this sector, that can and must form the basis for updated performance standards.

II. TECHNICAL REVIEW OF EPA's PROPOSED STANDARDS

As we discuss below, the record before EPA demonstrates that EPA must maintain the stringency of its proposed standards, and in some respects must strengthen them, to comply with the Clean Air Act's rigorous requirements. The proposed standards are based upon practices that are already widespread in the industry, and generally save the industry money by allowing it to capture additional valuable natural gas. By requiring existing industry best practices for many sources, and codifying those practices into law, EPA does not always meet the Act's requirement to force additional control technology innovation. Indeed, the Agency is in several instances not even providing incentives for the development of new control techniques but instead merely bases standards on long-demonstrated and cost-effective systems of emission reduction. For that reason, the proposed standards are in some cases more technology-following than technology-forcing, and are thus unlawfully lenient.

The agency therefore must correct several significant weaknesses in the rules. These flaws fall into several categories. In some instances, the proposed standards are vague and/or unclear. In others, the agency has created unnecessarily broad exemptions to its standards which will allow operators to escape compliance, or which will cause enforcement difficulties. In some other instances, EPA has set standards below the levels which industry can achieve, and must therefore tighten its control standards. Finally, EPA has simply failed to set standards for some sources and facility types at all.

Our review below relies in part on several reports by well-recognized experts, which we incorporate in full by reference. These experts include Dr. Ranajit Sahu, whose report focuses on the engineering data underlying EPA's proposal, Cindy Copeland and Megan Williams, whose report addresses methane and VOC control technologies, Dr. Laurie

Johnson, whose report concerns issues of methane valuation,[113] and Rick Hornby and Dr. Carl Swanson, whose report concerns natural gas pricing.

A. Wellhead Facilities

1. EPA's Proposal

EPA proposes to regulate "gas wellhead facilities," each of which would constitute a "single natural gas well."[114] EPA determined that it was not feasible to set a standard of performance for this category because some pollutants would be emitted in a mixture of water and sand, apparently in ways that would render them impossible to properly channel or measure, *cf.* 42 U.S.C. § 7411(h)(2). It therefore promulgated operational standards, pursuant to section 111(h).[115]

These standards would require, for "each well completion operation with hydraulic fracturing," that the operator conduct "reduced emission" or "green" completions, under which the owner or operator is required to "minimize the emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system."[116] Operators would have to use sand traps, vessels, tanks, and separators to "safely maximize resource recovery and minimize releases to the environment" and route all salable gas to a gathering line "as soon as practicable." *Id.* Flowback emissions would be sent to a gathering line "except in conditions that may result in a fire hazard or explosion."[117] Where such conditions exist, operators are to use "[c]ompletion combustion devices . . . equipped with a reliable continuous ignition source."[118]

Two types of wells, "wildcat" and "delineation" wells, may avoid using gathering lines and instead "reduce emissions . . . using a completion combustion device."[119] A wildcat well is "a well outside known fields or the first well drilled in an oil or gas field where no other gas or oil production exists."[120] A delineation well is "a well drilled in order to determine the boundary of a field or producing reservoir."[121]

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[113] Dr. Laurie Johnson, Ph.D, "Comments on The Social Benefits of Methane Reductions from the Proposed Oil and Gas New Source Performance Standards," *Natural Resources Defense Council*, November 17, 2011, attached hereto as Exhibit 249.
[114] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. § 60.5365(a)). Proposed 40 C.F.R. § 60.5365(a) is missing a "which" in the sentence explaining that a gas wellhead facility is a single natural gas well. EPA must correct this error.
[115] *See* 76 Fed. Reg. at 52,758-59.
[116] 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5375(a)).
[117] *Id.*
[118] *Id.*
[119] *Id.* (Proposed 40 C.F.R. § 60.5375(f)).
[120] *Id*. at 52,811 (Proposed 40 C.F.R. § 60.5430).
[121] *Id.* at 52,809.

2. BTSER Determination

a. New Wellhead Facilities

We agree with EPA that some form of reduced emissions completion (REC) constitutes the "best technological system of continuous emission reduction" (BTSER) which has been adequately demonstrated for wellhead facilities,[122] and that emissions standards based on these practices would "reflect the best system of emission reduction . . . adequately demonstrated."[123] We emphatically do not agree, however, that EPA has, in fact, drafted regulations compliant with the BTSER standard. As we discuss below, EPA's proposed regulations have such significant flaws—including impermissible exemptions – that they will not be compliant with section 111 without significant revision.

As the Sahu and Copeland and Williams reports discuss, the record amply supports the broad utility and cost-effectiveness of REC techniques.[124] Furthermore, as EPA explains in the Technical Support Document for this rulemaking (TSD), REC "not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented."[125] EPA estimates that an average green completion results in net *savings* of $5,697 and yield 20.8 tons of avoided VOC emissions per well.[126] In fact, the savings will be even higher because, as we discuss below,[127] EPA underestimated the direct financial benefits of RECs by using an unrealistically low gas price and potentially overstating REC costs.

In light of the practice's financial benefits, industry has widely adopted REC, and several states currently require REC. Colorado, for instance requires "green completion practices" wherever technically and economically feasible,[128] and Wyoming requires green completions in its Jonah Anticline fields and all "Areas of Concentrated Development."[129] According to EPA, "RECs have become a popular practice among Natural Gas STAR production partners," with, as of 2010, thirteen different partners

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[122] *See* 76 Fed. Reg. at 52,758-59, 42 U.S.C. § 7411(h)(1)
[123] 42 U.S.C. § 7411(a)(1).
[124] Cindy Copeland and Megan Williams, *Methane Related Comments on EPA's "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," Proposed Rule* (November 29, 2011*)* attached hereto as Exhibit 54; Dr. Ranajit Sahu, *Comments on EPA Proposed NSPS Rulemaking for Crude Oil and Natural Gas Production, Transmission, and Distribution* (Nov. 2011)at 9-11, attached hereto as Exhibit 55.
[125] TSD at 4-12.
[126] TSD at 4-16 – 4-18.
[127] *See infra* Section VII.
[128] Co. Oil & Gas Conserv. Comm'n ("COGCC") Rule 805(b)(3)(A), attached hereto as Exhibit 56.
[129] Wy. Oil and Gas Production Facilities Permitting Guidance ("Wy. Guidance") at 15, 20, attached hereto as Exhibit 57.

reporting success.[130] EPA Natural Gas Star partners have reported considerable success with REC in a variety of geographical contexts, including:

- BP's implementation of RECs on 106 wells, at both high and low pressures, in the Green River Basin of Wyoming, which resulted in a "conservative" value of gas saved at $20,000 per well.[131]

- Noble Experience's implementation of REC on 10 hydrofractured wells in Oklahoma, with profits of $340,000.[132]

- An anonymous partner company's implementation of REC on 30 wells in Fort Worth, Texas, which resulted in a "conservative" savings of $50,000 per well.[133]

- Anadarko's implementation of REC in the Denver-Julesberg Basin of Wyoming, saving an average of $19,369 per well.[134]

- Chesapeake and Devon's extensive use of green completions in the Barnett Shale (these companies are the two largest producers in the Barnett Shale), constituting 114 of every 115 wells, and 85% of wells, respectively.[135]

We discuss further examples of profitable RECs in our cost discussion below,[136] and industry and EPA literature is replete with examples of successful RECs.[137]

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[130] EPA, *Reduced Emissions Completions: Lessons Learned from Natural Gas STAR Partners* at 1 (2010), available at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf, attached hereto as Exhibit 58. *See also* EPA, *Reducing Methane Emissions During Completion Operations* (Oct. 24, 2006), attached hereto as Exhibit 59.
[131] *Id.* at 10.
[132] *Id.*
[133] *Id.* at 10.
[134] Anadarko, *Reduced Emission Completions in DJ Basin and Natural Buttes*, EPA Producers Technology Transfer Workshop (May 1, 2008), attached hereto as Exhibit 60.
[135] April 18, 2011 presentation to the Oil and Gas Task Force of the North Texas Clean Air Steering Committee; available at http://www.nctcog.org/trans/committees/ntcasc/OGTF/041811/Items3BC.pdf, attached hereto as Exhibit 61.
[136] *See infra* Section VII(B)(2)(a).
[137] *See, e.g.*, Methane to Markets, Oil & Gas Subcommittee Technology Transfer Workshop, *Reduced Emission Completions/Plunger Lift and Smart Automation* (Jan. 28, 2009) (collecting examples of profitable RECs), attached hereto as Exhibit 62; EPA, PRO Fact Sheet 703, *Green Completions* (documenting use of RECs by BP & ConocoPhilips), attached hereto as Exhibit 63; EPA, Natural Gas STAR Lessons Learned, *Reduced Emissions Completions* (endorsing RECs as a profitable and effective control technique); John Corra, Director, Wyoming Department of Environmental Quality, *Emissions from Hydrofracking Operations and General Oversight Information for Wyoming* (July 13, 2011) (describing successful implementation of state-level REC requirement), attached hereto as Exhibit 64; Chesapeake Energy, *Air Emissions and Regulations*(July 2011) (stating that Chesapeake uses green completions at its wells), attached hereto as Exhibit 65;Chesapeake Energy, *Greenhouse Gas Emissions* (last visited Nov. 2011) (stating that "green completions . . . have been Chesapeake's largest contributor of emissions

In short, RECs generate profits, reduce emissions, and allow for more salable gas and condensate. RECs therefore are the *minimum* requirement for BTSER for new and modified wells. No lesser requirement would be compliant with section 111. Yet, in several regards, EPA has failed to impose this level of control, as we will shortly discuss.

b. Modifications

We also support EPA's recognition that recompletions of fractured or refractured wells drilled prior to August 23, 2011 constitute modification under section 111(a). These activities are a very large source of emissions, and their control under the proposed standards of performance is a key component of EPA's proposal. There is a definitional flaw in EPA's proposed language, however, which we discuss below.

Under part 60, subpart OOOO, 40 C.F.R. § 60.5430, EPA sets forth the following regarding modifications in the oil and gas sector:

> any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. *For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification*.[138]

This provision, to the extent that it defines hydraulic fracturing operations as modifications, is in keeping with section 111's definition of modification. But EPA must modify it in two regards. First, it must make pellucidly clear that EPA intends to override any conflicting regulatory definitions of modification. Second, it must revise the definition to remove undefined terms.

First, The Clean Air Act defines "modification" under section 111 as "*any* physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."[139] As EPA points out, during the fracturing or refracturing of an existing well, "physical change occurs to the existing well, which includes the wellbore, casing and tubing, resulting in an emissions increase during the

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reductions), attached hereto as Exhibit 66; EnCana, *Environment Health and Safety Commitment* (describing EnCana's efforts to reduce flaring and venting at its wells), attached hereto as Exhibit 67.

[138] 76 Fed. Reg. at 52,810 (emphasis added).

[139] 42 U.S.C. § 7411(a)(4) (emphasis added); *see also* 40 C.F.R. § 60.14(a) ("any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act.").

completion operation."[140] For purposes of NSPS, an emissions increase occurs whenever emissions after a physical change are greater than emissions immediately prior to the change.[141]

Not only do hydraulic fracturing activities meet the statutory definition of modification, but EPA's proposal in proposed 40 C.F.R. § 60.5430 that recompletions of these wells are modifications for the purposes of this industry overrides any conflicting provisions in the general NSPS definition of modification contained in 40 C.F.R. § 60.14.[142] Thus, to the extent that any of the exemptions contained in 60.14(c) would otherwise prevent recompletions and refracturing from being considered modifications, they would be overridden by the specific oil and gas provision.

While the proposed 60.5430 is sufficient to override any conflicting portions of 60.14,[143] we encourage EPA to clarify the regulatory language by explicitly invoking § 60.14(f) and explaining that the capital expenditure test codified at 40 C.F.R. § 60.14(e)(2), for example, does not apply.[144]

Second, EPA is wrong to define a modification in this context as "each recompletion of a fractured or refractured existing gas well" because "recompletion" is an undefined term and so will lead to confusion. The relevant modification – and source of increased emissions – in this context is, in fact, the hydraulic fracturing operation at the well. EPA must simply say so.

So the revised section 60.5430 would read:

> *Modification* means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. *For the purposes of this subpart, each hydraulic fracturing operation at an existing gas well is considered to be a modification regardless of any provision of 40 C.F.R. § 60.14(e) stating regulatory exemptions to the term "modification*.

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[140] 76 Fed. Reg. at 52,759; *see also* TSD at 4-1 – 4-2.

[141] *Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901, 910, 915 (7th Cir. 1990) (citing CAA § 111(a) and 40 C.F.R. § 60.14(b)(2)), attached hereto as Exhibit 68.

[142] *See id*. § 60.14(f). EPA previously has relied on 60.14(f) to depart from its general regulatory definition of modification by delineating what constitutes a modification under a sector-specific subpart of the NSPS "to eliminate ambiguity." *See* 73 Fed. Reg. 35838, 38856 (June 24, 2008) (defining what constitutes a flare modification for Petroleum Refineries, subpart Ja), (codified at 40 C.F.R. § 60.100a(c) (2010)).

[143] We do not concede that EPA' regulatorily-created "exemptions" from the statute's broad modification definition are legal.

[144] *See also* 40 C.F.R. § 60.2 (defining "capital expenditure").

3. Further Critiques

We support EPA's proposal to require "reduced emission" or "green" completions. Nonetheless, there are three general areas in which the proposal must be strengthened. EPA must at a minimum (1) clarify and strengthen the language of the proposed standard; (2) extend the REC requirement to many well types that are currently excluded from the proposed standard; and (3) enhance standards for pit flaring.

a. Definitional Issues

The proposed regulation uses a number of undefined or poorly defined terms. As a result of the needlessly complicated wording, the proposed regulatory text fails in three regards. It fails to clearly and inclusively define hydraulically fracturing. It fails to clearly apply EPA's standards to fractured and refractured existing wells. And it fails to articulate comprehensible and enforceable standards. EPA must correct these failings. As EPA has explained in the context of permit requirements, source obligations must be practically enforceable, and language that is vague, ambiguous, or otherwise unclear creates lack of clarity as to legal obligations. The same concern obviously attaches to the underlying regulations as well.

First, EPA's core "hydraulic fracturing" definition must be revised. EPA's proposal defines the process as:

> The process of directing pressurized liquids, containing water, proppant, and any added chemicals, to penetrate tight sand, shale, or coal formations that involve high rate, extended back flow to expel fracture fluids and sand during completions and well workovers.[145]

The definition is unclear, which will lead to enforcement problems, and may also be underinclusive. EPA must revise it.

The lack of clarity arises in two ways. First, EPA defines fracturing as involving a "high" rate of "extended" back flow. These are relative terms, and are not defined in the text. Operators and enforcement staff are highly likely to differ over what constitutes high or extended flows.

The second clarity problem arises because the definition states that the process takes place by directing chemicals "to penetrate [various formations] that involve high rate, extended back flow *to expel fracture fluids and sand during completions and well workovers*." By focusing on the *purpose* of the activity, rather than its effects, EPA has inadvertently left room for debate as to whether a given well operation is intended "to penetrate" formations or has some other goal. Worse, the proposed text muddles the

[145] 76 Fed. Reg. at 52,810. (Proposed 40 C.F.R. § 60.5430).

purpose at issue, as it refers both to processes intended "to penetrate" formations and "to expel fracture fluids and sand during completions and well workovers." This second "purpose" is not a goal of fracturing operations, because backflow is not intended to do anything in particular; it is a *consequence* of pressure in the well itself caused by the fracturing process (which itself is not intended "to expel fracture fluids and sand").

EPA can, and must, resolve all of these problems by revising the definition to avoid discussions of the magnitude of backflow and the purpose of the operation. It can do so because all hydraulic fracturing, as far as we are able to determine, involves perforating the casing of the well with explosive charges to allow fracturing fluids to enter a formation. EPA can therefore use the moment of casing perforation as the trigger point for NSPS applicability.

The underinclusivity problem, next, arises because fracturing may not always be conducted with water. Fracturing using foams,[146] gases, [147] or hydrocarbons[148,149] is also possible, and foam fracturing is used in U.S. plays. Although these methods may result in less immediate flowback, they may still generate significant produced water, which is a source of VOCs and methane, and may also result in increased emissions, relative to conventional wells, during the hydraulic fracturing process. EPA must investigate whether emissions from these processes are significant. If so, it must modify its definition to refer to these processes as well, or, to encompass other potential processes, could also refer simply to "pressurized substances," which "may" include water.

The fully corrected definition would, in other words, read:

> The process of directing pressurized substances, which may contain foam, gases, water, hydrocarbons, proppant, and any added chemicals, into a well whose casing is perforated, allowing these substances to leave the well bore.

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[146] *See, e.g.*, EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (2004) at 4-5 – 4-6 (discussing these foam gels), attached hereto as Exhibit 69; Ken Little, Knoxville News, "Nitrogen-heavy gas drilling method common in Tenn." (Dec. 5, 2010), available at http://www.knoxnews.com/news/2010/dec/05/nitrogen-heavy-method-prevalent-in-tenn/?print=1, attached hereto as Exhibit 248.

[147] 76 Fed. Reg. at 52,757.

[148] *See, e.g.*, Hans. D. Linhardt, "LNG and LIN can be Alternative Fracturing Methods for Shale Gas" (Dec. 18, 2009), available at https://www.gplus.com/natural-resources/insight/lng-and-lin-can-be-alternative-fracturing-methods-for-shale-gas-45488, attached hereto as Exhibit 70.

[149] *See, e.g.*, Anna Driver, Reuters, "Propane Substitutes for water in shale fracking" (Nov. 22, 2011), available at http://www.reuters.com/article/2011/11/22/us-shale-propane-idUSTRE7AL1ML20111122, attached hereto as Exhibit 71.

Second, as we have indicated above, EPA's proposed language does not effectuate its intent to apply its standards to "completions associated with fracturing or re-fracturing of existing gas wells."[150]

We have already explained why EPA's definition of "modification" must be revised to refer simply to "hydraulic fracturing operations" at existing wells. EPA must also address a second definitional problem, which is that its proposed applicability language for its REC standard would attach that requirement to "each well completion operation with hydraulic fracturing."[151] This language does not clearly refer to fracturing and refracturing at *existing wells*. Stepping through the definitions, a "well completion operation means any well completion or well workover occurring at a gas wellhead affected facility."[152] A well "completion," next, is defined with reference to "newly drilled" wells, so EPA must have intended the "workover" term to encompass refracturing as a modification at existing wells. Indeed, the only explicit discussion of well modifications in the proposed regulation is the statement that a "workover" is a modification. [153] But the workover term itself is not defined, and is vague.[154] The result is that EPA has not clearly applied REC requirements to fracturing and refracturing at existing wells. [155]

A far simpler and more effective solution, which we urge EPA to adopt, is to amend proposed 40 C.F.R. § 60.5375 to impose REC and associated requirements on each "well completion, and any other hydraulic fracturing operation," using the fracturing of the well casing itself as the trigger point to apply standards, and as the indicator that a "modification" has occurred. With this definitional change, coupled with the revisions to the modification section we discuss above (which would make clear that each fracturing event is a modification), such operations at existing wells will be covered by the standards, as they must be.

Third, the proposed standard itself is dangerously unclear. EPA's proposed standard requires operators to "minimize" emissions by storing and then routing to pipelines as much recovered liquid and gas as possible, with the backstop of flaring or venting the remaining emissions, and to "minimize" releases to the environment.[156] But it does not define what "minimize" means, or how EPA will know when an operator is not "minimizing" in accordance with the standard. Likewise, though EPA provides that

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[150] 76 Fed. Reg. at 52,745-46.
[151] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. §60.5375).
[152] 76 Fed. Reg. at 52,809 (Proposed 40 C.F.R. § 60.5430).
[153] As we discuss above, EPA should clarify that by refracturing, recompletion or workover is a modification pursuant to CAA § 111(a) *per se*, such that the capital expenditure test adopted by EPA at 40 C.F.R. § 60.14(e)(2) does not apply. *See also* § 60.2 (defining "capital expenditure"), § 60.14(f) (EPA may adopt "special provisions" under part 60 that supercede the general provisions of § 60.14).
[154]
[155] We note that EPA's "hydraulic fracturing" definition also uses the undefined "workover" term. EPA must strike that term there as well, if it does not define it.
[156] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5375(a)).

resource recovery is to be "safely maximize[d]," it does not define that term either. Nor does EPA set any limit on how much gas may be flared, rather than captured, stating only that gas which "cannot be directed" to a gathering line is to be sent to flares. Similarly, salable gas is to be routed to a gathering line as "soon as practicable," a term that leaves considerable room for dispute. EPA must tighten these definitional holes.

EPA must resolve these problems by stating clearly that, except in the very narrow defined circumstances where safety considerations so warrant, *all* emissions from the wellhead must be either captured or flared, not vented, and that flaring is a disfavored secondary option, to be used only when it is not possible to capture the wellhead emissions for safety reasons. In doing so, EPA must avoid the use of the "maximize" and "minimize" terms which will otherwise cause substantial difficulties.

It must do so by revising proposed 40 C.F.R. § 60.5375(a) to read as follows, in pertinent part[157]:

> … (1) You must capture all gases and liquids emanating from each well subject to these regulations at all times following perforation of the well casing until flowback has ceased.
>
> (2) You must route all recovered liquids into storage vessels and route all recovered gas into a gas gathering line or collection system, except as specified in paragraph (a)(3).
>
> (3) Where direction of recovered gases or liquids into storage vessels or gas gathering lines is not possible due to material safety hazards, you must direct these materials to a completion combustion device, except in conditions that pose a material risk of fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

EPA must also add a requirement that operators record a specific reason for flaring or venting in lieu of capture, to the record-keeping requirements in the proposed rule, and provide advance notice of flaring or venting to permitting authorities where feasible.[158]

Finally, EPA must clarify the proposed regulation to reflect EPA's intention as stated in the preamble that the Administrator must be notified *before* well completions occur. The preamble states that "the proposed NSPS requires 30-day *advance* notification of each completion or recompletion of a hydraulically fractured gas well."[159] The proposed regulation, however, merely states that an operator must "notif[y] the Administrator within 30 days of the commencement of the well completion operation."[160] Read

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[157] We recommend putting paragraph (a)(2) in the proposal before paragraph (a)(1), and have done so here, because (a)(2) describes how operators must recover the "recovered liquids" and "recovered gas" referred to in (a)(1).

[158] *See* 76 Fed. Reg. at 52,808 (Proposed 40 C.F.R. § 60.5420(c)(1)(iii)(A)).

[159] *Id.* at 52,749.

[160] *Id.* at 52,805 (Proposed 60 C.F.R. § 60.5410(a)(1)).

literally, the proposed regulation would be satisfied so long as the Administrator was notified no later than 30 days *after* the completion. EPA further requests comment regarding a two day follow-up notification.[161] We agree that if the 30-day advance notification does not commit the operator to a precise date for completion, once the date is determined, then follow-up notification (at least two days prior to commencement of completion operations) must be required, to allow for on-site inspection.

b. Exclusions

EPA has improperly excluded several classes of wells that can contribute to harmful levels of air pollution.

First, EPA proposes to exempt "wildcat" and "delineation" wells from the REC requirements (but not from the flaring standards) even when they are hydraulically fractured high flowback gas wells in tight sand or shale formations. The proposed regulations define a "wildcat well" as "a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists."[162] A "delineation well" is "a well drilled in order to determine the boundary of a field or producing reservoir."[163] EPA asserts without support that "[b]ecause these types of wells generally are not in proximity to existing gathering lines, REC is not an option, since there is no infrastructure in place to get the recovered gas to market or further processing."[164]

EPA does not support its conclusion and the exemptions unnecessarily and impermissibly allows excess emissions. Moreover, the exclusion invites enforcement difficulties, as operators and enforcement staff may dispute whether a well fits into either category, as the precise boundaries of a field – and the purpose for which a well is drilled – may be unclear.

To avoid these difficulties, and to extend the REC standards to as many wells as possible, EPA must eliminate its "delineation" well exemption, and sharply narrow its "wildcat" well exemption.

The "delineation" well concept is readily subject to misuse, as it turns on both the operators intent (e.g., was the well drilled "to determine" a boundary?), and upon the "boundary of a field or producing reservoir," which is a difficult and subjective line to draw. In a sense, each well drilled in a given field helps define that field's boundaries and extent, opening this exemption to confusion and gamesmanship. EPA must eliminate it.

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[161] *Id.* at 52,749.
[162] *Id.* at 52,811 (Proposed 40 C.F.R. § 60.5430).
[163] *Id.* at 52,809.
[164] 76 Fed. Reg. at 52,759.

In doing so, EPA will be following the lead of the state of Wyoming, which has determined that, in areas covered by its green completion requirements, "lack of a pipeline connection due to reasons other than wildcat, exploratory or step-out well classification" does not excuse avoiding an REC.[165] Wyoming, in other words, lacks a "delineation" well exemption – the wells which it exempts are all in remote, undeveloped areas, unlike "delineation" wells, which are drilled in existing fields.[166] Remoteness is the hallmark. As EPA's own TSD explains:

> The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).[167]

EPA must follow suit. The goal must be to define a narrow, easily-recognized category of exempt wells which truly cannot construct or access a gathering line, a subset which is likely quite narrow because, as EPA acknowledges, "[i]n instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC."[168]

We urge EPA, therefore, to define wildcat well narrowly, and ensure that only wildcat wells which cannot access a gathering line receive an exemption. To do so, it must first narrow its wildcat well definition, which as proposed applies to "a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists."[169] Because multiple wells may be drilled "outside known fields," and companies can and should plan to capture emissions from later wells, EPA must narrow this exemption to mean "the *first* well *drilled* outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists."

Next, EPA must make clear, in Proposed 40 C.F.R. § 60.5375, that these wildcat wells can only be exempted from an REC if they are, in fact, not near a gathering line. EPA must set a reasonable distance from a gathering line below which even wildcat wells will be required to conduct an REC.

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[165] Wyoming Department of Environmental Protection, Green Completion Permit, available at: http://deq.state.wy.us/aqd/Oil%20and%20Gas/AQD-OG11_Green%20Completion%20Application.pdf, attached hereto as Exhibit 72.

[166] Wyoming, for instance, defines "wildcat" wells as "wells outside known fields or new wells which are determined by the Commission to have discovered oil or gas in a pool not previously proven productive." Wy. Oil & Gas Conserv. Comm'n Rule 1 §2(iii)., attached hereto as Exhibit 73.

[167] TSD at 4-14.

[168] *Id.*

[169] 76 Fed. Reg. at 52,809 (Proposed 40 C.F.R. § 60.5430).

EPA must consider three miles as such a reasonable distance. A typical Marcellus well, for instance, costs $3 million to drill,[170] while the costs of building a three-mile long gathering line to that well are far less, and, if the well is productive, eclipsed by the revenues the well produces.[171] If EPA deems this distance is not reasonable, it must explain why not, and propose an alternative distance.

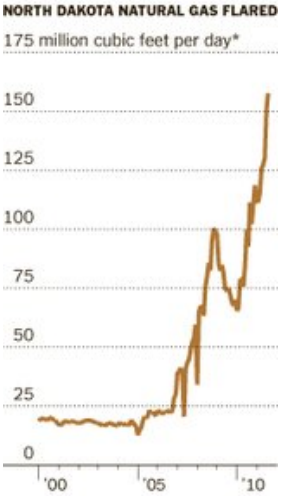
Finally, we urge EPA to collect the information necessary to determine whether all wells, including wildcat wells, can use gas that would otherwise be flared as fuel for onsite operations, and the emissions consequences of such a diversion. If onsite fuel use produces more limited secondary environmental impacts than flaring, it must be required, where possible, and may be an especially attractive option for wells that are not near a gathering line.

Second, EPA needs to include hydraulically fractured oil wells that produced associated gas in its standards. These wells are excluded under the proposed standard, which applies only to gas wells.[172] EPA acknowledges that hydraulic fracturing at oil wells creates a period of flowback with increased natural gas and VOC emissions.[173]

EPA must require that the maximum amount of gas produced from hydraulically fractured oil wells during both flowback and normal production, be captured rather than vented or flared. Recent developments raise questions about EPA's estimates of low emissions from these wells. Specifically, the *New York Times* reports that very large amounts of gas are being flared daily in the hydraulically fractured Bakken Shale play in North Dakota. The *Times* reports gas discharges of over 150 million cubic feet per day being flared in that field, as **Figure 2**, on the right of this page, indicates.[174] This huge volume of flaring is undoubtedly producing significant air pollution, and is avoidable with RECs and connection to gas gathering lines.

Flared Natural Gas

In North Dakota, much of the natural gas incidentally uncovered in the course of oil production is "flared," or burned off, and in effect, wasted. The amount of natural gas flared has risen sharply in the state.



*The difference between natural gas produced and that sold is used to represent the amount flared, although a small amount of the gas may be used in internal plant operations.

Source: North Dakota Industrial Commission, Dept. of Mineral Resources, Oil and Gas Division

This report, drawn from North Dakota government data, very strongly argues that REC, and continuing gas capture from

[170] PennState Live, *Unconventional natural gas reservoir could boost US supply* (Nov. 2008), available at http://live.psu.edu/story/28116, attached hereto as Exhibit 74.
[171] *See, e.g.*, Interstate Natural Gas Association of America, *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030* (2009) (offering pipeline cost figures) at 48, attached hereto as Exhibit 75.
[172] 76 Fed. Reg. at 52,757.
[173] 76 Fed. Reg. at 52,757, TSD §§ 4.1.1 – 4.1.2.
[174] *See* Clifford Kraus, *New York Times*, "In North Dakota, Flames of Wasted Gas Light the Prairie" (Sept. 28, 2011), attached hereto as Exhibit 76.

producing oil wells, would be economically and environmentally beneficial.[175] Although producers may have to focus on expanding gathering line construction to prevent this waste, other options, including reinjection, must be explored. EPA must drive the process with a strong performance standard for such wells. As a start, EPA must require the productive capture and routing to a pipeline of vented associated gas at oil wells whenever natural gas gathering pipelines are within a reasonable distance (three miles, as we explain above) to an affected oil well. If reinjection, productive use onsite, or capture for sale of gas cannot be required, then EPA must ensure that emissions from flares are minimized.

Third, EPA is apparently considering exempting some coalbed methane wells from its REC requirement. EPA is concerned that low pressure in some coalbed methane reservoirs may present a technical barrier for performing a REC.[176] We have not found data in the record regarding the pressure in coalbed methane formations or demonstrating that these pressures render RECs infeasible. Indeed, BP has been using green completions in coalbed methane formations in the San Juan Basin for at least seven years.[177] Because RECs are possible in coalbed methane, EPA must not exempt coalbed methane wells from the NSPS's REC requirements.[178]

If EPA does, however, opt for an exemption in this area, it must ensure that the exemption is keyed specifically to the feasibility of conducting an REC at a specific coalbed methane well, and is not a blanket exemption for all such wells. Any exemption must be subject to public notice and comment.

Fourth, we are concerned that EPA has proposed no controls for other well-related activities. Liquids unloading and other well cleanup activities are dominant methane emissions sources, according to EPA's most recent greenhouse gas inventory.[179] Because VOCs are generally co-emitted with methane at natural gas production wells, we expect these activities to be significant VOC sources as well. Cost-effective technologies, including plunger lifts, are available to control these VOC emissions, and investments in such measures can be recouped within a year.[180] Yet, EPA has proposed no standards requiring these effective and widely-used measures. This decision is not consistent with EPA's obligations under section 111, as it fails to impose standards based upon an available and widely-demonstrated technology that could significantly reduce sector VOC emissions. It is our understanding that EPA believes technologies like

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[175] *See* Copeland and Williams Report at 18-20 (documenting these emissions).
[176] *See* 76 Fed. Reg. at 52,758.
[177] *See* Sahu Report at 12.
[178] *See also* Copeland and Williams Report at 15-16 (describing REC performed in Texas, Wyoming, and Colorado at low pressure well sites).
[179] US EPA (2011), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, tables A-120 (pp. A-149 – A-153), attached hereto as Exhibit 77.
[180] *See, e.g.* Sahu Report at 8, Copeland and Williams Report at 17-18.

plunger lifts are already in use at many facilities, and even a cursory investigation demonstrates that plunger lifts are, indeed, popular emissions control technology.[181]

Thus, BTSER controls must be based, at a minimum, upon plunger lifts. We note that EPA originally appears to have intended to require such activities, as "plunger lift system" is defined in the definitions section of the rule.[182] EPA must follow through. EPA must require that new wells drilled be equipped with plunger lifts or similar technology to reduce VOC emissions if they fill up with liquids. Furthermore, liquids unloading, a physical change to a gas well which substantially increases emissions of VOC from the well, must be treated as a modification of that well. This treatment is consistent with, and mandated by, EPA's recognition, in the context of hydraulic fracturing context, that such physical changes are modifications. Precisely the same legal logic applies here. EPA must therefore clarify its modification definition to include liquids unloading events, and develop standards to cover these events which, as we have demonstrated, must be based upon plunger lift technology, at a minimum.

c. Managing Flaring

EPA must also strengthen its flaring requirement. The proposed standard would channel emissions which it is not feasible to capture to a "completion combustion device, except in conditions that may result in a fire hazard or explosion."[183] These combustion devices "must be equipped with a reliable continuous ignition source over the duration of the flowback."[184] This standard is a useful start, but it does not minimize emissions risks.

First, as described above, EPA must tighten the requirements to capture gas, so it is not flared (or vented). As part of this tightening, EPA must require that operators document the reason that capture does not occur and venting *or flaring* occurs.

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[181] *See, e.g.*, Methane to Markets, Oil & Gas Subcommittee Technology Transfer Workshop, *Reduced Emission Completions/Plunger Lift and Smart Automation* (Jan. 28, 2009) (describing successful plunger lift projects); INGAA Foundation, *Activities to Reduce Greenhouse Gas Emissions from Natural Gas Operations* (2000) at 33 (recommending plunger lifts),attached hereto as Exhibit 78; BP, *Plunger Well Vent Reduction Project* (2006) (describing "great success" with plunger lifts), attached hereto as Exhibit 79; IPS, *Plunger Lifts* (last visited Nov. 2011) (vendor offering plunger lifts), attached hereto as Exhibit 80; Lufkin International Lift Systems, *Plunger Lift Systems* (last visited Nov. 2011) (vendor offering plunger lift systems, attached hereto as Exhibit 81;Weatherford, *Plunger Lift System Overview* (last visited Nov. 2011) (vendor offering plunger lifts), attached hereto as Exhibit 82; Production Lift Systems, Inc, *Plunger Lift Principles* (last visited Nov. 2011) (vendor offering plunger lifts), attached hereto as Exhibit 83

[182] 76 Fed. Reg. at 52,810 (Proposed 40 C.F.R. § 60.5430).

[183] 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5375(a)(3)).

[184] *Id.*

Second, EPA must tighten its venting exemption, which allows operators to avoid venting in conditions "that may result in a fire hazard or explosion." Safety is certainly an important consideration, but this language is vague – many conditions "may" have some degree of hazard, especially when dealing with inherently flammable gas. To avoid this problem, while retaining legitimate safety precautions, EPA must revise this passage to require combustion except in conditions "that pose a material risk of fire hazard or explosion" or similar.[185]

Third, EPA must enhance flaring requirements. The proposal allows use of a "completion combustion device," defined as "any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions or workovers."[186] EPA acknowledges that such devices will result in increased NO_x, carbon monoxide (CO) and PM emissions.[187] To our knowledge, there are no published studies on the emissions of pit flares consuming raw natural gas under field conditions. Such studies exist for refinery flares, but they may not be applicable due to the much more narrow operating conditions as opposed to pit flares. In the absence of appropriate studies, anecdotal evidence suggests that pit flares can emit significant amounts of NO_x, CO, PM (including black carbon), VOC, and methane as a result of incomplete combustion and other by-products of combustion as a whole. EPA must issue an information collection request under section 114 of the Act to gather data on this dangerous class of flares, and must also conduct field studies or sponsor field measurements of emissions from pit flares as operated in the oil and gas industry in order to quantify the public health and welfare impacts from this type of flaring.

EPA acknowledges that in practice, combustion at the wellhead is "rather crude, consisting of a horizontal pipe . . . fitted with a continuous ignition source and discharging over a pit near the wellhead."[188] This is because the flowback stream includes "periods of water, condensate and gas" that cannot be directly routed to a traditional control device.[189] EPA must minimize the use of these inefficient and polluting pit flares.

To reduce these pollutants, the proposal must require use of enclosed combustion devices where possible. In an enclosed combustion device, the flame is enclosed in a box at ground level and thus is not affected by the wind, resulting in higher combustion efficiency. An enclosed flare has many advantages including nonstructural support (ground level), straightforward erection, easy maintenance, negligible operating costs,

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[185] We have incorporated this language into our suggested revisions to Proposed 40 C.F.R. § 60.5375, above.
[186] 76 Fed. Reg. at 52, 809 (Proposed 40 C.F.R. § 60.5430).
[187] *See* 76 Fed. Reg. at 52,758; TSD at 4-20.
[188] 76 Fed. Reg. at 52,757-58.
[189] *Id.*

invisible flame, and low noise emission. The disadvantage is that they require considerable space and long interconnecting piping.

EPA also must consider the feasibility of requiring use of separators, dehydrators, and related equipment to render this stream suitable for less crude flaring devices with better pollution control characteristics.[190, 191] Such modifications would allow EPA to apply the flaring efficiency standards of 40 C.F.R. § 60.18 to field flaring operations. Although we understand that EPA is concerned that these standards may be difficult to apply to field flares as written,[192] the 98%-99% control efficiencies of well-managed flares,[193] are very likely significantly superior to the current performance of pit flares. Indeed, EPA's own methane emissions guidance documents discuss pipe flaring at well sites with 99% control efficiencies achieved through proper engineering.[194] By adding requirements to separate and dehydrate "multiphase slug flow," EPA can require well-managed flares.[195] It must do so.

B. Pneumatic Controllers

1. EPA's Proposal

EPA proposes to treat each pneumatic controller as an affected facility for NSPS purposes.[196] A "pneumatic controller" is "an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature."[197]

The proposed standard generally requires that each pneumatic controller at a natural gas processing plant "must have zero emissions of natural gas" while all other controllers "must have natural gas emissions of no greater than 6 standard cubic feet per hour."[198] There is an important exemption to this requirement. If an operator can demonstrate that "the use of a high bleed device is predicated," they will be exempt from the standards.[199] The proposal does not define "predicated."

2. BSER Determination

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[190] Sahu Report at 11-12.

[191] By adding these requirements to § 60.5375(a)(3), they would apply both to residual gas that could not be routed to a gathering line despite a REC and also in situations where a REC was infeasible.

[192] *See* TSD at 4-19.

[193] *See* Copeland & Williams Report at 21-22.

[194] EPA-600/R-96-080f, GRI-94/0257.23 June 1996 "Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary," p. 24, attached hereto as Exhibit 84.

[195] *See* 76 Fed. Reg. at 52,759; Copeland & Williams Report at 21-22.

[196] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. § 60.5365).

[197] *Id*. at 52,810 (Proposed 40 C.F.R. § 60.5430).

[198] Proposed 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390).

[199] *Id*.

We generally agree with EPA that no-bleed and (where necessary) low-bleed controllers constitute BSER for this facility type. The TSD compellingly demonstrates that controllers are a major emission source, and that the cost of control for these emissions is reasonable.[200] VOC emissions from a single high-bleed controller in the production sector reach 1.92 tons per year,[201] and thousands of controllers are installed annually.[202] The incremental cost of a low-bleed controller is just $165,[203] and no-bleed instrument-air systems are also manageably inexpensive.[204] According to EPA, low-bleed controllers in the production sector alone would *save* the industry over $20 million in the first year the rule becomes effective, with increasing savings in subsequent years.[205]

We strongly support the use of this effective, inexpensive, and profitable control technology as the basis for EPA's standards.[206] However, as we discuss below, EPA's proposed regulations do not implement the statute's requirements appropriately, setting illegally high emissions limits and allowing broad exemptions from the rules. Unless EPA corrects this error, its standards will not comply with section 111's mandates.

EPA did, however, properly include each pneumatic device in the proposed NSPS as an affected facility.[207] EPA also correctly concluded that each installation of a new pneumatic device is construction subject to the NSPS.[208] This conclusion is necessary and appropriate from a policy standpoint, and fully supported as a legal matter.

EPA regulations focus on the practical ability to apply control technology to a pollution source, defining "affected facility" as "any apparatus to which a standard is applicable."[209] EPA correctly notes that a pneumatic device is an "apparatus."[210] It is also clear that each installation of a new replacement pneumatic device is construction subject to the NSPS. The regulations define "construction" as "fabrication, erection or installation of an affected facility."[211]

Furthermore, these facilities are significant sources of emissions nationwide. As EPA stated in the TSD:

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[200] *See* TSD at Ch. 5.
[201] *Id.* at 5-6
[202] *Id.* at 5-8
[203] *Id.* at 5-15
[204] *See id.* at 5-25
[205] *Id.* at 5-25.
[206] *See also* Sahu Report at 15-18 (detailing emissions rates); Copeland & Williams Report at 32-34. (documenting emissions reductions).
[207] *See* 76 Fed. Reg. at, 52,761.
[208] *Id*.
[209] 40 CFR. § 60.2.
[210] *See* 76 Fed. Reg. at 52,761.
[211] 40 CFR § 60.2 (2010).

> In the production segment, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. There are around 13,000 gas pneumatic controllers located in the gathering, boosting and processing segment that control and monitor temperature, liquid, and pressure levels. In the transmission segment, an estimated 85,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.[212]

EPA estimates that a total of 17,124 new pneumatic devices will be installed each year emitting roughly 32,747 tpy of VOCs, 118,054 tpy of methane and 1,237 tpy of HAPs.[213]

It is important to note that the above figures for pneumatic devices represent only new incremental installations of that equipment. Although the proposed regulation will require that pneumatic devices installed after August 23, 2011 *as replacements of existing equipment* comply with the NSPS, the above figures do not include any estimate of the number of replacement devices or the emissions reductions that will occur as a result of their compliance with the NSPS.

3. Critiques

EPA's proposal must be improved by limiting an exemption for high-bleed devices, by extending the instances in which no-bleed devices are used, by defining "low-bleed" consistently with modern industrial practice, and by extending the standards to all pneumatic devices, including pneumatic pumps.

a. Limit The "High-Bleed" Exemption

EPA suggests that "[t]here may be situations where high-bleed controllers . . . are necessary due to functional requirements, such as positive actuation or rapid actuation."[214] It thus proposes to allow operators to "demonstrate, to the Administrator's satisfaction, that the use of a high-bleed device is predicated."[215] This demonstration "may include, but is not limited to, response time, safety and actuation."[216] This exemption is vague, will allow for excessive emissions, and is not properly enforceable.

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[212] TSD at 5-1.
[213] *See* TSD, Table 5-4 at 5-10.
[214] 76 Fed. Reg. at 52,761.
[215] 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390(a)),
[216] *Id.*

Initially, if EPA retains such an exemption at all, it must define the precise terms under which it can be granted. If there are particular circumstances where a particular high-bleed rate is *necessary* – not "predicated," which is an impermissibly unclear term – EPA must set out those circumstances in regulatory text, rather than providing a vague, non-exclusive list of qualities, like "safety," that any operator may cite in an attempt to avoid the standard. Instead, EPA must define particular requirements that only high-bleed controllers can meet, and require operators to prove that such circumstances are present before an exemption is granted. Unless EPA specifically defines the narrow circumstances in which it will consider allowing for excessive emissions, the exemption has the potential to overwhelm the rule.

Further, EPA must limit the upper bound of the exemption. As drafted, it allows operators to avoid *any* restrictions on the bleed rates of their high-bleed pneumatic controllers. But even the limited class of necessary high-bleed controllers must not be allowed to emit without limit. EPA must therefore draw a hard line for emissions rate above which no exemption will be granted.

EPA must also define the process by which such an exemption would be granted. It needs to specify when an operator must apply for an exemption, how it shall apply – by letter to the Administrator, for instance – how EPA will consider such requests, and how the public may be involved. The public, in particular, has a vital interest in such exemptions: Pneumatic controllers are a major source of harmful VOCs, and so directly implicate public health. Members of the public must be able to comment upon, and challenge, EPA's exemption decisions before the Environmental Appeals Board or a similar body. EPA has provided for such appeal rights in other air quality rulemakings, including in rulemakings focused solely on emissions *monitoring*.[217] Surely, such an appeal right is all the more important in rules focused upon emissions *control*.

b. Extend the Use of No-Bleed Controllers

EPA proposes to base its standard on the use of no-bleed instrument air systems only in natural gas processing plants because it believes that the electricity needed to power these systems will not be available in other settings.[218] This assumption is not supported by data in the record.

Natural gas is now produced in many developed areas, such as in Fort Worth, Texas, where significant production exists within the city borders, and southwestern Pennsylvania, in the vicinity of Pittsburgh. As a result, many pneumatic devices currently installed where electricity is readily available, and emissions of natural gas

[217] *See, e.g.*, 75 Fed. Reg. 76,060, 75,067 (Dec. 1, 2010) (revising EPA appeal provisions to allow members of the public to challenge EPA's approvals of certain greenhouse gas monitoring provisions before the Environmental Appeals Board), attached hereto as Exhibit 85

[218] 76 Fed. Reg. at 52,760.

from bleed devices, snap-acting pneumatics, and other pneumatic equipment (chemical injection pumps, etc.) are released in proximity to local populations.

EPA must set a zero-emissions standard based upon no-bleed pneumatic controllers when electricity is available within a reasonable distance, particularly when multiple devices are clustered within a single area.

For remote locations, as the Copeland and Williams report demonstrates, based upon EPA's own data, no-bleed systems are regularly being used in some instances where grid electricity is not available. Solar-powered controllers, fuel-cell powered controllers, and mechanically-controlled devices are all being used in the field. Most notably, BP reported using solar power panels to replace gas-powered devices, with a payback period of just four years.[219] Copeland and Williams also demonstrate that Colorado and Wyoming require production sector no-bleed systems, where feasible. These technologies may well constitute BSER for a broad class of production systems.

EPA must find as much and set a zero emissions standards based upon no-bleed devices wherever electricity, either from the grid or from field power sources, is available within a reasonable distance from the facility. To do so, it could structure the rule in ways parallel to its "high-bleed" exemption by establishing a rebuttable presumption that no-bleed devices must be used, except where low-bleed devices are necessary because no-bleed devices cannot feasibly be installed.

c. Properly Define "Low-Bleed"

EPA uses a 6 scf per hour bleed rate to define "low-bleed" controllers.[220] But, as the Sahu report discusses, this bleed rate, drawn from twenty-year old documents, is far higher than what modern technology can achieve in many circumstances.[221]

EPA itself states that "low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh."[222] Put differently, EPA apparently acknowledges that the *least* effective low-bleed device "on the market today" has an emission rate that is 1 scfh *lower* than the 6 scfh standard it proposes to set.

A 6 scfh standard therefore cannot constitute BSER for this facility type. We remind EPA that BSER is to be set based upon "what may be fairly projected for the regulated future, rather that the state of the art at present."[223] EPA has not even adopted a standard based upon "the state of the art at present," much less what the regulated future may hold.

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[219] *See* Copeland and Williams Report at 34-36.
[220] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390(c))
[221] Sahu Report at 15-16.
[222] TSD at 5-3.
[223] *Lignite Energy Council v. U.S. EPA*, 198 F.3d at 934.

Instead, a more carefully-drawn standard is warranted. Different bleed rates among pneumatic devices correspond to different functions for those devices. As EPA recognizes, higher bleed rates may be associated with devices with shorter response times, for instance.[224] This means that controllers in some situations may be able to achieve the minimum bleed rate identified in EPA's TSD of 0.2 scfh, while some other classes of controllers may hover closer to the 5 scfh upper limit. Although *no* "low-bleed devices on the market today" has emissions of 6 scfh, according to EPA's analysis, this functional variation means that EPA must set standards by class of control device.

EPA must therefore define a maximum bleed rate for each functional class of pneumatic controller, setting each bleed rate to force technological improvements, consistent with the goals of the NSPS program. This range of allowable bleed rates must, of course, extend no higher than 5 scfh, the highest bleed rate supported in the record. For each class of controller, EPA must fully justify that its standard is no higher than the lowest emission rates that each class of controller can achieve.

Finally, we understand that some purported low-bleed pneumatics may not perform as advertised under all circumstances, or if poorly maintained. This heightens the importance of including rigorous leak detection and monitoring standards in the final rule in order to ensure that EPA captures the full benefits of its proposal.

d. Extend Control Standards to All Pneumatic Devices

EPA uses both the terms pneumatic "device" and pneumatic "controller" in the preamble, but the control standards apply only to pneumatic controllers.[225] This is a serious oversight, which EPA must correct, because the category of well-field pneumatics devices is broader than "controllers," and includes snap-acting devices, chemical injection pumps, and other devices.

In particular, pneumatic *pumps* are a significant emissions source, and those emissions can be controlled. Wyoming, for instance, requires that such pumps achieve a 98% control efficiency, or route all their emissions into closed loop systems.[226] Thus, controls which can achieve this level of reduction are not only available, but are actually in use. EPA must require them here.

In fact, EPA appears to have considered doing so, as a definition of "pneumatic pump" remains in Proposed 40 C.F.R. § 60.5430. EPA must now follow through and control this

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[224] 76 Fed. Reg. at 52,761.
[225] *See* Copeland & Williams Report at 37-38.
[226] *See id.* at 37 n. 141 (citing See Wyoming Department of Environmental Quality, Air Quality Division, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010 ("Wy. Guidance") at 9, 19.

emissions source or, at a minimum, provide a legally sufficient rationale as to why it will not do so.

Above we assert that EPA must base the standard on "zero-bleed" pneumatic *controllers* unless operators demonstrate that electricity is not feasibly available on site. In general EPA's standards should require that these other pneumatic *devices* be converted to "zero-bleed" (instrument air, electrical actuation, mechanical actuation, etc.) in conjunction with requirements for zero-bleed pneumatic controllers.

C. Compressors

1. EPA's Proposal

EPA proposes to treat each centrifugal or reciprocating compressor located between the wellhead and the city gate, except those located at the well site, as an affected facility.[227] EPA determined, for both reciprocating and centrifugal compressors, that fugitive emissions from these sources cannot be reliably measured or controlled. It therefore set a design and work practice standard under section 111(h) for these sources (and hence is bound by that section's BTSER standard, as we discuss above).[228]

EPA estimates that new centrifugal compressors at processing and transmission and storage sites, if uncontrolled, will annually emit 5,408 tons of methane, 377.9 tons of VOCs, and 13.25 tons of HAPs; non-wellhead reciprocating compressors will annually emit 8,100 tons of methane, 2,090.73 tons of VOCs, and 78.63 tons of HAPs.[229] Clearly, these emissions are significant.

Under the proposed NSPS, all new or modified centrifugal compressors must use a dry seal system upon initial startup.[230] New or modified reciprocating compressors must replace rod packing before the unit reaches 26,000 hours of operation, and units must continuously monitor hours of operation to ensure compliance with this standard.[231]

2. BTSER Determination

We generally agree that among centrifugal compressors, use of dry seals as opposed to wet seals is BTSER. Dry seals are a better option than the option to use "wet seals combined with routing of emissions from the seal liquid through a closed vent system to a control device" because of the adverse collateral impacts of flares.[232] We further

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[227] 76 Fed. Reg. at 52,799. (Proposed 40 C.F.R. § 60.5365(b)-(c)).
[228] *See* 76 Fed. Reg. at 52,762-63 (explaining these determinations); 42 U.S.C. § 111(h) (providing for such standards).
[229] TSD at 6-10.
[230] 76 Fed. Reg. at 52,800. (Proposed 40 C.F.R. § 60.5380(a)).
[231] *Id.*. at 52,800. (Proposed 40 C.F.R. § 60.5385(a)).
[232] *Id.* at 52,746.

agree that among reciprocating compressors, frequent rod packing replacement is BTSER.

We also agree that each compressor is properly considered an affected "facility," subject to EPA's proposed standards. As we explained above, each compressor is plainly an "apparatus" properly regulated under section 111, and installation of a new replacement compressor is construction subject to the NSPS because the regulations define "construction" as "fabrication, erection or installation of an affected facility."[233]

As we explain below, however, we disagree with EPA's treatment of the two compressor technologies as inherently distinct. EPA must investigate whether dry seal centrifugal compressors represent BTSER for compressors generally. If dry seal centrifugal compressors are determined to have the lowest emissions, then EPA must use that emission rate as its "achievable" emission limitation standard. Indeed, because EPA is setting "design, equipment, work practice, or operational standards,"[234] it should be able simply to require centrifugal compressors as a design standard for new installations, such that new installations of reciprocating compressors would be prohibited by the NSPS. In this event, EPA must nonetheless also promulgate a rod-packing standard, which must apply to existing reciprocating compressors that are "modified" under CAA § 111(a).

We also disagree, in several regards, with how EPA has proposed to implement its requirements. As occurs throughout the proposal, EPA has allowed for improperly broad exemptions, and impermissibly high emissions rates. It must correct these errors in order to promulgate legal final standards.

3. Critiques

a. Centrifugal Compressors

Although we support the use of dry seals as BSER, EPA must specifically require the use of "tandem" or double dry seal systems.[235]

As EPA has explained, wet seals may leak between 40-200 scf per minute (scfm), while dry seals can reduce emissions to 6 scfm or below (some EPA estimates put such leaks at just 0.5-3 scfm).[236] These replacements can pay for themselves in as little as 11 months,

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[233] 40 C.F.R. § 60.2 (2010).
[234] 42 U.S.C. § 7411(h)(1).
[235] Copeland and Williams 30-32.
[236] EPA Natural Gas STAR, *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors,* attached hereto as Exhibit 86; *see also* EPA, *Methane Savings from Compressors and VRUs* (July 27, 2006) at 12 (showing low emissions from dry seals and concluding that such seals "often used in tandem" are profitable to install in many circumstances), attached hereto as Exhibit 87.

according to EPA, and can then generate hundreds of thousands of dollars in savings annually.[237] Dry seals are readily available, and are used throughout the industry.[238]

All dry seals are not equivalent, however. Tandem seals substantially improve emissions control. According to EPA, such seals are "very effective in reducing gas leakage," as "[t]his type of seal has less than one percent of the leakage of a wet seal system vented in to the atmosphere and costs considerably less to operate."[239] Indeed, according to one prominent vendor, tandem dry seals are now "[t]he most popular configuration used in the industry."[240]

Nonetheless, EPA's proposal does not specify the use of tandem dry seals, or, indeed, even provide a definition of the "dry seal system" that EPA requires.[241] EPA must correct this error. EPA needs to require all centrifugal compressor sources to use *tandem* dry seals, and to clearly define "dry seal system" accordingly.

b. Reciprocating Compressors

For new facilities, EPA must investigate whether the NSPS should require the use of centrifugal compressors instead of reciprocating compressors as BTSER.

As a threshold issue, EPA must more thoroughly examine reciprocating compressor emissions. The data EPA has provided, however, permits the following extrapolation. EPA's posits that the average reciprocal compressor with newly installed but worn-in rod packing will leak 11.5 scfh per cylinder.[242] Other sources have indicated that reciprocating compressors with newly installed rod packing can leak as much as 60 scfh, apparently from a single cylinder.[243] EPA has also stated that a compressor with worn rod packing may leak 900 scfh from a single cylinder.[244] Although EPA did not specifically explain how much use led to this level of wear, EPA has also stated that "conventional bronze-metallic packing rings wear out and need to be replaced every 3

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[237] *See id.* at 1.
[238] *See, e.g.*, Dresser-Rand, *Dry Gas Seals* (vendor offering seals and noting that "[b]ecause of their advantages, dry gas seals are now installed on 95% of new compressors for varied service throughout the world"), attached hereto as Exhibit 88; Trem Engineering, *Mechanical Seals and Dry Gas Seals for Oil and Gas* (2010) (vendor offering dry seals and tandem dry seals), attached hereto as Exhibit 89; Globalspec, *Dry Gas Seal Configuration* (explaining how "state-of-the-art tandem gas seal designs" have become popular), attached hereto as Exhibit 90; Rolls-Royce, *Centrifugal Compressors* (describing availability of tandem dry seals in Rolls Royce designs), attached hereto as Exhibit 91.
[239] *Id.* at 4.
[240] Kaydon Ring & Seal Inc., *Dry Gas Seals* at 2. attached hereto as Exhibit 92.
[241] *See* 76 Fed. Reg. at 52,800. Proposed 40 C.F.R. § 60.5380.
[242] Copeland and Williams at 24 n.96 (citing TSD 6-12 to 6-14).
[243] Sahu Report at 20 n.80 (citing Reducing Emissions from Compressor Seals, Lessons Learned from Natural Gas Star, September 22, 2004. Available at www.epa.gov/gasstar).
[244] Natural Gas Star (2006), "Reducing Methane Emissions from Compressor Rod Packing Systems" Available at http://www.epa.gov/gasstar/tools/recommended.html, attached hereto as Exhibit 93.

to 5 years, depending on the compressor's rate of usage."[245] Absent further detail, we assume that 900 scfh represents the leak rate of a reciprocating compressor cylinder at the end of this 3 to 5 year lifecycle.[246] We further assume, for purposes of this comment, that rod packing emissions increase linearly across their lifespan, absent specific information about the trajectory of emissions. Based on these figures and assumptions, we estimate that a reciprocating compressor cylinder emits an average of 456 scfh across its lifespan when rod packing is replaced after three years of operating time.[247] Each compressor has an average of 2.5 – 4.5 cylinders,[248] so a conservative estimate is that an average compressor emits about 1,500 scfh.

This estimate suggests that centrifugal compressors equipped with dry seals (even a single dry seal) have fewer emissions than even well maintained reciprocating compressors.[249] As explained in Dr. Sahu's report, dry seal centrifugal compressors are observed to emit the equivalent of 30 to 180 scfh, while reciprocating compressors, again, may be emitting 1,500 scfh or more. *Id.* Furthermore, data from the US Greenhouse Inventory shows that the average centrifugal compressor is many times larger (higher horsepower) than the average reciprocal compressor.[250] As a result the comparison above underestimates the lower emissions of centrifugal compressors. Accordingly, BTSER-level emissions are set by the centrifugal compressors. Therefore, as EPA sets equipment standards for this industry, it must require the use of centrifugal compressors instead of reciprocating compressors wherever such use will not impose unbearable costs on industry.[251]

If EPA does not take this course, it must strengthen the rod packing standard for reciprocating compressors. As noted, wear and tear on rod packing assemblages can increase emissions from 12 scfh to 900 scfh. EPA proposes to require replacement before 26,000 hours of use, the equivalent of three years of continuous usage. EPA should have evaluated a more aggressive rod packing replacement schedule. A more aggressive schedule might result in further cost *savings* to operators by avoiding methane losses. For example a "120 scfh leak reduction rate would require roughly 2 years payback assuming a gas cost of $7/Mcf, a 10% interest rate and 8,000 hours of operation."[252] Of course, the BTSER standard must go beyond only requiring those emission reductions that are actually profitable to the operator. The above merely

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[245] 76 Fed. Reg. at 52,762.
[246] Sahu Report at 26.
[247] *Id.*
[248] TSD at table 6-2, page 6-4.
[249] Sahu Report at 20.
[250] Comparison based on emissions factors and activity data in tables A-121 and A-122, pp. A-153 – A-154, *US Greenhouse Gas Inventory*.
[251] As we later discuss, a rod-repacking standard should, however, be retained for existing reciprocating compressors if and when EPA regulates those facilities.
[252] Copeland and Williams Report at 30 n.125, *see also* Lessons Learned, Natural Gas STAR Partners, "Reducing Methane Emissions from Compressor Rod Packing Systems", p. 8 (October 2006) http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

demonstrates that EPA must investigate whether to shorten the 26,000-hour replacement schedule.

We also ask that EPA consider whether a leak-detection based emissions regime, requiring replacement when emissions cross a certain threshold, constitutes BSER. Because rod packing replacement quickly pays for itself in many scenarios, such a threshold could be low. Some compressors may begin to leak significantly long before the 26,000 hour operation time, but EPA's time-based replacement standard will not address these leaks. If such early failures are at all common, EPA's proposal will unnecessarily allow excess emissions, and so will not constitute BSER. EPA must evaluate this possibility, and, if it declines to adopt a leak-based threshold, must explain why it does not do so.

Beyond rod packing replacement, EPA must evaluate requiring installation of advanced rod packing materials.[253,254]

c. Scope of the Standard

EPA must revisit its decision to exclude wellhead compressors from the NSPS. Wellhead compressors represent a significant fraction of the number of compressors; for example, EPA's figures indicate that 13% of all emissions from new reciprocating compressors are predicted to come from reciprocating compressors at wellheads.[255] With the rapid growth in gas production in recent years, this fraction will grow.

EPA excluded reciprocating wellhead compressors from the standard on the basis of the low VOC emissions from these compressors.[256] EPA has not explained how it determined the level of these emissions. It must do so. EPA appears to have relied, in part, on the conclusion that wellhead compressors are typically "small."[257] A compressor engine survey conducted in Texas states the following: "Some of the findings of this . . . study include: 1. Generally, less than 1% of the well-head engine capacity is comprised by engines smaller that 50 hp; and 2. Generally, 50 to 73% of the well-head engine capacity is comprised by engines greater than 500 hp, depending on

[253] Copeland and Williams, 30.
[254] Rod repacking materials are readily available. *See, e.g.*, EPA, *Methane Savings from Compressors and VRUs* (July 27, 2006) at 5-6 (quantifying emissions reductions and cost savings from rod repacking); EPA, *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems* at 3 (concluding that "[m]onitoring and replacing compressor rod packing systems on a regular basis can greatly reduce methane emissions to the atmosphere and save money"); CECO, *Reduce Gas Emissions: Install CECO Low Emission Packing* (vendor offering rod repacking); CECO, *Low Emission Packing* (2010) (same), attached hereto as Exhibit 94.
[255] Copeland and Williams at 26-39.
[256] 76 Fed. Reg. at 52,762.
[257] *Id.*

the region."[258] We do not consider engines greater than 500 hp as "small." Thus, EPA's assertion regarding the size of the typical wellhead compressor appears unwarranted. We are similarly unable to verify EPA's calculations of the emission rate for wellhead reciprocating compressors (estimated by EPA as 0.044 tpy VOC) or the cost per ton of reducing these emissions (estimated at $84,000).[259] Thus, although EPA purports to distinguish wellhead reciprocating compressors from other reciprocating compressors, this distinction is unsupported, and unreasonable. If EPA wishes to retain the exemption, it must justify it on the record.

EPA has provided no explanation whatsoever regarding its decision to exclude wellhead *centrifugal* compressors from the standard.[260] It must do so. In the absence of a compelling rationale to the contrary, wellhead compressors (of both varieties) must be subject to the same standards as other compressors in the production sector. While EPA does not report methane emissions from wellhead centrifugal compressors in its Greenhouse Gas inventories, implying that there were few or zero centrifugal compressors at wellheads when the basic research behind the inventory was carried out some time ago, this may no longer be true. In any case centrifugal compressors may be installed at wellheads in the future.

d. Compressor Exhaust

EPA has also failed to set a standard for emissions from compressor exhaust. Exhaust from reciprocating internal combustion engines (RICE) and turbines which drive natural gas compressors is a very significant source of methane emissions. In 2009, compressor exhaust accounted for 552,000 metric tons of methane emissions, or 4.6% of the total methane emissions from the oil and gas sector.[261]

While exhaust from some new compressor engines and turbines is addressed under existing standards such as 40 CFR Part 60 Subparts JJJJ and KKKK, according to EPA, these standards do not address methane. EPA offered no evidence that the emissions controls that those standards do require effectively reduce methane. Methane is less reactive than many hydrocarbons[262] and may escape destruction via catalytic oxidation, demonstrating that these other existing standards may be inadequate. Below, we discuss, at length, EPA's obligation to control methane as a pollutant from this sector.

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[258] Houston Advanced Research Center, *Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities, H68 Final Report* (October 2006) pp. 3, attached hereto as Exhibit 95.
[259] 76 Fed. Reg. at 52,762, Sahu at 20-24.
[260] *See* 76 Fed. Reg. at 52,761.
[261] US EPA (2011), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, tables A-120 – A-123 (pp. A-149 – A-155). Figures include scaling for emissions reductions reported to Natural Gas STAR.
[262] Sander, S. P., J. Abbatt, J. R. Barker, J. B. Burkholder, R. R. Friedl, D. M. Golden, R. E. Huie, C. E. Kolb, M. J. Kurylo, G. K. Moortgat, V. L. Orkin and P. H. Wine (2011), "Chemical Kinetics and Photochemical Data for Use in Atmospheric Studies, Evaluation No. 17," JPL Publication 10-6, Jet Propulsion Laboratory, Pasadena. http://jpldataeval.jpl.nasa.gov, attached hereto as Exhibit 96.

Compressor exhaust provides a clear instance where such controls are necessary, and EPA must, therefore, regulate methane from compressor exhaust.

According to emissions factors in the US Greenhouse Gas Inventory, turbines produce less methane (per horsepower-hour) than RICE engines by about a factor of 25.[263] Above, we demonstrate that because centrifugal compressors leak less than reciprocating compressors, centrifugal compressors are the BTSER for VOC emissions from certain compressors. Centrifugal compressors are powered by turbines, unlike reciprocating compressors that are driven by RICE (either can alternatively be powered by electric motors, with zero emissions). Therefore, requiring centrifugal compressors as BTSER will have a substantial co-benefit for methane reductions in the engine/turbine exhaust. A requirement for compressors to be driven by turbines (or electric motors where electricity is available) would therefore be a logical compliment to the centrifugal compressor requirement.

EPA has previously recognized that this is a cost-effective methane abatement option.[264] It must impose standards to control compressor exhaust here.

D. Storage Vessels

1. EPA's Proposal

Because EPA has also proposed (substantively identical) storage vessel standards for new and existing vessels under its proposed NESHAP, the proposed NSPS covers only new and modified vessels not addressed by the NESHAP.[265]

The NSPS standard applies to storage vessels, defined as:

> a stationary vessel or series of stationary vessels that are either manifolded together or are located at a single well site and that have potential for VOC emissions equal to or greater than 10 [tons per year].[266]

Under that standard, storage vessels would essentially have to comply with the NESHAP standard (which is incorporated into the NSPS). That standard requires vessels to be equipped with a cover and closed-vent system, or control device, that channels all

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[263] See emissions factors list in US EPA (2011), Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, tables A-120 – A-122 (pp. A-149 – A-154).

[264] US EPA (2003), *International Analysis of Methane and Nitrous Oxide Abatement Opportunities: Report to Energy Modeling Forum, Working Group 21*, Appendix B, available at http://www.epa.gov/methane/appendices.html, attached hereto as Exhibit 97.

[265] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5395(b)). *See also id.* at 52,769 (proposing to expand the existing NESHAP to cover all storage vessels, not just those with the potential for flash emissions).

[266] *Id.* at 52,810 (Proposed 40 C.F.R. § 60.5430).

emissions to either a combustion device (or flare) or vapor recovery unit ("VRU") with at least 95% control efficiency by weight.[267]

2. BSER Determination

EPA estimates that uncontrolled VOC emissions from storage vessels, in the absence of the NSPS, would be 21,373 tons per year for condensate storage and 23,421 tons per year for crude oil storage.[268] Vapor recovery units, or combustion devices with 95% control efficiency, can reduce VOC emissions by 29,654 tons per year (in 2015).[269]

Assuming, as EPA does, that half of facilities use combustion devices and half use VRUs, EPA's proposed rule would achieve significant VOC reductions at just $143/ton (accounting for additional revenues from recovered condensate).[270]

This is an eminently reasonable control cost, and is reflected in the wide use of vessel emissions control measures throughout the industry. As the Copeland and Williams Report discusses, similar (and more rigorous) control technologies are already in wide use, including in Wyoming, where a 98% control efficiency is required.[271]

EPA Natural Gas STAR documents also support these emissions controls. EPA partners report significant emissions reductions and financial gains. Chevron USA Production Company, for instance, installed VRUs on eight crude oil storage tanks and recovered over $1.2 million in savings, while reducing methane emissions by 21,900 Mcf per year from each unit. The project paid for itself in three months.[272]

We therefore agree with EPA that some combination of combustion devices and VRU on storage tanks, at am minimum, constitutes BSER for this class of facilities. As we discuss below, however, the statute requires EPA to look further, toward emerging control options and improperly excluded sources, in order to set legal emissions standards for this part of the industry..

3. Critiques

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[267] *Id.* at 52,815-16 (Proposed 40 C.F.R. §§ 63.766, 63.771).
[268] TSD at 7-12.
[269] RIA at 3-17.
[270] As we discuss below, it seems likely that combustion devices will be used more frequently than VRUs. This will somewhat raise control costs (though they will remain eminently reasonable). Below, we urge EPA to work to reduce the use of flares, as they produce additional air pollution, while VRUs do not.
[271] Copeland and Williams Report at 54. *See also* Wy. Guidance at 5, 11, 18 (requiring such controls).
[272] EPA Natural Gas STAR, *Lessons Learned from Natural Gas STAR Partners: Installing Vapor Recovery Units on Crude Oil Storage Tanks* (2006) at 10, available at: http://www.epa.gov/gasstar/documents/ll_final_vap.pdf, attached hereto as Exhibit 98.

Field data and state regulations demonstrate that EPA must raise control efficiency requirements, and minimize flaring, in order to ensure that the proposed standards reflect BSER. In addition, EPA must limit exemptions to these standards and cover all storage vessels and similar impoundments, pits, sumps, and well cellars, including those that contain produced water. EPA must also revise the regulatory text to eliminate confusing cross references which may impede compliance and enforcement efforts.

a. Tighten Emission Control Requirements

EPA must raise its control efficiency requirements and limit, or eliminate, the use of combustion devices.

Initially, EPA provides only limited support for the proposition that a 95% control efficiency constitutes what may be "fairly projected for the regulated future."[273] On the contrary, EPA's own Natural Gas STAR documents report that VRUs can "recover *over* 95 percent of the hydrocarbon emissions that accumulate in storage tanks."[274] A 98% control efficiency is, again, achievable, and is required in Wyoming.[275] Because these controls are widely-used, their level of control is plainly "[a]n achievable standard."[276] EPA's proposal thus falls below BSER, and must be strengthened.[277]

We are also unpersuaded that EPA has achieved the right balance between VRUs and flares, in light of the serious adverse environmental impacts of flaring. As EPA explains:

> A VRU has a potential advantage over flaring, in that it recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold, as well . . . . A VRU also does not have secondary air impacts that flaring does . . . .[278]

These flaring impacts include NO_x, SO_2, and PM emissions, as well as emissions of other pollutants.[279] EPA must avoid these impacts wherever feasible.

We recognize that EPA determined it could not simply select VRUs as reflecting BSER for storage vessels because "a VRU cannot be used in all instances."[280] But that is not the statutory standard for new source emissions under 111(b). EPA must ensure that VRU-

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[273] *Lignite Energy Council*, 198 F.3d at 934.
[274] EPA Natural Gas STAR, *Lessons Learned from Natural Gas STAR Partners: Installing Vapor Recovery Units on Crude Oil Storage Tanks* (2006) at 1.
[275] *See* Wy Guidance at 5, 11, 18 (requiring such controls).
[276] *See Essex Chem. Corp.*, 486 F.2d at 433.
[277] *See also* Copeland and Williams Report at 50 (describing these higher control efficiencies).
[278] 76 Fed. Reg. at 52,763.
[279] *See id.*; *see also* TSD at 7-17 (listing flaring emissions, including THC, CO, CO_2, NOx, SO_2, and PM).
[280] 76 Fed. Reg. at 52,763.

level control efficiencies are achieved in all applications so long as that does not impose exorbitant costs on industry (EPA now predicts that only 50% of new sources will use VRUs, while the remainder will flare.)[281] It must do so by requiring all affected sources to achieve control efficiencies of 98%, with no secondary emissions of NO_x, except where the operator can demonstrate to EPA that it cannot install a VRU. In that case (and only that case) EPA could allow a 95% control efficiency (which can be met either by VRU or flare), with that exemption subject to review or challenge. Such an approach is structurally similar to EPA's efforts to construct an exemption from its "low-bleed" standard for controllers,[282] and would similarly hold operators to a higher standard, with limited exemptions. EPA must adopt it.

b. Limit Exemptions

EPA proposes to exempt "small throughput" storage vessels – that is, vessels with either an average condensate throughput of less than 1 barrel per day per vessel or average oil throughput of less than 20 barrels per day per vessel.[283] These throughput rates translate into a 6.1 ton per year per tank VOC emission rate for condensate tanks and a 5.8 ton per year per tank VOC emission rate for crude oil tanks.[284] This exemption is not lawful.

Initially, EPA's own calculations show that the annualized cost of installing a VRU is $18,983 and $8,909 for a flare – translating into control efficiencies of about $3,000 per ton of VOC emissions reduced for a VRU (depending on the tonnage of emissions captured).[285] These are not exorbitant costs – certainly far less than the greatest that "the industry could bear and survive."[286] In exchange for these costs, EPA would significantly reduce VOCs at these facilities – by 5.77 tons per year per tank for condensate tanks and 1.4 tons per year per tank for crude oil tanks.[287] These are substantial emissions reductions at fairly low costs. EPA must, therefore, either abandon or strictly limit the exemption.

If the exemption is limited, however, rather than abandoned, it must be revised in several respects:

First, in order to avoid exempting substantial cumulative emissions from tank farms that contain numerous tanks which may fall below EPA's applicability threshold, EPA must structure its exemption (whatever the thresholds) to apply to tank batteries, rather than

[281] TSD at 7-24
[282] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390(a))
[283] *Id.* at 52,800 (Proposed 40 C.F.R. § 60.5395(a)(1)-(2)).
[284] TSD at 7-19, 7-21.
[285] These projected costs are likely too high. *See infra* Section VII(B)(2)(f).
[286] *See Portland Cement II*, 513 F.2d at 508.
[287] *See* TSD at 7-19, 7-21.

to individual tanks.[288] This may be what EPA intended the current proposal to accomplish, because its proposed storage vessel definition includes a "series of stationary vessels that are either manifolded together or are located at a single well site."[289] This intent is not clear from the preamble, however. EPA must therefore either confirm that its standards (and exemptions) are intended to apply to vessels both individually and cumulatively, or must revise them accordingly.

Second, EPA must, at a minimum, limit the exemption to truly small tanks with truly small emissions. Because the public experiences adverse impacts from *emissions*, rather than throughput, EPA must base its exemption on emissions thresholds. These thresholds must be set at the lowest reasonable point, which is below the current thresholds.

Specifically, for condensate storage vessels, a 3 ton/year emissions rate would reach 1,782 tanks, reducing each tank's emissions by 95%, at a cost of only $6,576 per ton of VOC. For crude oil tanks, a 1.5 ton/year emissions cut-off would trigger 95% emissions reductions at 825 tanks for $13,686/ton. These costs are clearly reasonable, and will produce substantially greater benefits than those flowing from the thresholds that EPA proposes to use. We therefore assert that EPA must limit its exemption to tanks with these lower emissions rates.

We further note in this regard that EPA's cut-off in proposed 40 C.F.R. § 60.5395 appears to be in tension with its underlying storage vessel definition. That definition defines storage vessels as including only those tanks that "have potential for VOC emissions equal to or greater than 10 tpy."[290] But even using EPA's proposed thresholds, the smallest emissions rate tanks covered by the standards would have emissions of 6.1 tons per year (condensate) and 5.8 tons per year (crude oil).[291] EPA presumably does not intend to exempt tanks with these emissions from all control just because their emissions are below 10 tons per year of VOC. EPA must therefore delete the "10 tpy" language from its definition section, as it conflicts with the lower emissions threshold it sets in the substantive storage vessel standard itself.

Third, EPA should further condition its exemption by limiting it to only small throughput tanks with low vapor pressure. Such an exemption would ensure that only tanks which do not contain significantly volatile substances are exempt.

Such vapor pressure limitations are used in certain California air quality districts. The Santa Barbara County Air Pollution Control District, for instance, exempts tanks whose vapor pressure is below 0.5 lb/sq. in,[292] and the Ventura County Air Pollution Control

[288] *See* Sahu Report at 24-25.
[289] 76 Fed. Reg. at 52,810 (Proposed 40 C.F.R. § 60.5430).
[290] 76 Fed. Reg. at 52,810 (Proposed 40 C.F.R. § 60.5430).
[291] TSD at 7-19, 7-21.
[292] SBAPCD Rule 325(B)(1)(a), attached hereto as Exhibit 99.

District takes a similar approach (using VOC content rather than vapor pressure), and exempts tanks with a VOC concentration of 5 mg/L of water or below.[293] EPA must follow suit and condition its exemption similarly.

c. Address Additional VOC Sources Arising from Liquid Storage

Storage vessels are not the only liquid storage systems that emit VOCs. Well cellars, sumps, and even pools of oil can and do emit substantial VOCs, which are controlled by several different state regulators. EPA must include standards for such sources based upon these available controls.

Examples of such controls are plentiful, especially among the California air districts. In particular:

- The South Coast Air Quality Management District prohibits well cellars with a total organic compound concentration of greater than 500 ppm,[294] bars organic liquid storage in well cellars, and requires regular monitoring,[295] Since 2006, no well cellar may vent any natural gas to the atmosphere.[296]

- The Santa Barbara County Air Pollution Control District requires regular pumping of well cellars.[297] It also bars all "primary sumps" – that is, any sump that receives oil and produced water directly from field gathering or production systems – and requires that all pits and post-primary sumps (which receive their liquids after separation processes) be replaced with tanks or covered, with a vapor recovery unit.[298]

- The Ventura County Air Pollution Control District likewise bars "first stage production sumps" and requires all other sumps, pits, and pounds to be covered.[299]

- The San Joaquin Valley Air Pollution Control District requires all sumps to be covered with a material impervious to VOCs.[300]

- The Bay Area Air Quality Management District bars all "open liquid pools of crude oil or condensate" and all uncovered vessels larger than 250 ml; it also requires that all well cellars be covered.[301]

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[293] VCAPCD Rule 71.4(C)(1)(c), attached hereto as Exhibit 100.
[294] SCAMD Rule 1148.1(d)(1), attached hereto as Exhibit 112
[295] Rule 1148.1(d)(2)-(3).
[296] Rule 1148.1(d)(6).
[297] SBCAPCD Rule 344(D)(3), attached hereto as Exhibit 113
[298] Rule 344(D)(1)-(2).
[299] VCAPCD Rule 71.4(B)
[300] SJVAPCD Rule 4402(5), attached hereto as Exhibit 114

EPA neither discusses these precedents, nor acknowledges the existence of VOCs from sumps, pools, and well cellars. As a result, it has unreasonably left these sources unregulated.

In the final rule, EPA must include standards for each liquid storage source, including, but not limited to, sumps, pools, pits, pounds, and well cellars, or provide a legally-supportable rationale as to why it will not follow the (decades-old) control precedent set by the California air quality control districts.

d. Address Produced Water

Produced water storage (including ponds and tanks) constitutes an important subset of the liquid storage systems we discuss above. Produced water is a significant VOC source, and EPA must control it properly.

First, at an absolute minimum, EPA must make clear that its proposed standards apply to produced water tanks. Wyoming already requires new produced water *tanks* to achieve the same 98% emissions control that it requires of crude oil and condensate tanks.[302] The Santa Barbara County Air Pollution Control District likewise requires produced water tanks to be controlled to a 90% efficiency.[303] These examples demonstrate that controls are plainly available and effective, but EPA has not included produced water tanks in its storage vessel definition. It must do so.

Second, EPA needs to develop controls for produced water ponds and sumps, holding these sources to a similarly rigorous control efficiency standard.

EPA "believes that produced water ponds are . . . a potentially significant source of emissions," and is seeking comment on control options for these ponds.[304] We agree that produced water can produce significant VOC emissions. Some reports do establish that these ponds emit harmful pollution. EPA research has shown that produced water ponds used by the oil and gas industries can emit VOCs including the hazardous pollutants benzene, toluene, xylenes, and methanol.[305] New York State has also gathered data on emissions from impoundments, and concluded that these impoundments could be significant sources of the hazardous air pollutant methanol:

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[301] BAAQMD Rules 8-37-302 & 8-37-303, attached hereto as Exhibit 115
[302] Wy Guidance at 16, 20.
[303] *See* SBCAPCD Rules 344(D)(2)(a); 325(D).
[304] 76 Fed. Reg. at 52,756.
[305] Thoma, E. (2009) *Measurement of Emissions from Produced Water Ponds: Upstream Oil and Gas Study #1. Final Report.* EPA Report EPA/600/R-09/132. Available at http://www.epa.gov/nrmrl/pubs/600r09132/600r09132.pdf, attached hereto as Exhibit 101.

> Analysis of air emission rates of some of the compounds used in the fracturing fluids in the Marcellus Shale reveals potential for emissions of hazardous air pollutants (HAPs), in particular methanol, from the recovered (flowback) water stored in central impoundments. This methanol is present as a major component of the surfactants, cross-linker solutions, scale inhibitors and iron control solutions used as additives in the frac water. Current field experience indicates that an approximately 25% recovery of fracturing water from Marcellus shale wells may be expected. Thus, using a 25% recovery factor of a nominal 5,000,000 gallons of frac water used for each well, an estimated 6,500 pounds (3.25 tons) of methanol will be contained in the flow- back water. Since methanol has a relatively high vapor pressure, its release to the atmosphere could possibly occur within only about two days after the recovered water is transferred to the impoundment. Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission of 32.5 tons (i.e., "major" quantity of HAP) is theoretically possible at a central impoundment.[306]

Because VOCs and hazardous air pollutants are likely co-emitted from these sources, they appear to be potentially significant emissions sources, warranting coverage by these standards.

Pit emissions can be estimated using EPA's own test methods. The Ventura County Air Pollution Control District uses EPA Method 8015, which requires sampling of only a small portion of the pit surface.[307]

As we discuss above, California air districts in areas with oil and gas production have long controlled emissions from produced water ponds, by, for instance, requiring such ponds to be covered, or that their emissions be captured or flared, or simply by requiring ponds to be replaced by tanks.[308] These standards are described in the section above, on liquid storage.

The Santa Barbara County Air Pollution Control District, the Ventura County Air Pollution Control District, and the Bay Area Air Quality Management District, in particular, have all banned at least certain forms of open liquid storage (such as "primary sumps"), ordering that they be replaced with well-controlled tanks (equipped with appropriate

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[306] *Draft New York Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Program* (Sept. 30, 2009) at section 6.5.1.8, attached hereto as Exhibit 102. New York's recent revised impact statement (Sept. 2011) does not contain this statement, but only because "[t]he Department was informed in September 2010 that operators would not routinely propose to store flowback water either in reserve pits on the wellpad or in centralized impoundments" and therefore did not address "these practices" in the revised document. *See* Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program (September 2011) at section 1.1.1.1, attached hereto as Exhibit 103.
[307] VCAPCD Rule 71.4(F).
[308] See VCAPCD Rule 71.4 & SBCAPCD Rule 325.

flares or VRUs). Tanks are inherently more readily managed then pits, so the lowest-possible emissions rate from a tank constitutes BSER.

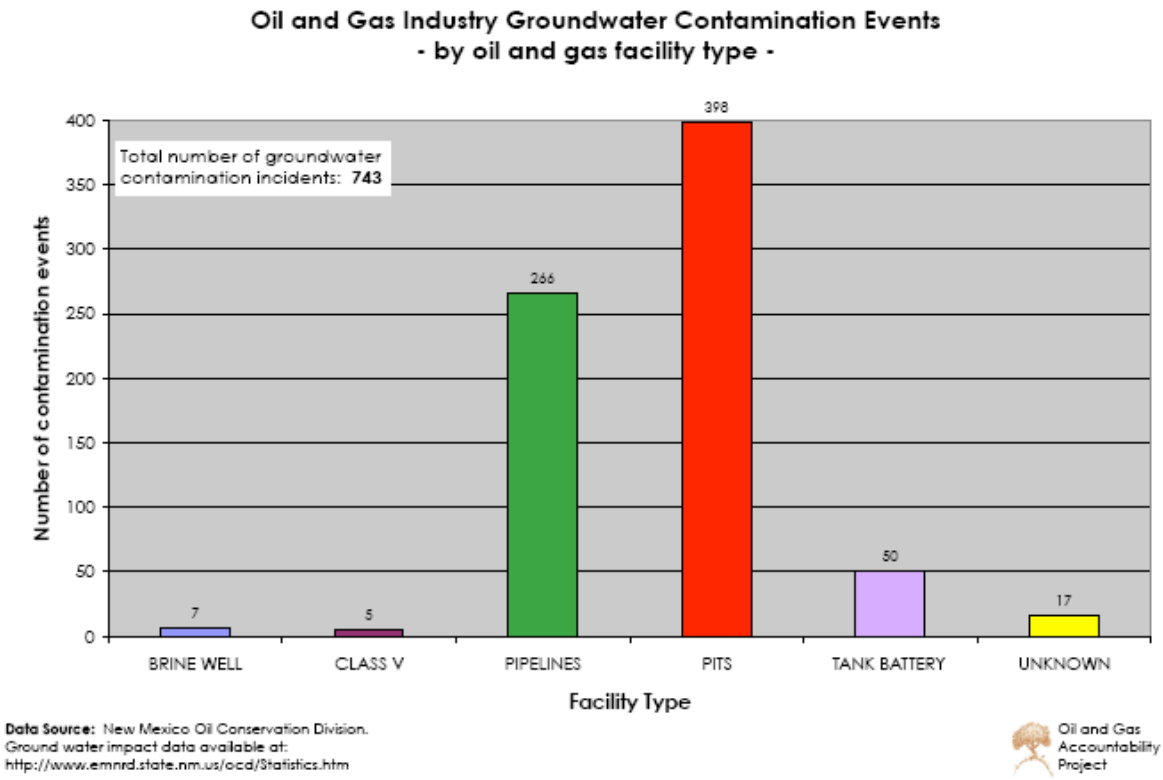
Because this technology is available, and in use, it plainly constitutes BSER for liquids storage. EPA must therefore set emissions standards for produced water based upon the emissions rate from well-controlled tanks. (And, to the extent it determines that some classes of produced water storage cannot be managed in tanks, EPA must continue to follow the path blazed by the California air districts, and set BSER standards based, at a minimum, upon *covered* and well-controlled impoundments).

Such a standard also would produce significant "non-air quality health and environmental" benefits, especially to the extent that operators opted to avoid using pits, in lieu of tanks, and because covers help prevent spills and falls into pits. Surface spills and leaks from waste pits pollute water across the country, so eliminating these pits would greatly reduce water pollution issues associated with oil and gas extraction. The open pits and ponds also pose a significant risk to livestock and to wildlife, such as birds that alight on them and small animals that use them for drinking water.

For instance, New Mexico data, summarized by the Oil and Gas Accountability Project, show 743 instances of ground water contamination, almost all of it occurring over the last three decades. 398 of those incidents – over half – are linked to faulty pits.[309]

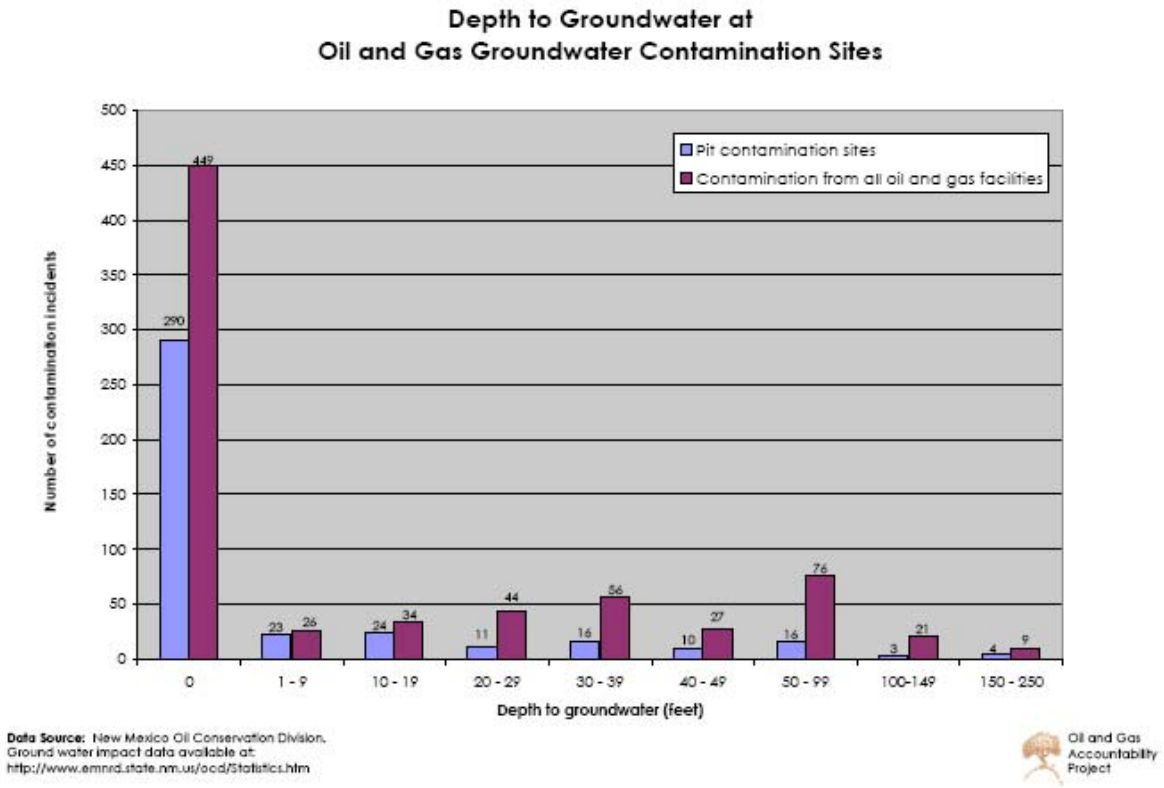
Figure 3

[309] OGAP Analysis of data provided in New Mexico Energy, Minerals and Natural Resources Dep't, Oil and Conservation Div., *Cases Where Pit Substances Contaminated New Mexico's Ground Water* (2008). OGAP Analysis and raw data available at http://www.earthworksaction.org/NM_GW_Contamination.cfm, attached hereto as Exhibit 104.



The bulk of pit contamination is associated with shallow groundwater, of the sort which can readily flow into drinking water wells, as the New Mexico data demonstrate:

Figure 4



Similar incidents are occurring across the country. [310] In Pennsylvania, for instance, state authorities were forced to quarantine cattle after a pit leaked into their field, collecting in a smelly pool that killed the grass.[311] In Colorado, leaky pits with torn liners spilled more than 6,000 barrels of waste,[312] and one leaking pit contaminated drinking water with benzene. In state after state, poorly-regulated and inspected pits are imperiling the public.

Thus, EPA rules requiring produced water to be sequestered in tanks, or, at a minimum, discouraging the use of uncovered pits by setting rigorous emission control standards, would not only control VOCs, but also make important progress on controlling water pollution from these sources.

To the extent that EPA needs additional data to support such a requirement, e.g., data on emissions from pits, available controls for achieving substantial emission control

[310] *See generally*, Natural Resources Defense Council, Petition for Rulemaking to Regulate Oil and Gas Waste (Sept. 8, 2010) (collecting these incidents), attached hereto as Exhibit 105.

[311] Pro Publica, Nicolas Kusnetz, *A Fracking First in Pennsylvania: Cattle Quarantine* (July 2, 2010), available at http://www.propublica.org/article/a-fracking-first-in-pennsylvania-cattle-quarantine, attached hereto as Exhibit 106.

[312] *See* Colorado Oil and Gas Conservation Commission, Inspection/Incident Inquiry, Spill Reports Doc. Nos. 1630424, 1630436, 1630427, 1630428, 1630429, 1630430, all attached hereto as Exhibit 107.

from pits, and/or costs of converting from pits to tanks, it must specifically request such information from companies under section 114.

e. Textual Issues

Finally, EPA must revise the rule text to avoid cross-references to its NESHAP standard. At present, the proposed rule simply cites to the NESHAP for its emission standards,[313] but this cross-citation is confusing, as the cited sections – and the sections that they, in turn, cite – are rooted in section 112 concepts, and include references to hazardous air pollutant control requirements. EPA must, therefore, place its NSPS emission control standards directly in the text of the NSPS rule.

E. Leak Detection

1. EPA's Proposal

In proposing the revised NSPS, EPA evaluated potential leak detection and repair ("LDAR") requirements for all facilities in the oil and gas production sector. EPA considered four potential LDAR programs: (1) monthly monitoring in accordance with 40 C.F.R. subpart VVa; (2) annual monitoring to the standard imposed by subpart VVa plus monthly optical monitoring; (3) monthly optical monitoring alone; and (4) annual optical monitoring alone.[314] Based on this evaluation, EPA proposes to adopt subpart VVa for processing plants but not to adopt any LDAR requirement for other oil and gas production facilities.

Specifically, under the existing regulation, 40 C.F.R. subpart KKK, § 60.632(a), onshore natural gas processing facilities must comply with subpart VV, but EPA proposes to update the standard to require compliance with subpart VVa.[315] All other facilities are currently unregulated, and EPA concluded that no LDAR program was "cost effective" for these facilities, accordingly declining to adopt a standard.[316]

2. Critique

We agree that subpart VV no longer reflects BSER for onshore natural gas processing plants, and that subpart VVa presents a feasible and cost-effective improvement. Nonetheless, EPA must go further before it is compliant with the statute. It must consider various combinations of subpart VVa and optical monitoring. State programs and consent decrees EPA has entered both demonstrate the efficacy and feasibility of stricter programs with fewer exemptions, and EPA must adopt a stronger standard here.

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[313] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5395(a))
[314] 76 Fed. Reg. at 52,754-55 (discussing processing plants), 52,764-66 (discussing other facilities).
[315] 76 Fed. Reg. at 52,800, (Proposed 40 C.F.R. § 60.5400). Both VV and VVa were developed for the Synthetic Organic Chemicals Manufacturing Industry.
[316] 76 Fed. Reg. at 52,766.

As to other facilities, although EPA determined that an overall LDAR program was unwarranted, EPA must have examined whether LDAR was warranted for particular device types.

a. Processing Plants

The existing VOC regulations for natural gas processing facilities, 40 C.F.R. subpart KKK, incorporate the LDAR provisions of 40 C.F.R. subpart VV. The subpart VV standards were developed in 1981, and subpart KKK was adopted in 1985.[317] Since that time, much has been learned about what it takes to have an effective leak detection program. Notably, investigations by EPA Regional and National Enforcement Investigations Center personnel detected massive fraud in the conduct of LDAR inspections and in the reporting of results.[318] Enforcement action induced negotiations with operators of most of the nation's refineries led to consent decrees that substantially improved the real-world effectiveness of those programs and the development of Best Practice Guidelines.[319] Similarly, various states and regional entities have adopted LDAR programs.[320,] Many of these consent decrees and state regulations are more stringent than the subpart VVa regulation EPA proposes to adopt for processing plants. Yet EPA's BSER review did not examine these activities and practices. EPA must either adopt elements of these more stringent programs as BSER or explain why these elements are infeasible.

The most basic elements of an LDAR program are the definition of a leak (expressed as parts per million of the leaked substance), the frequency of monitoring, and the timeline in which leaks are repaired once discovered. Subpart VVa improves upon subpart VV by reducing the leak detection threshold: for pumps in light liquid service, the leak threshold is lowered from 10,000 ppm to 2,000 ppm, and for valves in gas/vapor and

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[317] 50 Fed. Reg. 26122 (June 14, 1985) (Exhibit 1); *see also* 50 Fed. Reg. 40158 (Oct. 1, 1985) (Exhibit 2).

[318] In the late 1990's EPA discovered flagrant, industry-wide violations of several CAA requirements at the nation's refineries. Among the most significant violations were LDAR rules violations where refiners, and independent contractors hired by refiners, routinely underreported by up to a factor of 10 the number of leaking valves, leading to significant excess emissions. The ensuing enforcement actions led to 29 settlements with operators over 90 percent of the refining capacity in the country. These settlements required improved LDAR practices, $82 million in fines and $75 million in Supplemental Environmental Projects. This experience demonstrates a need for detailed independent oversight of LDAR activities, as does the recent Pelican refinery criminal prosecution. In the absence of a sustained Federal focus on this issue and recognizing the likely lack of state resources in the near future, it would seem that MACT should include some form of independent auditing of LDAR programs. EPA could require an independent audit of sources with large number of components, perhaps once every five years.

[319] See, e.g., Leak Detection and Repair, A Best Practices Guide, p. 22-23, http://www.epa.gov/compliance/resources/publications/assistance/ldarguide.pdf (discussing these consent decrees), attached hereto as Exhibit 108

[320] *See, e.g.*, Bay Area Air Quality Management District regulation 8-18 (adopted Sept. 15, 2004), attached hereto as Exhibit 109

light liquid service, where the leak threshold is lowered from 10,000 ppm to 500 ppm.[321] EPA does not propose to strengthen the monitoring frequency and repair times. The Bay Area Air Quality Management District ("BAAQMD") has demonstrated that stricter regulation is feasible. The BAAQMD supervises LDAR programs at 5 refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under Regulation 8, Rule 18 (Reg 8-18). This regulation, first adopted in 1998, sets lower leak limits, more frequent inspections, and shorter repair schedules than the proposed rule, as summarized in Table 1, below.

Table 1

	Current Rule	Proposed Rule	BAAQMD Rule 8-18
Leak definition – valves in gas/vapor/light liquid services	10,000 ppm	500 ppm	100 ppm
Leak definition – pumps in light liquid service	10,000 ppm	2,000 ppm	500 ppm
Inspection frequency	Monthly/quarterly[322]	Monthly/quarterly	Quarterly/annual[323]
Repair schedule	15 days[324]	15 days	7 days[325]

In addition to having a lower leak threshold, the BAAQMD rule is stricter than the VV and VVa rules because it requires monitoring for methane leaks. Subparts VV and VVa (with incorporation of EPA Method 21) do not specifically require the use of leak detection equipment which is sensitive to methane. Since methane is the main component of natural gas, this oversight can potentially significantly diminish the effectiveness of leak detection at a specified threshold. EPA should therefore either specify that leak-detection equipment be sensitive to methane and adopt BAAQMD's lower threshold or explain why these steps are infeasible for natural gas processing plants.[326]

[321] It should be noted that the 10,000 ppm limit is an absolute limit; while the limit of 500 ppm is "500 ppm above background." Reportedly, background concentrations can be expected to be approximately 100 ppm.

[322] If a component is not found to be leaking in two consecutive months; the inspection frequency is reduced to once per quarter. Thus, the majority of components are inspected quarterly

[323] Pumps are subject to daily visual inspection. If a valve has not been found to be leaking during five quarterly inspections, the inspection frequency is reduced to once per year.

[324] An initial attempt to repair must be made within 5 days.

[325] If the leak is detected by BAAQMD personnel during an inspection it must be repaired within 24 hours. The BAAQMD rules also require that leaks detected by the source be minimized within 24 hours.

[326] As noted, BAAQMD has applied these rules to refineries, chemical plants, and terminals. Although BAAQMD does not appear to regulate any natural gas processing plants, EPA has historically subjected natural gas processing plants to the same regulations as these other facility types.

Another key aspect of an LDAR program is the scope of any exemptions recognized by the program. Subpart VV exempts devices from monitoring if it is "unsafe" or "difficult" to monitor them.[327] Subpart VV further allows operators to delay repair of leaking devices: an operator may delay repair of devices where repair would require a shutdown of the process, and an operator may forgo repairs of 2% of the total number of devices provided the operator conducts weekly rather than monthly monitoring.[328] These exemptions were carried over into Subpart VVa.[329] EPA must review these exemptions in light of the experience in California and elsewhere and determine whether exemptions at these levels continue to be consistent with the notion of "best system of emission reductions." For example, BAAQMD does not recognize an exemption for devices that are unsafe to monitor. Similarly, whereas the proposal would allow 2% of devices to be designated as nonrepairable, BAAQMD limits the number of nonrepairable devices to 0.025% to 1%, depending on the device category.[330]

A particularly troubling exemption in EPA's proposed standard is that EPA proposes to waive LDAR requirements where the gas stream is less than 10% VOC by weight. Proposed subsection 60.5400(f) states that:

> [e]ach piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process.

EPA's preamble provides no discussion of this exemption, and we are aware of no basis for it. This LDAR exemption will likely apply to many, if not all, compressors, valves, pressure relief devices and connectors downstream of processing unit dehydrators; indeed, EPA reports that processed gas is only 2.8% VOC by weight.[331] Although devices used with low-VOC gas streams will by definition have lower VOC emissions, VOC leaks from these devices may still be significant. Addressing these leaks will certainly have important methane benefits. Accordingly, EPA must either remove the exemption or provide a justification for continuing to provide it.

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[327] 40 C.F.R. §§ 60.486(f), 60.482-2(g), 60.482-7(g)-(h), 60.482-10(j)-(k).
[328] 40 C.F.R. §§ 60.483-1, 60.482-7(a)(2)(ii).
[329] 40 C.F.R. §§ 60.486a(f), 60.482-2a(g), 60.482-7a(a)(2)(ii), (g), (h), 60.482-10a(j)-(k), 60.482-11a(e), 60.483-1a, 60.483-2a(b).
[330] The BAAQMD limit on the number of non-repairable components it 0.3 percent for valves, 0.025 percent for valves with major leaks (leaks greater than 10,000 ppm, including methane) and 1.0 percent for pumps and compressors. It also requires mass emission testing for non-repairable components with high leak rates and places an emission limit of 15 pounds per day on non-repairable components. The SCAQMD limit is 0.5 percent for valves and 1.0 percent for pumps.
[331] *See* TSD at 6-2.

The LDAR program furthermore must incorporate elements beyond thresholds and schedules. The alternate compliance option and allowable level of designated "difficult to monitor" valves must be reviewed in light of the performance of best performing LDAR programs. For example, EPA must limit the exemptions for devices that are difficult or unsafe to monitor or repair by providing that when such devices are replaced, they must be replaced with hermetically sealed (leakless) designs. Use of advanced "leakless" components in these locations should be cost-effective since (1) the cost of monitoring, repairing and re-monitoring devices that are difficult to monitor is substantially higher than components in more convenient locations; (2) the conversion to leakless technology would only occur when a new valve is being installed; and (3) the potential emissions from leaking "inaccessible" components is greater since a leak is less likely to be observed visually or by sense of smell and instrumented monitoring only occurs annually. Since the NSPS only applies to newly installed components, advanced technology components must be required at the time of initial installation for those components that, if they leaked, would require a plant shutdown to repair. EPA must also explore whether optical scanning provides a way to monitor devices that would be difficult or unsafe to monitor using traditional monitoring techniques.

Another approach EPA must use is to require "repeat offenders" to be replaced. The South Coast Air Quality Management District and the Ventura County Air Pollution Control District each have rules under which components that have been subject to repair more than, *e.g.*, 5 times within a year be replaced with BACT/BARCT or be vented to an approved air pollution control device.[332]

Finally, EPA must ensure the integrity of the LDAR program. As EPA's history of enforcement actions demonstrates, this integrity cannot be taken for granted.[333] EPA has, as we note above, encountered significant fraud in previous leak detection efforts. To avoid this, it must include safeguards in its rules, including requiring a professional engineer to sign off on all LDAR reports. EPA must also explore requiring periodic independent audits of LDAR programs, at least for larger processing plants.

Optical Scanning

In three of its four options, EPA considered the use of optical scanning devices as a means of reducing LDAR inspection frequencies, and EPA specifically requested comment on the role of optical scanning. Current and even advanced LDAR programs

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[332] See, SCAQMD Rule 1173(g)(3), attached hereto as Exhibit 110 and Ventura County APCD Rule 74.7, attached hereto as Exhibit 111. Under the Ventura County rule, for example, if a valve is found to have suffered 5 major leaks in a year is shall be replaced by a valve with a bellows seal, or with graphite, PTE or PTFE stack chevron seal rings, or with BACT technology level components.

[333] For a more recent example, see EPA's recent refinery settlements. See, e.g. http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html, attached hereto as Exhibit 116.

have been shown to be cost-effective BSER. EPA is correct that optical scanning devices have not been shown to be as effective as LDAR programs, and, as pointed out, cannot quantify emissions. Optical scanning programs can, however, be a part of an overall improved LDAR program. Use of optical cameras involves some modest level of investment; however, once purchased, these devices can provide an extremely low cost means of filling the gaps in the LDAR program. Daily or weekly scans can identify plant areas containing gross emitters (including "unsafe to monitor" or "difficult to monitor" components) for targeted LDAR inspections. Such inspections could replace scheduled inspections and save operators money by detecting leaks early, while improving the environmental performance of the facility. Use of optical scanning devices, pressure relief valves, monitoring devices and other technical advances can complement existing programs. However, the suite of existing options have not demonstrated the ability to provide the level of emission reductions as can be obtained from well-designed and implemented LDAR programs. For this reasons these options must be considered in addition to and not *in lieu of* existing programs.

Defining affected facilities

The Clean Air Act provides that NSPS apply to "stationary source[s]," which include individual "facilit[ies]." CAA §§ 111(a)(3), (b)(1). Each individual NSPS defines the "affected facilities" it regulates. *Star Enter. v. EPA*, 235 F.3d 139, 142 (3d Cir. 2000), *Sierra Pac. Power Co. v. EPA*, 647 F.2d 60, 66 (9th Cir. 1981).

The proposed regulation, as it applies to onshore natural gas processing plants, defines "affected facility" to include two things: an individual "compressor in VOC service or wet gas service," or "[t]he group of all equipment, except compressors, within a process unit." Proposed 40 C.F.R. § 60.5365(f)(1)-(2). "Process unit" is defined as "components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products." § 60.6430.

Operators and enforcement staff are likely to disagree over what constitutes a "process unit." The definition must be expanded to include all common gas processing processes, as follows:

> Gas processing plant process unit means equipment assembled for dehydration of natural gas, the sweetening of gas, the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

b. Non-Processing-Plant facilities

EPA does not propose any form of LDAR for non-processing-plant facilities, including the wellheads, compressors, pneumatics, and storage facilities otherwise regulated by the proposal.[334] EPA concluded that the two options involving subpart VVa-type monitoring were not "cost effective." [335] For the two options involving solely optical monitoring, EPA was "unable to estimate their cost effectiveness" because EPA could not estimate the amount of VOC reductions these programs would achieve.[336]

At a minimum, EPA must evaluate whether monitoring is BSER for specific components, and justify its decision not to apply it. For example, EPA concluded that Subpart VVa had a cost of control of $6,079 per ton of VOC as applied specifically to valves at gathering lines and boosting stations, and that modified subpart VVa as applied to these same valves had a cost effectiveness of $5,221 per ton.[337] Although EPA has not articulated a cutoff for reasonable control costs, these numbers resemble other figures that EPA has concluded are cost effective. For example, in discussing LDAR for processing plants, EPA concluded that switching from subpart VV to subpart VVa would have a cost-effectiveness of $3,352 per ton of VOC, including $4,360 for connectors, and that this was cost-effective.

Furthermore, it appears that EPA's cost estimates are unduly conservative, in that two prior studies found LDAR programs to be more cost-effective than does the current proposal. EPA's own 2009 Methane to Markets presentation identified drastically lower LDAR costs per device monitored.. A separate Canadian study determined that, *inter alia*, 75 to 85 percent of leaks are economic to repair. Thus, EPA may be overstating the cost of LDAR programs for non-processing-plant facilities, and EPA must at least reconcile its current cost estimates with those in EPA's 2009 Methane to Markets report.

F. SO_2 Emissions from Gas Processing Plants

1. EPA's Proposal

Gas processing plants are significant SO_2 sources because the removal of H_2S from "sour" gas results in SO_2 emissions.[338] EPA's Subpart LLL control standards, which are calibrated by the sulfur feed rate at a given facility, set a maximum required control efficiency of 99.8% for facilities with sulfur feed rates greater than 5.0 long tons/day

[334] 76 Fed. Reg. at 52,766.
[335] *Id.*
[336] *Id.* at 52,765-66.
[337] 76 Fed. Reg. at 52,765.
[338] *See* 49 Fed. Reg. 2,656, 2,658 (Jan. 20, 1984) (describing these emissions), attached hereto as Exhibit 117.

(LT/D) and a gas stream with greater than 50% H_2S content.[339] These standards were set in 1984, and EPA now proposes to update them. A database search shows two facilities which meet EPA's feed rate and H_2S content standards which can achieve a 99.*9*% control efficiency.[340] EPA therefore proposes to raise its maximum control efficiency to 99.9%, consistent with these achieved emissions reductions.

2. BSER Determination

We agree with EPA that, as facilities with high sulfur feed rates can achieve a 99.9% control efficiency, the existing 99.8% feed rate no longer reflects BSER/BDT. We therefore support EPA's decision to raise the maximum required control efficiency consistent with control rates achieved by the sources in EPA's database.

G. Conclusion

In sum, EPA's proposal is a substantial improvement over the status quo, but must be improved to be fully compliant with section 111's forward-looking technology forcing requirements as we describe above.

III. EPA MUST ADD SEVERAL MISSING SOURCE TYPES TO THE NSPS

Throughout these comments, we have noted opportunities for EPA to control certain source categories which the rules do not now appear to cover, including conventional well liquids unloading and produced water ponds and tanks. Three other omitted source types are also important here, and must be included in the standards because section 111, as we discuss above, requires EPA to comprehensively regulate each listed source category (or justify its failure to do so) upon each eight year review and revision. These source categories are: (a) offshore sources, (b) heater-treaters; and (c) oil and gas field engines, including rig engines.

A. Offshore Sources

EPA has the authority, and the obligation to regulate the emissions of portions of the offshore oil and gas production sector. The Outer Continental Shelf Lands Act ("OCSLA") explicitly *extended* the "laws and civil and political jurisdiction of the United States" to the Outer Continental Shelf, cementing the relevance of domestic environmental law to that region.[341] In doing so, Congress recognized that the shelf is "a vital national resource reserve held by the Federal Government for the public," and which is "subject to environmental safeguards."[342] In fact, Congress even ordered the Secretary of the

[339] *See* 40 C.F.R. § 60.642.
[340] 76 Fed. Reg. at 52,755-56.
[341] *See* 43 U.S.C. § 1333(a)(1).
[342] *See* 43 U.S.C. § 1332(3).

Interior, who oversees leasing programs in the region, to "cooperate with the relevant departments and agencies of the Federal Government" to enforce "environmental laws."[343]

The Clean Air Act provides, in turn, that following the passage of the 1990 Amendments, EPA:

> [s]hall establish requirements to control air pollution from Outer Continental Shelf sources located offshore of the States along the Pacific, Arctic, and Atlantic Coasts, and along the United States Gulf Coast off the State of Florida eastward of longitude 87 degrees and 30 minutes ("OCS sources") to attain and maintain Federal and State ambient air quality standards *and* to comply with the provisions of [the Prevention of Significant Deterioration Program].[344]

Section 111 standards are, of course, designed to "supplement" ambient air quality standards by ensuring that new and modified sources of air pollution in all areas comply with rigorous emissions controls.[345] As such, EPA must extend these regulations to "attain and maintain" air quality to OCS sources.

The Act goes on to specify that, for OCS sources "located within 25 miles of the seaward boundary of such states":

> such requirements shall be the same as would be applicable if the source were located in the corresponding onshore area, and shall include, but not be limited to, State and local requirements for emission controls, emissions limitations, offsets, permitting, monitoring, testing, and reporting.[346]

The NSPS clearly fit within this inclusive collection of requirements, even though they are federal requirements, as they are, again, regulations designed that support attainment and maintenance of air quality standards. And the use of "shall" in the directive from Congress to establish regulations aimed at attaining and maintaining the NAAQS and comply with the PSD program indicates that EPA must extend the NSPS in over Outer Continental Shelf sources.

Significantly, Congress declared that EPA "shall update such requirements as necessary to maintain consistency with onshore regulations."[347] Because EPA is updating the NSPS for onshore sources, it must therefore update and extend the NSPS to corresponding offshore sources within the 25 mile boundary.

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[343] *See* 43 U.S.C. § 1334(a).
[344] 42 U.S.C. § 7627(a)(1).
[345] *See*, *e.g.*, *NRDC v. Train*, 545 F.2d 320 (2nd Cir. 1976), attached hereto as Exhibit 118.
[346] 42 U.S.C. § 7627(a)(1).
[347] *Id.*

It is particularly important that EPA do so because emissions from offshore sources are significant. Indeed, according to EPA's most recent greenhouse gas inventory, in petroleum systems:

> The most dominant sources of emissions, in order of magnitude, are *shallow water offshore oil platform*s, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, *deep water offshore platforms*, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas.[348]

Because VOCs are generally co-emitted with methane, especially in the production segment, offshore sources also will be significant VOC sources.

Yet, EPA neither proposes standards for offshore oil and gas production, nor justifies its failure to do so. The Clean Air Act requires EPA propose and finalize such standards.

B. Heater-Treaters

Heater-treaters, which are small boilers used to separate oil and gas emulsions, are common in both oil and gas fields, but EPA has not proposed standards for them. It must do so.

Although individual heater-treaters are relatively small sources of NO_x and CO, thousands of them are used in the production process. As the Colorado Department of Public Health and Environment explained in its recent regional haze state implementation plan, although individual heater-treaters "often fall below regulatory thresholds," there are huge numbers of such sources in use and projected for the future – 26,000 are projected by 2018 in Colorado alone.[349] As a result, heater-treaters will be the largest single area source NO_x emitters in Colorado by that year, emitting 22,901 tons per year of NOx, plus 4,809 tons per year of CO.[350]

To address these emissions, EPA has recommended voluntary use of operational standards, and numerous California air districts have set emissions standards. To wit:

- EPA recommends that operators reduce heater-treater temperatures to the minimum effective temperature. EPA notes that these combustion savings will

[348] EPA, *Inventory of U.S. Emissions and Sinks 1990-2009* (2011) at 3-49.
[349] Colorado Department of Public Health and Environment, *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*, Appendix D at 1 (2011)
[350] *Id.*

reduce methane emissions by 142 Mcf per year per heater-treater, paying for themselves in fuel savings.[351]

- The San Diego County Air Pollution Control District sets emissions standards for small boilers and process heaters (with heat inputs between 600,000 BTU to 2 million BTU/hr) of 30 ppm NOx (for gaseous fuels), 40 ppm NO_x (for liquid fuel), and 400 ppm CO. .[352]

- The South Coast Air Quality Management District sets emissions standards for NOx from boilers, steam generators, and process heaters with heat inputs between 2 million and 5 million BTU. By 2008, operators were required to cut their emissions to 30 ppm NO_x (or 0.037 lb NO_x /mmBTU for gas-fired units). By 2015, emissions must fall further, to 12 ppm for atmospheric units, and 9 ppm for natural-gas fired units. CO emissions are limited to 400 ppm.[353]

- The San Joaquin Valley Air Pollution Control District sets emissions standards for small boilers, steam generators, and process heaters with heat inputs between 75,000 BTU and 2 million BTU/hr. As of January 2011, units below 400,000 BTU were limited to 0.024 lb NO_x /hr (for gas-fired units) and 0.093 lb NOx/hr (for non-gas units); larger gas units must meet the same standard, while larger non-gas units must meet a 0.036 lb NO_x /hr standard. All units are limited to a 400 ppm CO standard.[354]

- The Ventura County Air Pollution Control District's small boiler, steam generator, and process heater rules apply to units with heat inputs between 1 million and 5 million BTU/hr. Such heaters are limited to a 30 ppm NO_x standard and a 400 ppm CO standard.[355]

- The Santa Barbara County Air Pollution Control District small boilers, steam generators, and process heaters rules covers units with heat inputs between 2 million and 5 million BTU/hr. It, too, imposes a 30 ppm NO_x and 400 ppm CO standard.[356]

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[351] EPA Natural Gas STAR, *Lower Heater-Treater Temperature, PRO Fact Sheet No. 906*, attached hereto as Exhibit 119.
[352] SDCAPCD Rule 69.2.1, attached hereto as Exhibit 120
[353] SCAQMD Rule 1146.1, attached hereto as Exhibit 121.
[354] SJVAPCD Rule 4308, attached hereto as Exhibit 122.
[355] VCAPCD Rule 74.15.1. attached hereto as Exhibit 123.
[356] SBCAPCD Rule 361, attached hereto as Exhibit 124.

Controls can be imposed in various ways, running from simply lowering heater-treater temperatures and insulating units to tuning heater-treaters regularly to increase combustion efficiency, as many of the California air districts require.[357]

In short, heater-treaters are extremely numerous NO_x and CO emissions sources found throughout oil and gas fields. These emissions are readily subject to control and have been controlled, for years, by California regulators. But because each individual heater-treater's emissions will be relatively minor, heater-treaters are unlikely to be directly regulated in many states, or under federal major source permitting programs. Section 111 regulation is necessary, as a practical matter, to ensure that this cumulatively major emissions source is properly controlled.

Yet EPA fails even to recognize this facility type, much less set standards. EPA must set standards no less stringent than those employed in the California air districts (that is, at least no less stringent than the common 30 ppm NO_x and 400 ppm CO standard).

C. Field Engines and Turbines, Including Drilling Rig Engines

EPA acknowledges that "[s]ignificant emissions of [NO_x] . . . occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors through the system, and from combustion of natural gas in heaters and boilers."[358] But EPA declines to control these emissions because it asserts that these sources, though "co-located" on production sites, are "not in the Oil and Natural Gas source category" and instead are addressed by the subpart JJJJ and KKKK performance standards. EPA also, without discussion, excludes drilling rig engines from its standards. EPA does not support its decision to exclude these sources from its proposal, nor show that other standards are sufficient to control their emissions.

Emissions from this equipment have been implicated in significant air quality problems in several areas. For example, in the Pinedale Anticline supplemental environmental impact statement in Wyoming, NO_x emissions from drill rigs were estimated at 2,590 tons per year (tpy) in 2005 and 3,232 tpy in 2009 under the proposed action.[359] This represents more than six times the NO_x emissions from compression activities and 5.8 to 6.1 times the fugitive NO_x emission rates from pad construction, traffic, and completions.

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[357] *See, e.g.*, VCAPCD Rule 74.15.1 Att. 1 (describing tuning procedure); SCAQMD Rule 1146.1 Att. 1 (same).
[358] 76 Fed. Reg. at 52,756.
[359] *Air Quality Impact Analysis Technical Support Document for the Revised Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Proje*ct at 11 (Table 2.1), "Pinedale SEIS TSD," attached hereto as Exhibit 125.

NO_x emissions are a significant precursor of very harmful ozone events and of visibility impairment in nearby Class I areas. Ozone levels have exploded in the Pinedale, Wyoming area, reaching 8-hour averages of 122 parts per billion in February, 2008.[360] Emissions from natural gas production, particularly NO_x, have been implicated in these highly unusual winter-time ozone extremes.[361] Visibility impairment due to direct project source emissions has reached 45 days per year with over 1 dv of visibility impairment—6.1 dv maximum visibility impact—in 2005 in the Bridger Wilderness Area.[362]

Thus, EPA must address NO_x emissions (and emissions of other pollutants) from these sources, or demonstrate that they are sufficiently addressed by other Clean Air Act standards. It must take further action to do so, in several regards:

First, EPA must close relevant gaps in coverage of the performance standards for engines and turbines used in the oil and gas sector, such as NSPS Subparts IIII, JJJJ, and KKKK, and the non-road mobile source engine rules. One clear gap is the current exemption for turbines with heat inputs below 10 million BTU per hour.[363] These sources are plainly part of the oil and gas source category, and EPA must include them in its standards, yet it has not.

Second, as we discuss above, subparts IIII, JJJJ, and KKKK do not address all pollutants from engines and turbines used on production sites. Most notably, compressor exhaust contains significant amounts of methane,[364] which is not controlled by the subpart JJJJ and KKKK standards. These emissions will go uncontrolled unless EPA issues revised standards, perhaps in a supplemental proposal.

Third, because EPA is obligated to ensure that its review and revision of its standards for the oil and gas sector is complete, it must demonstrate on the record that all significant pollution sources from the sector have been addressed. As such, EPA must provide a clear analysis of emissions from drill rigs and other oil and gas field engines, showing (1) the types and numbers of engines that are not regulated under other provisions; (2) the emissions resulting from any gap in regulatory coverage, and (3) a description of how EPA plans to address these emissions, if it declines to promulgate standards in this

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[360] Wyoming Dept. of Enviro. Quality, (2008) "Air Pollution Advisory: Ozone For Upper Green River Basin/Sublette County," 27 February 2008. http://www.pinedaleonline.com/news/2008/02/AirPollutionAdvisory.htm, attached hereto as Exhibit 126.

[361] Schnell, R.C, et al. (2009), "Rapid photochemical production of ozone at high concentrations in a rural site during winter," *Nature Geosci.* 2 (120 – 122). DOI: 10.1038/NGEO415.

[362] Final Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project, Vol. 2, at 16-9 (Table 16.9) and 18-13 (Table 18.16). attached hereto as Exhibit 127.

[363] 40 CFR § 60.4305.

[364] *See supra* Section X.

rulemaking. In other words, EPA may not simply assert that these emissions are controlled elsewhere; it must demonstrate that that is the case.

IV. EPA MUST ADD STANDARDS FOR SEVERAL MISSING POLLUTANTS TO THE NSPS

EPA must regulate each dangerous pollutant emitted by sources in the oil and gas source category in more than *de minimis* quantities,[365] for which controls are available. It has failed to do so. This failure is serious: It leaves dangerous pollutants unregulated. In particular, EPA must regulate methane, particulate matter, hydrogen sulfide, and nitrogen oxides from oil and gas operations. EPA's explanation of why it declined to regulate certain pollutants does not even discuss particulate matter or hydrogen sulfide, or address the most important sources of nitrogen oxides, and does not offer a legal justification for its failure to regulate methane.

EPA's duties to regulate these pollutants arise directly from the statutory text, and from decades of agency practice.

Congress clearly intended Section 111 to address the full scope of air pollution emitted by a source category. The plain language of section 111 requires no less, repeatedly referring to the regulation of "any" air pollutant emitted by sources subject to regulation under this section. For example, Congress defined stationary sources to which NSPS apply as including facilities that emit or may emit "any air pollutant."[366] Likewise, Congress defined "modification" of existing sources – which in turn become subject to the NSPS – as "any physical change in, or change in method of operation of, a stationary source which increases the amount of *any* air pollutant emitted . . . or which results in the emission of *any* air pollutant not previously emitted."[367] That Section 111 applies to sources of "any" air pollutant is strong evidence that the Section is designed not only to *apply* to those sources but to *control* pollution resulting from "any" pollutant.[368]

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[365] Any such de minimis exemption would have to be thoroughly justified on the record; such exemptions are not routinely available.

[366] 42 U.S.C. § 7411(a)(3).

[367] *Id*. § 7411(a)(4) (emphases added).

[368] The Act provides additional evidence of Congress's intent to require EPA to establish NSPS for all pollutants emitted by a source category. Section 111(f) was inserted in response to EPA's prior challenges in promptly establishing NSPS for source categories listed under section 111(b). Under section 111(f), Congress placed EPA on a timetable to complete a specified number of delinquent NSPS by dates certain. To determine which categories should be dealt with first, Congress gave EPA three factors to consider:

> (A) the quantity of air pollutant emissions which each such category will emit, or will be designed to emit;
> (B) the extent to which *each such pollutant* may reasonably be anticipated to endanger public health or welfare; and
> (C) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new sources standards of performance

EPA must, likewise, consider "any" air pollutant emitted by a source when it reviews an existing NSPS. Section 111 provides that EPA "*shall*, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards."[369] Accordingly, if in EPA's judgment a category of sources "causes, or contributes significantly to" emissions that result in air pollution that may be reasonably anticipated to endanger public health or welfare, the Act requires EPA to add the category to a list, issue standards of performance applicable to that category, and review such standards on a prescribed schedule. Section 111 therefore creates an explicit, time-bound requirement for periodic review and updating of the performance standard for each category of stationary sources for all emitted air pollutants.

EPA must, in short, every eight years, (1) review its standards (as it has done here), (2) determine whether it is "appropriate" to revise them, including whether it is appropriate to add additional pollutants to the standards, and (3) if so, revise them accordingly. Again, because Congress intended EPA to reach each and any pollutant emitted by a regulated source category, this review must encompass all pollutants emitted by that source category.

EPA has long interpreted this "appropriateness" determination to turn on two (and just two) factors: (1) the amount of emissions of a given pollutant from that source category and (2) the availability of demonstrated control measures.[370,371] As EPA explained in its recent NSPS for the cement industry: "We have historically declined to propose standards for a pollutant where it is emitting in low amounts or where we determined that a BDT analysis would result in no control *National Lime Assoc'n v. EPA,* 627 F.2d at 426."[372,373] In 1985, for example, EPA decided not to revise the cement kiln standards to regulate NO_x and SO_2 emissions, based on the absence of demonstrated control technology.[374] By 2010, however, EPA found that circumstances had changed such that

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Congress thus ordered EPA to focus upon "each" pollutant emitted by these sources. Because section 111(f) standards are no different than any other NSPS – the section merely required EPA to complete unfinished standards – Congress's focus on "each" pollutant emitted by tardy sources speaks to section 111 generally, demonstrating that Congress, indeed, intended EPA's standards to control *each* pollutant emitted by such sources.

[369] *Id.* (emphasis added).

[370] *See, e.g.*, 50 Fed. Reg. 36,959, 36,961 (Sept. 10, 1985) (making negative determination based on lack of demonstrated control technology), attached hereto as Exhibit 128; 75 Fed. Reg. 54,994–95 (Sept. 9, 2010) (making positive determination based on significant emissions and existence of demonstrated control technology), attached hereto as Exhibit 129.

[371] *See also Nat'l Lime Ass'n v. EPA*, 627 F.2d at 426 n. 27 (discussing these factors)

[372] 75 Fed. Reg. 54,970, 54,996-97 (Sept. 9, 2010), attached hereto as Exhibit 129

[373] *See, e.g.*, 41 Fed. Reg. 3,826, 3,827 (Jan. 26, 1976) (finding that carbon monoxide and SO_2 standards were not appropriate for aluminum smelters because technology was not demonstrated (SO_2) and emissions were insignificant (CO)), attached hereto as Exhibit 130.

[374] 50 Fed. Reg. 36,959, 36,961.

it was now appropriate to set standards for NOx and SO_2 because cement kilns emitted substantial quantities of each pollutant and demonstrated control technologies were available[375]

Thus, inherent in EPA's duty to review the oil and gas NSPS is the duty to determine, with regard to "any" air pollutant emitted by the industry, whether it was "appropriate" to regulate that pollutant. This determination, again, turns on whether the pollutant is emitted in more than *de minimis* quantities and whether control technology is available.

EPA here has failed to carry out this duty with regard to methane, particulate matter, hydrogen sulfide, and nitrogen oxides. For each of these pollutants, it has either made an unlawful decision not to regulate, or unlawfully and unreasonably omitted any consideration of the issue. It must correct these errors.

A. EPA Must Regulate Methane

1. The Clean Air Act Requires EPA to Promulgate NSPS for Methane

Methane is a potent greenhouse gas that contributes to climate change. The Supreme Court recently found that methane comes within the broad scope of the Act's definition of "air pollutant" as defined under the Act, 42 U.S.C. § 7602(g), stating: "On its face, the definition embraces all airborne compounds of whatever stripe, and underscores that intent through repeated use of the word 'any.'" *Massachusetts v. EPA,* 549 U.S. at 529. As a result, EPA has explicitly found that methane is a component of an air pollutant that endangers public health and welfare within the meaning of the Clean Air Act.[376]

EPA acknowledges, as it must, that the oil and gas sector "emit[s] significant amounts of methane" – the equivalent of 251.55 million metric tons of CO_2 according to EPA's most recent inventory.[377] Indeed, EPA has identified the oil and gas industry as the "single largest contributor to United States anthropogenic methane emissions."[378] These emissions make the industry the second largest stationary source of greenhouse gas pollution in the country, and the largest single industrial source of methane pollution. Control technologies for methane are readily available. EPA's decision not to regulate a major category of emissions of this potent greenhouse gas therefore is illegal.[379]

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[375] 75 Fed. Reg. 54,994–95.

[376] *Endangerment and Cause or Contribute Findings for Greenhouse Gases*, 74 Fed. Reg. 66,496, 66,516 (Dec. 15, 2009) ("Endangerment Finding")

[377] 76 Fed. Reg. at 52,756.

[378] 76 Fed. Reg. at 52,792 (citing U.S. EPA, 2011 U.S. GREENHOUSE GAS INVENTORY REPORT EXECUTIVE SUMMARY (2011)) .

[379] Though it discussed a different industry – fossil-fuel fired power plants – the Supreme Court recently recognized that the NSPS program is an appropriate mechanism for regulating CO_2, another greenhouse gas. *See AEP v. Connecticut*, 131 S.Ct. 2527, 2537-38, __ U.S. __ (2011), attached hereto as Exhibit 131, ("We think it equally plain that the Act 'speaks directly' to emissions of carbon dioxide from the defendants' plants. . . . Once EPA lists a category, the agency must establish standards of performance for

EPA offers no reasonable rationale for its failure to set standards for methane. It says only:

> Although this proposed rule does not include standards for regulating the [methane] emissions discussed above, we continue to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.[380]

This rationale, such as it is, cannot be squared with either the statute or EPA's regulatory practice.

EPA cannot decline to complete its review duty, nor defer making an appropriateness finding. As we explain above, section 111 requires EPA to "at least every 8 years" review and, "if appropriate" revise its standards.[381] EPA must, on this review, make a final appropriateness finding, and either include methane or determine it is not appropriate to do so. It cannot delay its decision because the NSPS are designed to force pollution controls, and concomitant air quality improvements, on a statutorily-mandated timeline.

Thus, for purposes of completing its mandatory review duty as set forth above, EPA has made an affirmative decision *not* to regulate methane that both fails to apply the agency's own criteria for determining whether such a revision is appropriate, and runs directly counter to the evidence in the record. Again, EPA, as a matter of long-settled practice, has interpreted the "appropriateness" finding to turn on only two factors – the quantity of pollutant emitted and whether control technology exists to control that pollution. It cannot alter this long-standing statutory interpretation without rulemaking, and it has issued no proposal to do so. Thus, EPA is bound by its own interpretation. *See, e.g. Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 41 (1983).

On that interpretation, EPA can make only a positive appropriateness finding. The agency itself concedes that "processes in the Oil and Natural Gas source category emit significant amounts of methane." 76 Fed. Reg. at 52756. Indeed, this industry is

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emission of pollutants from new or modified sources within that category. § 7411(b)(1)(B); *see also* § 7411(a)(2). And, most relevant here, § 7411(d) then requires regulation of existing sources within the same category [unless sources of the pollutant in question are regulated under the national ambient air quality standard program, §§7408-7410, or the HAP program, § 7412].").

[380] 76 Fed. Reg. at 52,756.

[381] 42 U.S.C. § 7411(b)(1)(B).

responsible for over 40% of total U.S. methane emissions.[382] This amounts to 5% of all carbon dioxide equivalent (CO_2e) emissions in the country.[383]

Moreover, in describing why it chooses not to regulate methane, EPA acknowledges that technology exists that that would enable an emission limit for methane.[384] Indeed, there are numerous demonstrated control technologies for regulating methane from the oil and gas industry that consistent BSER, many of them endorsed or developed by EPA itself through its Natural Gas STAR and Methane to Markets programs.

These control technologies not only substantially reduce emissions, but also in many cases produce profits for industry.[385] EPA has recognized that the control technologies it has proposed for VOCs will indirectly reduce baseline methane emissions for the oil and gas sector by 26%.[386] EPA also predicts industry will make $45 million annually by implementing the rules.[387] For example, EPA notes that the ability to sell natural gas captured by using the proposed equipment and work practices for "green completions" would produce a net *savings* of $99 per ton of VOC reduced.[388] Moreover, according to EPA, the climate co-benefits of the methane reductions amount to as much as $1.6 billion by 2015.[389]

Finally, EPA's statement that many of its VOC controls will also yield *de facto* methane reductions, though true, is beside the point. Not only does this assertion have nothing to do with the appropriateness factors, it also ignores the fact that methane and the VOCs which EPA *has* regulated do not overlap in ways that ensure reliable and complete methane controls. The pollutants are emitted in different ratios from various devices and sources, and so simply are not interchangeable. Further, as discussed above, some measures that EPA has rejected as having unreasonable control costs for VOC reduction, have reasonable costs when the value of methane reductions is considered.

In short: Methane is emitted in significant amounts by sources in this industry even though there is control technology readily available to reduce such emissions. Moreover, EPA has already determined that methane, an air pollutant under the Act, endangers public health and welfare.[390] Based on the plain language of section 111,

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[382] *See* 76 Fed. Reg. at 52,756, 52,791-92; *see also* EPA, Sources and Emissions/Methane, *available at* http://www.epa.gov/outreach/sources.html, attached hereto as Exhibit 132.
[383] *Id.* at 52,791–92 (citation omitted).
[384] *See* id. (explaining that some methane reduction will occur because "many of the proposed requirements for control of VOC emissions also control methane emissions").
[385] *See, e.g.*, MEGAN WILLIAMS & CINDY COPELAND, METHANE CONTROLS FOR THE OIL AND GAS PRODUCTION SECTOR at 1 (2010) (submitted to EPA under separate cover on November 23, 2010)at 1.
[386] 76 Fed. Reg. at 52,792.
[387] 76 Fed. Reg. at 52,791.
[388] 76 Fed. Reg. at 52,758.
[389] *Id.* As our discussion above indicates, these benefits may be even larger.
[390] 74 Fed. Reg. at 66,516, attached hereto as Exhibit 134.

EPA is required to include methane standards in the final rule NSPS for new and modified sources from oil and natural gas operations, as well as standards under section 111(d) for existing sources of methane within the industry.

2. EPA's Failure to Regulate Methane is Unreasonable

While section 111 requires EPA to regulate methane emissions from oil and natural gas operations, to the extent EPA possesses any discretion in the matter, its decision not to regulate methane in this rulemaking is an abuse of such discretion and must be corrected in the final rule or a supplemental rule. EPA has not attempted to justify its decision not to regulate methane emissions in the proposed rule, except to say that it "continue[s] to assess these significant emissions and evaluate appropriate actions for addressing these concerns."[391] This "justification" is not just unlawful, but unreasonable.

First, it bears repeating that EPA's standards, as proposed, fail to capture the lion's share of methane emissions from the industry. EPA estimates that co-benefit methane reductions from its rules will amount to about 26% of the industry's methane emissions.[392] The remaining 74% of methane (much, but not all, of it from existing sources) goes uncontrolled. Moreover, even the 26% reduction that EPA cites is not enforceable, as it arises only incidentally from VOC reductions.

Given the demonstrated cost-effective nature of the control technologies for regulating methane, EPA could go much further to capture a large percentage of the remaining 74% of methane emissions left on the table with this rule. As noted above, the varying ratios of VOC to methane of various devices and sources in the gas industry mean that VOC regulations cannot serve as a surrogate for methane controls. Opportunities for EPA to achieve additional methane reductions are summarized below and explained in detail in the attached report by Megan Williams and Cindy Copeland.

Moreover, failing to directly regulate methane emissions also poses serious threats to public health and welfare: Methane, as we have explained, is a potent greenhouse gas, causing climate change that will threaten public health and welfare, as EPA recognized in its Endangerment Finding. Methane contributes significantly to ozone formation.[393] In order to protect the public by ensuring substantial, enforceable methane reductions, EPA must promulgate standards to control both of these pollutants at all sources.

Finally, EPA's decision not to regulate a major category of emissions of this potent greenhouse gas is simply bad policy. Based on EPA's own estimates, the oil and gas sector within the U.S. is responsible for over 40% of the country's total methane

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[391] 76 Fed. Reg. at 52,756.
[392] *Id.* at 52,792.
[393] *See, e.g.*, *id.* at 52,791.

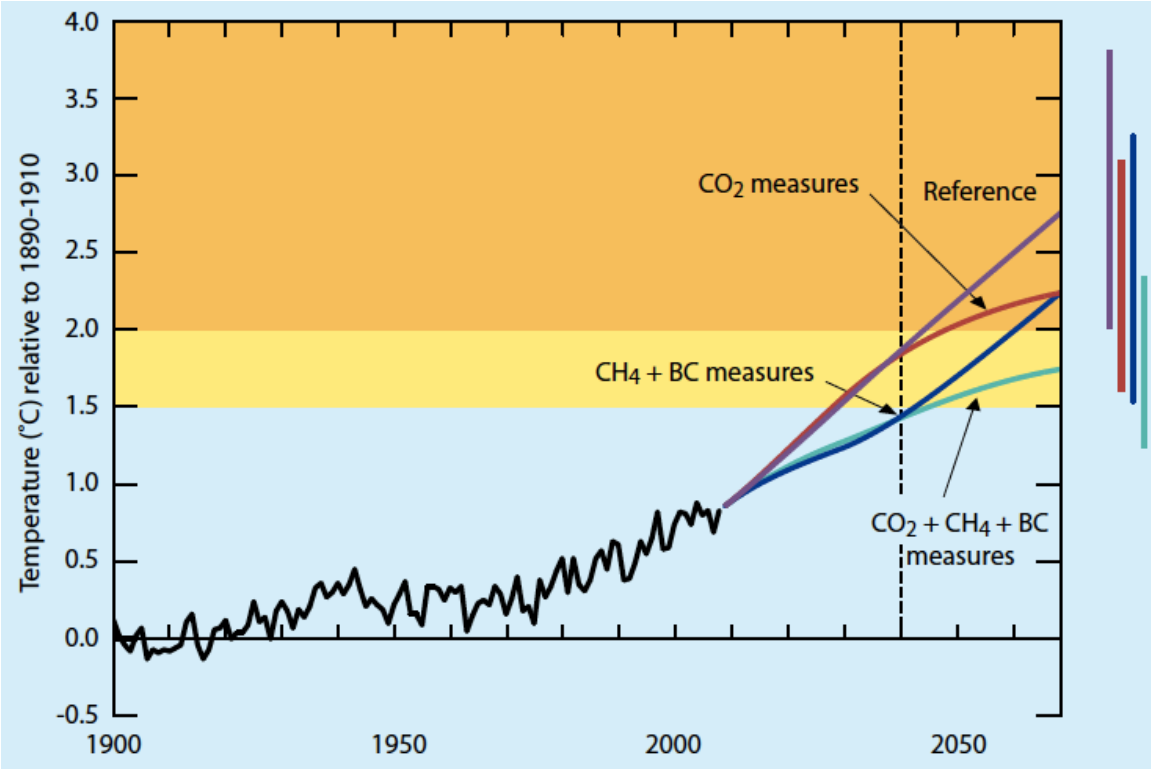
emissions.[394] Though the proposed rule will result in some reductions in methane emissions as an indirect byproduct of regulating VOC emissions, significant amounts of methane emissions will continue uncontrolled. Control technology that represents BSER within the oil and natural gas sector is available for capturing these emissions. While we commend EPA on its efforts to reduce VOC emissions, the Clean Air Act and EPA's own practices require the direct regulation of methane. The Agency's own finding that the greenhouse gas pollution of which methane is a part endangers human health and welfare demonstrates the significance of failing to regulate significant sources of methane

Methane is a potent greenhouse gas that contributes to climate change. As EPA explains in the proposed rule, "once [methane is] emitted into the atmosphere, [it] absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change."[395] Methane also reacts in the atmosphere to form ozone, which increases global temperatures.[396] Methane has 25 times the global warming potential of carbon dioxide over a 100 year time frame, and 72 times the global warming potential of carbon dioxide over a 20-year time frame.[397] The impacts of warming cause by methane and other greenhouse gases include "increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity and sea level rise, among other impacts."[398]

Methane's climate potency and short lifetime makes controlling methane emissions now particularly critical. While reductions of carbon dioxide emissions are essential to mitigate climate change, CO_2 *already emitted* will continue to warm the climate at dangerous rates and to dangerous levels (due to it's long lifetime in the atmosphere) if other climate warmers with shorter lifetimes are not addressed. Figure XX, from the recent UNEP report, illustrates how mitigating short-lived forcers (in this case both methane and black carbon (BC)) is an essential approach to reducing temperature rise in the coming decades. Reductions of BC and methane are essential to slow down rapid warming, *and* to reduce the peak of the warming. Conversely, if we allow methane emissions to continue to significantly increase (as they will do if the oil and gas industry is allowed to operate without a strong methane NSPS), those emissions will substantially increase the pace and severity of climate change.

Figure 5

[394] 76 Fed. Reg. at 52,756.
[395] 76 Fed. Reg. at 52,791.
[396] 76 Fed. Reg. at 52,791.
[397] IPCC 2007—The Physical Science Basis, Section 2.10.2.
[398] *Id.* at 52,791–92



Observed deviation of temperature to 2009 and projections under various scenarios. Immediate implementation of the identified BC and CH_4 measures, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative to pre-industrial levels. The bulk of the benefits of CH_4 and BC measure are realized by 2040 (dashed line).

Explanatory notes: Actual mean temperature observations through 2009, and projected under various scenarios thereafter, are shown relative to the 1890–1910 mean temperature. Estimated ranges for 2070 are shown in the bars on the right. A portion of the uncertainty is common to all scenarios, so that overlapping ranges do not mean there is no difference, for example, if climate sensitivity is large, it is large regardless of the scenario, so temperatures in all scenarios would be towards the high-end of their ranges.[399]

Methane's near term contribution to climate change is expected to have dire consequences on human health heat-related mortalities, the spread of infectious disease vectors, greater air and water pollution, and increase in malnutrition, and greater casualties from fire, storms and floods. Increased average temperatures are also expected to increase the number of heat waves.[400] This will have a particularly detrimental effect on vulnerable populations "such as those with heart problems, asthma, the elderly, the very young and the homeless."[401] Moreover, climate change is expected to play a role in worsening air quality problems that already impact human health through climate-induced increases in ozone and particulate matter levels.[402] Again, the vulnerable populations are expected to be impacted the most. Additionally,

[399] UNEP Report, Figure 3 at 12.
[400] EPA, *Climate Change, Health and Environmental Effects* (available at http://www.epa.gov/climatechange/effects/health.html) (last viewed Nov. 9, 2011)
[401] *Id*.
[402] *Id.*

the risk of contracting infectious diseases that are sensitive to climate, from malaria and yellow fever to tick-born Lyme disease, may increase with climate change.[403]

By failing to regulate methane, EPA is ignoring the recommendations of the Secretary of Energy's Advisory Board studying shale gas production. The Board recommended that regulators "expand immediately" efforts to reduce methane emissions using proven technologies.[404] The Government Accountability Office also recognized that requiring the oil and gas industry to control methane has numerous benefits, including (1) decreased greenhouse gas emissions, (2) economic benefits the industry by keeping more natural gas in the system for sale, and (3) for oil and gas development on federal lands, increased royalty payments to the federal government.[405]

B. EPA Must Regulate Particular Matter (PM)

EPA's proposed rule also fails to establish limits on particulate matter pollution from oil and gas development. Particulate matter is a "criteria pollutant" known to endanger public health and welfare. As discussed above, EPA has long evaluated whether it is "appropriate" to revise new source performance standards to include new pollutants based on (1) the amount of emissions from that source category, and (2) the availability of demonstrated control measures.[406] Both factors dictate regulation with respect to particulate matter from oil and gas development.[407] Yet, EPA does not even offer a rationale for failing to regulate this pollutant.

The first factor dictates regulation because oil and gas development is a major source of particulate matter. Particulate matter is produced during every phase of a drilling project. During road and well pad construction, particulate matter is generated by "equipment producing fugitive dust while moving and leveling earth" and by "vehicles generating fugitive dust on access roads."[408] Wind also kicks up particulate matter from

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[403] *Id.*

[404] SEAB Interim 90-Day Report, at 2.

[405] Government Accountability Office, "Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions," *Report to the Honorable Jeff Bingaman, Ranking Minority Member, Committee on Energy and Natural Resources, U.S. Senate*, July 14, 2004, attached hereto as Exhibit 135.

[406] *See, e.g.*, *Nat'l Lime Ass'n v. EPA*, 627 F.2d at 426 n.27.

[407] Section 111 applies broadly to categories of stationary sources including "any building, structure, facility, or installation which emits or may emit any air pollutant." 42 U.S.C. § 7411(a)(3). As the D.C. Circuit has recognized, this may include emissions from roads that are "constituent parts" of a stationary source. *See Ala. Power Co. v. Costle*, 606 F.2d 1068, 1079 (D.C. Cir. 1979), *superseded by Ala. Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979), attached hereto as Exhibit 136. In this case, EPA has defined the oil and natural gas sector broadly to include all "operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas." 76 Fed. Reg. at 52,744. Particulate matter pollution from construction of roads and well pads and vehicle trips necessary to drill for oil and natural gas and produce and distribute natural gas are encompassed within this definition.

[408] West Tavaputs FEIS at 4-16 to 4-17; *see also* BLM, *Revised Near-Field Air Quality Technical Support Document for the GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental*

well pads, dirt roads, and other disturbed areas susceptible to erosion.[409] Drilling and completion activities and subsequent well operations also require significant vehicle traffic, which generates additional particulate matter.[410] For example, trucks are necessary to transport fracking fluids, produced condensate, and water from storage tanks.[411] A 2008 study by the Utah Department of Transportation ("UDOT") estimated a range of 375 to 1,375 truck trips per well, depending on the depth of the well and its location.[412] That translated to 7,585 truck trips per day in the Uinta Basin during 2005-2006.[413] Similarly, in 2006, BLM predicted 851 round-trip truck trips for drilling and operation of each of the 3,100 wells approved by the Jonah Infill Drilling Project in Wyoming.[414]

Construction of wells and roads and vehicle traffic leads to considerable particulate matter pollution. For example, BLM estimates that natural gas operations on the West Tavaputs Plateau will generate more than 8,000 tons of fugitive dust each year from construction, drilling, and development activities and more than more than 1,800 tons each year from operations activities.[415] For the Gasco Energy Inc. Project in the Uinta Basin in Utah BLM estimates emissions of more than 4,000 tons of particulate matter each year.[416] In fact, road traffic associated with the extensive oil and gas development in Uinta County, Utah is expected to push PM_{10} concentrations to 99.7% of the NAAQS standard.[417]

The second factor relevant to EPA's determination whether to establish a standard of performance for particulate matter is also met because there are numerous methods

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Impact Statement, at 9, 17 (Apr. 2010) ("GASCO TSD") ("The major pollutant associated with development activities would be PM_{10} and $PM_{2.5}$ generated by earth-moving and traffic activities."), attached hereto as Exhibit 137; BLM, *Final Supplemental Environmental Impact Statement for the Pinedale Anticline Oil & Gas Exploration & Development Project*, at 4-74 (June 2008) ("Pinedale Anticline SEIS") (noting that particulate matter pollution would be produced by earthmoving equipment and vehicle traffic fugitive dust)

[409] *See, e.g.*, *Air Quality Impact Analysis Technical Support Document for the Pinedale Anticline SEIS*, at 9-11 (June 2008) (noting that substantial PM_{10} and $PM_{2.5}$ emissions would occur from construction of well pads and roads, traffic, and wind erosion)

[410] *See, e.g.*, *West Tavaputs FEIS* at 4-16 to 4-17.

[411] *See, e.g.*, *id.*

[412] *See* ENVIRON, *Oil and Gas Mobile Source Emissions Pilot Study: Background Research Report*, at 3-7 (June 2010) ("ENVIRON Report") (reviewing and summarizing UDOT's 2008 study, *Highway Freight Traffic Associated with Development of Oil and Gas Wells*), attached hereto as Exhibit 138

[413] *Id.* at 7.

[414] *Id.* at 19 (summarizing BLM's 2006 Jonah Infill Drilling Project Environmental Impact Statement).

[415] *See Near-Field Air Quality Technical Support Document for the West Tavaputs EIS*, at 44, 70 ("West Tavaputs TSD"), attached hereto as Exhibit 139.

[416] *GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental Impact Statement*, at 4-7 (Oct. 2010) ("GASCO DEIS"); *see also* ENVIRON Report, at 19 (noting that for the Jonah Infill Drilling Project BLM predicted nearly 4,000 pounds of fugitive PM_{10} per well from the unpaved road traffic necessary just for well completion testing); *id.* at 35 (noting that for drilling in the Little Snake Resource Management Area in Colorado BLM predicted tens of thousands of pounds of particulate matter from the traffic associated with each well pad or project).

[417] *See GASCO DEIS* at 4-27.

available to significantly reduce fugitive dust emissions. For example, application of water or other dust suppressants limits the amount of fugitive dust produced during construction and by vehicle traffic.[418] Watering haul roads can reduce particulate matter emissions by up to 95% during the first half hour after watering and by 74% during the three-to-four hours following watering.[419] Speed and traffic restrictions can also reduce particulate matter pollution from oil and gas vehicles.[420] Other control methods include minimizing road networks by clustering development, and designing and constructing roads with surface materials, drainage, and other characteristics to reduce erosion and sources of fugitive dust.[421] Prompt reclamation and vegetative surfacing of disturbed areas can further limit sources of fugitive dust.[422]

Given the significant amounts of particulate pollution from various stages of oil and gas development and the controls available to limit that pollution, the EPA must promulgate a new source performance standard pursuant to Section 111. EPA has established methods for estimating particulate matter emissions associated with oil and gas development, and could set control efficiencies for those emissions.[423] At a minimum, EPA must establish work practice standards that "reflect the best technological system of continuous emission reduction . . . adequately demonstrated."[424] For example, work practice standards could include requirements for operators to prepare a fugitive dust plan and mandate available control methods for the construction, use, and maintenance

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[418] *See* W.R. Reed & J.A. Organiscak, *Haul Road Dust Control: Fugitive Dust Characteristics from Surface Mine Haul Roads and Methods of Control*, at 4 (Oct. 2007) ("The use of water on haul roads is the most common dust control method used."), attached hereto as Exhibit 140; *see also* EPA, *AP-42: Compilation of Air Pollutant Emission Factors*, Ch. 13.2.2 at 10 (Nov. 2006) ("EPA AP-42") (wet suppression and other forms of surface treatments "increase[] the moisture content, which conglomerates particles and reduces their likelihood to become suspended when vehicles pass over the surface"), attached hereto as Exhibit 141; BLM, *Atlantic Rim Natural Gas Development Project Record of Decision*, at B-5 to B-6 (Mar. 2007) ("Atlantic Rim ROD") (operators required to apply water for dust abatement), attached hereto as Exhibit 142.

[419] *See* Reed & Organiscak, at 4.

[420] *See* EPA AP-42, Ch. 13.2.2 at 8 (vehicle restrictions to control fugitive dust include "lower[ing] the mean vehicle speed"); BLM, *Jonah Infill Drilling Project Record of Decision*, at B-16 (2006) ("Jonah Infill ROD") (requiring contractors and employees to obey speed limits, in part, to reduce fugitive dust concerns), attached hereto as Exhibit 143.

[421] *See, e.g.*, *Jonah Infill ROD* at B-14, B-16 (operators to conduct transportation planning "to identify the minimum road network necessary" and centralize infrastructure and operations); *Atlantic Rim ROD* at B-5 to B-6 (operators to control fugitive dust by "us[ing] appropriate road design including shape, drainage, and surface material to project road bed from being eroded"); AP-42, Ch. 13.2.2 at 10 (describing surface improvements that permanently alter the road surface to reduce fugitive dust emissions).

[422] *See, e.g.*, *Jonah Infill ROD* at B-17 (operators to expeditiously "establish plant cover" for disturbed areas).

[423] *See, e.g.,* AP-42, Ch. 13.2.2 at 4 (EPA equation for estimating fugitive dust emissions per vehicle mile travelled on unpaved surfaces based on surface material silt and moisture content, and mean vehicle weight and speed); BLM, *West Tavaputs Plateau Natural Gas Full Field Development Plan Record of Decision*, Att. 2 at 36 (July 2010) (condition of approval requiring a minimum of 50% control efficiency for particulate matter from well pad and road construction).

[424] *See* 42 U.S.C. § 7411(h)(1).

of all access roads and well pads.[425] Notably, any standard for application of chemical dust suppressants would require the EPA to assess associated "non-air quality health and environmental impact[s]."[426]

C. EPA Must Regulate Hydrogen Sulfide (H_2S)

Hydrogen sulfide (H_2S) is an extremely dangerous air pollutant which is emitted in significant quantities from the oil and gas industry. Although EPA has issued other Section 111 standards controlling H_2S, and control technologies are available to manage its emissions, EPA has failed to include H_2S in its proposed NSPS, or even to discuss the matter. It must correct this error.

1. Background on H_2S Exposure and Toxicity

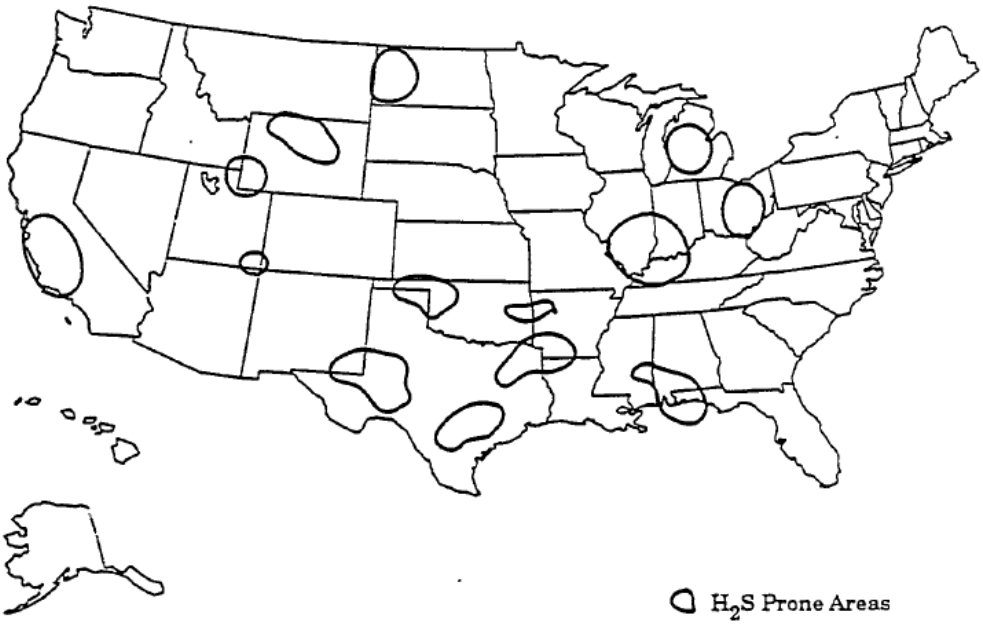
According to EPA, "H_2S is the most common impurity in hydrocarbon gases," and there are at least "14 major H_2S prone areas found in 20 states," including some fields where H_2S is 42% (by volume) of the gas produced.[427] The problem is national in scope, as this the figure below, taken from EPA's own report, demonstrates:

Figure 6

[425] *See, e.g.*, 74 Fed. Reg. 25,312-13 (May 27, 2009) (proposing work-practice standards for roads within coal-preparation operations, including a requirement for "fugitive dust plan[s]" that "require the owner/operator to pave the roads, wet the road surface, sweep up excess coal dust, or install tire washes to remove entrained dust to control PM emissions").

[426] 42 U.S.C. § 7411(h)(1). EPA's own internal report on chemical dust suppressants identifies several potential impacts, such as impacts to surface and groundwater quality, soil contamination, and toxicity to humans. Thomas Piechota et al., *Potential Environmental Impacts of Dust Suppressants: "Avoiding Another Times Beach,"* at v (2002), attached hereto as Exhibit 144. The report warns that chemical suppressants "should be avoided near sensitive environments, near water bodies and fractured rock, in areas with a shallow groundwater table, and other areas where water could quickly reach the saturation zone" and that "[s]ite specific characteristics should be considered when approving the use of dust suppressants." *Id.* at 17.

[427] *EPA Hydrogen Sulfide Report* at ii.



Source: Gas Research Institute. 1990.

Figure II-1. Major H_2S prone areas.

"Between 15 and 25 percent of natural gas in the U.S. may contain hydrogen sulfide."[428] There is substantial overlap between H_2S-prone areas and active oil and gas plays, meaning, according to EPA, that, with hundreds of thousands of wells at least potentially implicated in H_2S emissions, "the potential for routine H_2S emissions is significant."[429]

This potential is extremely concerning because hydrogen sulfide is toxic even at very low concentrations. The Agency for Toxic Substances and Disease Registry (ATSDR) has established a "minimal risk level" (MRL) – an "estimate of daily human exposure to a substance that is likely to be without an appreciable risk of adverse effects" – of 0.07 ppm for acute inhalation exposure to H_2S. ATSDR's intermediate-duration inhalation MRL is 0.02 ppm. EPA, similarly, calculated a chronic reference concentration (RfC) – the threshold below which it would not expect deleterious effects over a lifetime of daily exposure – of 0.001 ppm (that is, 1 part per billion, or "ppb") [430] There is substantial evidence that long-term low-level exposure can cause significant community health problems. As one researcher summarized, these long-term effects are substantial, and are particularly severe in children:

[428] Skrtic Report at 6 (May 2006).
[429] EPA Hydrogen Sulfide Report at III-35.
[430] ATSDR, *Toxicological Profile for Hydrogen Sulfide* at 14, 153 (2006), attached hereto as Exhibit 145.

Kilburn and Warshaw (1995) investigated whether people exposed to sulfide gases, including H2S, as a result of working at or living downwind from the processing of "sour" crude oil demonstrated persistent neurobehavioral dysfunction. They studied 13 former workers and 22 neighbors of a California coastal oil refinery who complained of headaches, nausea, vomiting, depression, personality changes, nosebleeds, and breathing difficulties. Neurobehavioral functions and a profile of mood states were compared to 32 controls matched for age and educational level. The exposed subjects' mean values were statistically significantly different (abnormal) compared to controls for several tests (two-choice reaction time; balance (as speed of sway); color discrimination; digit symbol; trail-making A and B; immediate recall of a story). Their profile of mood states (POMS) scores were much higher than those of controls. Test scores for anger, confusion, depression, tension-anxiety, and fatigue were significantly elevated and nearly identical in both exposed residents and former workers, while the scores for controls equaled normal values from other published studies. Visual recall was significantly impaired in neighbors, but not in the former workers. Limited off-site air monitoring (one week) in the neighborhood found average levels of 10 ppb H2S (with peaks of 100 ppb), 4 ppb, dimethylsulfide, and 2 ppb mercaptans. On-site levels were much higher. The authors concluded that neurophysiological abnormalities were associated with exposure to reduced sulfur gases, including H2S from crude oil desulfurization…..

In a case report Gaitonde *et al*. (1987) described subacute encephalopathy, ataxia, and choreoathetoid (jerky, involuntary) responses in a 20-month-old child with long term (approximately one year) exposure to hydrogen sulfide from a coal mine. Levels of up to at least 0.6 ppm (600 ppb) were measured and levels were possibly higher before measurements started. The abnormalities resolved after the emission source ceased operation.

As part of the South Karelia Air Pollution Study in Finland (Jaakkola *et al*., 1990), Marttila *et al*. (1994) assessed the role of long-term exposure to ambient air malodorous sulfur compounds released from pulp mills as a determinant of eye and respiratory symptoms and headache in children. The parents of 134 children living in severely polluted (n = 42), moderately polluted (n = 62), and rural, non-polluted (n = 30) communities responded to a cross-sectional questionnaire (response rate = 83%). In the severely polluted area, the annual mean concentrations of hydrogen sulfide and methyl mercaptan (H3CSH) were estimate to be 8 µg/m3 (6 ppb) and 2 - 5 µg/m3 (1.4 – 3.6 ppb), respectively. The highest daily average concentrations were 100 µg/m3 (71 ppb) and 50 µg/m3 (36 ppb), respectively. The adjusted odds ratios (OR) for symptoms experienced during the previous 4 weeks and 12 months in the severely versus the non-polluted community were estimated in logistic regression analysis controlling for age and gender. The risks of nasal symptoms, cough, eye symptoms, and headache were increased in the severely polluted community, but did not reach statistical

> significance…. In addition, OEHHA staff noted that the highest percentages of children with symptoms were in the moderately polluted community, not in the severely polluted community. The authors concluded that exposure to malodorous sulfur compounds may affect the health of children. The odor threshold for methyl mercaptan of 1.6 ppb (Amoore and Hautala, 1983) indicates that it also likely contributed to the odor and probably the symptoms.[431]

The oil and gas industry offers ample opportunities for such exposures, as EPA explained in its 1993 study of its H_2S emissions:

> In the oil and gas industry, H_2S may be emitted or released during exploration, development, extraction, crude treatment and storage, transportation (e.g., pipeline), and refining. . . . Potential sources of emissions include flares/vapor incinerators, heater-treaters (an oil/water/gas separation device), storage tanks, equipment (valves, flanges, etc.), and both active and abandoned wells.[432]

Although direct monitoring data of H_2S emissions around oil and gas extraction sources is limited, the data that does exist suggest that these sources are substantial. North Dakota, for instance, reported 3,300 violations of an odor-based H_2S ambient air quality standard around wells in that state, likely due to incomplete combustion of H_2S in wellhead flares.[433] Community monitoring in 2011 around gas wells in the Four Corners region of New Mexico and Colorado, likewise detected H_2S in one sample at levels 185 times safe levels.[434]

2. EPA Must Regulate H_2S Under Sections 112 of the Clean Air Act, or, at the very least, Section 111

In view of these risks, EPA must use its Clean Air Act authority to control H_2S emissions from the oil and gas industry.

At present, EPA makes only limited use of that authority. Although H_2S is controlled from major sources under the Prevention of Significant Deterioration program, the oil and gas industry is otherwise largely regulated only to prevent large-scale, emergency releases of H_2S, under Section 112(r) of the Clean Air Act, 42 U.S.C. § 7412(r). This provision focuses on efforts to "prevent the accidental release" of H_2S, and is not a substitute for baseline technological standards, applicable to all sources in the industry, and designed to prevent *ambient*, and long-term exposures to lower levels of this pollutant.

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[431] James Collins & David Lewis, Report to CARB, *Hydrogen Sulfide: Evaluation of Current California Air Quality Standards with Respect to Protection of Children* (Sept. 1, 2000).
[432] *EPA Hydrogen Sulfide Report* at ii; *see also id.* at II-5 – II-11 (listing sources).
[433] *Id. at* III-35.
[434] Global Community Monitor, *Gassed! Citizen Investigation of Toxic Air Pollution from Natural Gas Development* at 21

Ultimately, H_2S must be re-listed as a hazardous air pollutant ("HAP") under Section 112 of the Act, and controlled under its standards. [435] Several of the commenting groups have so petitioned EPA, and EPA staff has independently recommended that result, writing that:

- [The EPA OAQPS] Workgroup recommends listing because:
  - H_2S emission tonnage would rank among highest of HAPs
  - In terms of toxic potency, H_2S would rank in the top third of HAPs
  - Both ambient monitoring and modeled exposures show significant exceedances of health benchmarks, chronic and acute
  - Investigations of multiple complaints have demonstrated adverse health effects associated with exceedances of health benchmarks
  - If listed, H_2S would likely rank among top 6 noncarcinogens in [the National-Scale Air Toxics Assessment]
- In combination, these data suggest a "reasonable" likelihood that H2S presents a threat of adverse human health effects for both chronic and acute exposures, and meets the requirements under 112(b)(2) to list.[436]

To date, EPA has not taken action on either this recommendation or upon the petitions before it. In the absence of such action, it is appropriate, and, indeed, necessary, for EPA to control H_2S under the Section 111 program, which, though not as well-suited as Section 112 for the task, is available and can be used immediately. By accepting as much, we of course do not abandon our continued view that Section 112 regulation is ultimately necessary.

H_2S meets both "appropriateness" criteria under Section 111. First, as described above, it is emitted in substantial quantities from the oil and gas industry, in fields across the country.[437] Second, control technologies are readily available, and are in use in the oil and gas industry. Vendors offer, for instance, membrane-based removal systems,[438] a

[435] Hydrogen sulfide was removed from the section 112 list, without explanation, by Congress after significant industry pressure; its removal continues to put public health and welfare at unacceptable risk. Nothing prevent EPA from correcting this problem by re-listing hydrogen sulfide.

[436] EPA OAQPS Sector Based Assessment Group, *Should Hydrogen Sulfide be a HAP?* at 23 (Sept. 2007), attached hereto as Exhibit 146.

[437] Significantly, in this regard, state regulations are not uniformly or adequately limiting these emissions. As EPA staff recently summarized, state rules are highly variable, and many states (including major oil and gas producers like Louisana, and states containing important new plays, like Ohio, lack H_2S standards entirely). *See id.* at 16. Although the presence or absence of state regulation does not bear on EPA's Section 111 regulations, it is notable that exposure risks are going uncontrolled in many regions at both the state and federal levels, and underlines the unreasonableness of EPA's failure to act.

[438] Membrane Technology and Removal, H_2S Removal from Natural Gas: Soursep (vendor offering wellhead bulk removal system), attached hereto as Exhibit 147.

wide range of amine-based removal systems to scavenge H_2S at wells and in tanks,[439] and compounds designed to prevent bacteria from producing H_2S.[440]

EPA moreover has demonstrated that it can regulate H_2S emissions from a wide range of sources under Section 111. EPA has promulgated several NSPSs which control either H_2S or "total reduced sulfur" (a catchall term that includes H_2S) including for pulp and paper mills and petroleum refineries – but not for gas processing plants or oil and gas production. The most significant of these standards are the Subpart J and Ja standards, which control emissions from new and modified petroleum refineries. EPA's sulfur standards bar flaring any fuel gas which contains more than 230 mg/dscm of H_2S, as a sulfur oxide control measure, 40 C.F.R. § 60.104(a)(1), and bars emissions of any gas from Claus sulfur recovery plants which is more than 300 ppm by volume of reduced sulfur compounds or more than 10 ppm H_2S.[441] The standards also require periodic H_2S monitoring.[442] Yet, the NSPS program does not control H_2S from oil and gas sector sources.

It is time for EPA to correct this omission. Because both Section 111 appropriateness factors are met, EPA must propose, and then finalize, H_2S standards covering each H_2S source in the oil and gas sector.

To the extent EPA believes it requires more data to issue such standards, it must issue a Section 114 information collection request gathering data from the industry. This information request is particularly important because much of our information about the industry's emissions is rooted in EPA's 1993 report to Congress on H_2S. That report was drafted long before the shale gas boom saw the industry expand substantially, including into many urban and heavily-settled semi-rural areas. Now, wells are being built throughout the Dallas-Forth Worth area, for instance, as well as in and around cities in Pennsylvania. Properly assessing the health impacts of this increasing interweaving of oil and gas development with dense settlement is critical to accurately understanding H_2S exposure risks. EPA must properly assess these risks, and, in view of these changed circumstances, cannot rely upon its earlier assessments to assert that ambient exposure to H_2S is limited. Without waiving any claim that EPA was required to collect such information in the context of this rulemaking in order to timely complete its review duties, we ask that EPA state, in the final rule, whether and when it will issue such an information collection request.

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[439] Weatherford, *Hydrogen Sulfide Control* (vendor offering amine-based removal system), attached hereto as Exhibit 148; Baker Hughes, *White Paper: Hydrogen Sulfide Management: Mitigation Options in Petroleum Refining, Storage, and Transportation* (discussing a wide range of solutions for reducing H_2S formation and venting in tanks), attached hereto as Exhibit 149

[440] Yara United States, *PetroCare* (vendor offering chemical compounds for use in well construction to prevent H_2S formation), attached hereto as Exhibit 150.

[441] 40 C.F.R. § 60.104(a)(2); 40 C.F.R. § 60.102a(f)(1)(ii).

[442] 40 C.F.R. 60.105(f).

D. EPA Must Regulate Nitrogen Oxides (NO_x)

As we discuss above, certain oil- and gas-field combustion sources, including heater-treaters, are major NO_x emissions sources. Heater-treaters, in fact, may become dominant NO_x emissions sources in many regions, because they are so numerous. EPA must regulate this source, and, hence, must regulate this pollutant.

Once again, it is "appropriate" to do so under Section 111. As we discuss above, heater-treaters emit significant amounts of NO_x, and these emissions are controllable. As a result, EPA must include appropriate NO_x regulations in the final rule.

V. EPA MUST REGULATE METHANE AND VOCS FROM EXISTING SOURCES

Although the emissions reductions secured by EPA's proposal are significant, they represent only a relatively small fraction of the industry's total air pollution, because they do not address the extensive network of existing sources. As a result, as we note above, EPA is capturing only about 26% of the total methane emissions from the industry, and is likely capturing roughly similar percentages of the VOC emissions.[443] Although the proposed NSPS achieves significant VOC reductions from new and modified sources, it fails to control emissions from non-well existing sources, aside from refractured wells, even though these emissions are substantial. EPA must issue standards under section 111(d) of the Clean Air Act to control these emissions.

Unless these existing sources are regulated, the industry will continue to be a major source of significant air pollution for years to come. For this reason, the Secretary of Energy's Advisory Board Shale Gas Production Subcommittee, charged by the President with developing recommendations to control the industry's impacts, directly called on EPA to regulate existing sources in this rulemaking, writing:

> On July 28th the U.S. EPA proposed New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants (NSPS/NESHAPs) for the oil and natural gas sector. The proposed rules, which are currently under comment and review, are scheduled to be finalized by April 3, 2012, represent a critical step forward in reducing emissions of smog-forming pollutants and air toxics. The Subcommittee commends EPA for taking this important step and encourages timely implementation. *However, the proposed rules fall short of the recommendations made in the Subcommittee's Ninety-Day Report because the rules do not directly control methane emissions and the NSPS rules as proposed do not cover existing shale gas sources except for fractured or re-fractured existing gas wells.*[444]

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[443] *See* 76 Fed. Reg. at 52,792.

[444] Shale Gas Production Subcommittee Second 90-Day Report (Nov. 18, 2011) at 5 (emphasis added), attached hereto as Exhibit 151.

EPA must correct this crucial gap. It is required to do so by statute, for both methane and VOC sources, as we explain below. Because much pollution from existing sources can be controlled using variations of the same methods EPA has already proposed for new sources in this rulemaking, such existing source standards can be developed and implemented quickly. After setting out EPA's legal obligations, we describe how such standards can and must be designed.[445]

A. EPA Must Regulate Existing Sources of Methane

We have already described why EPA must regulate methane from new and modified sources under Section 111(b): It is an abundant (indeed, the most abundant) pollutant from the oil and gas industry, and is readily controlled with available technology. Once EPA promulgates such new and modified source standards, it will be required to control existing sources as well, under Section 111(d) of the Act.

Section 111(d) of the Act provides that EPA "shall prescribe regulations" which establish a process, mirroring that for State Implementation Plans pursuant to section 110, under which states establish standards of performance for existing sources that emit certain pollutants.[446] These pollutants, referred to as "designated pollutants," 40 C.F.R. § 60.21(a) include:

> Any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 but (ii) to which a standard of performance under this section would apply if such existing source were a new source.[447]

Methane will be such a "designated pollutant" as soon as EPA issues 111(b) standards controlling it. This is because methane is, first, not a criteria pollutant (that is, it is not "on a list published under section 7408(a)" and EPA has not issued an air quality standard for it). Nor is methane a critical air pollutant "regulated under section 7412."[448] As a result, once "a standard of performance under this section" is

[445] We note the proposal does apply to some existing sources through its modification provisions. Specifically, we applaud EPA's proposal to define the completion and recompletion of a hydraulically fractured gas well as a modification. It appears from the preamble that other existing sources, including pneumatic controllers and centrifugal compressors, are also subject to the new source performance standards, in a manner of speaking, in that the NSPS dictates how they must be replaced. 76 Fed. Reg. at 52738, 52761-62. We agree that replacement of an existing source constitutes new construction and therefore requires compliance with the NSPS. The final rule language must clarify that replacement of any and all affected facilities triggers compliance with the NSPS.

[446] 42 U.S.C. § 7411(d)(1).

[447] 42 U.S.C. § 7411(d)(1).

[448] Although the statute refers to pollutants "emitted from a source category which is regulated under section 7412," EPA has made clear in its rules that this restriction on 111(d) applicability applies to

promulgated for the industry, regulating methane, methane will also be subject to Section 111(d) regulation.

Such regulation is implemented via a state-implementation-plan like process "under which each State shall submit to the Administrator a plan which establishes standards of performance for any existing source" of a designated air pollutant.[449] To speed this process, EPA sets forth standards of performance for these pollutants covering existing sources in "emission guidelines," which the states must then adopt.[450] Emission guidelines specify how the states shall reduce air pollution from existing sources that emit certain air pollutants to which a standard of performance would apply if such existing source were a new source.[451]

Like standards of performance for new sources, emission guidelines must reflect "Best Demonstrated Technology" and the "Best System of Emissions Reduction."[452] Emission guidelines can be tailored to the remaining useful life, of existing sources, as well as other relevant factors.[453] EPA "shall" issue such emissions guidelines for pollutants that are neither hazardous air pollutants listed under section 112 nor criteria pollutants listed under section 108.[454]

This process moves forward once EPA has promulgated Section 111(b) standards. EPA rules provide that "*[c]oncurrently* upon or after proposal of standards of performance for the control of a designated pollutant [from sources subject to an NSPS]," EPA "*will* publish a draft guideline document containing information pertinent to control of the designated pollutant from designated facilities [existing sources]," and "a final guideline document *will be published*" "*upon or after*" promulgation of standards of performance for new sources.[455]

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pollutants listed under Section 112, not every pollutant emitted from a Section 112 source category (as some of these pollutants may not be listed HAPs, but will still warrant control under other programs).

[449] 42 U.S.C. § 7411(d)(1).

[450] *See* 40 C.F.R. §§ 60.21(e) and 60.22.

[451] 42 U.S.C. § 7411(d)(1); 40 C.F.R. § 60.21(b) (defining facilities to which emission guidelines apply as those "which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility").

[452] 40 C.F.R. § 60.22(b)(5) (providing that guideline documents "will" include "an emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities…"). *See also* 40 C.F.R. § 60.21(e) ("Emission guideline means a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22(a), which reflects "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator determines has been adequately demonstrated for designated facilities.")). Of course, in situations where EPA has set a section 111(h) BTSER standard, existing source regulations must parallel this standard as well.

[453] 42 U.S.C. § 7411(d)(1); 40 C.F.R. § 60.22(b) (describing content of emission guidelines).

[454] *See* 42 U.S.C. § 7411(d)(1).

[455] 40 C.F.R. § 60.22(a) (emphases added).

Thus, EPA regulation of new and modified sources will trigger regulation of existing sources. This process will take time. Once a guideline document has been published, the states generally have nine months to submit their plans,[456] and the plans themselves may not become effective immediately for all sources. The longer EPA delays even proposing *new* source standards, the longer it will take to complete the existing source process, during which time approximately three-quarters of the industry's methane emissions will continue to go uncontrolled. EPA therefore must begin the process as soon as possible in order to timely address this major emissions source.

B. EPA Must Regulate Existing Sources of VOCs

Like methane, VOCs are "designated pollutants" for Section 111(d) purposes and EPA must promulgate existing source standards for them.

VOCs are designated pollutants because they are neither criteria pollutants nor hazardous air pollutants. For NSPS purposes, "Volatile Organic Compound" means, simply, "any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an alternative method, or which is determined by procedures specified under any subpart."[457] There are no 42 U.S.C. § 7408 criteria for VOCs so defined, and VOCs are not listed as section 112 HAPs.[458] Moreover, when EPA finalizes its current proposal, VOCs will be "subject to a standard of performance for new stationary sources" in the oil and gas industry.[459] As such, the plain language of the statute, and of EPA's implementing regulations,[460] renders VOCs designated pollutants.

Thus, once EPA finalizes its 111(b) standards, it must immediately move on to proposing and finalizing 111(d) standards for existing VOC sources.[461] Although the regulations provide that EPA must act "concurrently or thereafter," we urge EPA to offer proposed guidelines simultaneously with its final new source standards, to ensure that the process to control this major pollution source moves forward rapidly, and to provide the industry with a clear regulatory calendar.

Such progress is particularly important because existing facilities are such significant VOC sources. Although new and modified VOC sources emit a total of 2.24 million tons of VOC per year,[462] and, according to EPA, the proposed NSPS and NESHAP, acting

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[456] 40 C.F.R. § 60.23
[457] 40 C.F.R. § 60.2; *see also* Proposed 40 C.F.R. § 60.5430 (adopting the definitions in § 60.2 and in Subpart VVa); 40 C.F.R. § 60.481a (Subpart VVa, adopting the § 60.2 definition).
[458] *See* 42 U.S.C. § 7412(b)(1) (HAP list)
[459] See 40 C.F.R. § 60.21(a).
[460] *See* 40 C.F.R. § 60.21(a),
[461] 40 C.F.R. § 60.22(a).
[462] RIA at 3-1.

together, will reduce VOC emissions from these sources by 540,000 tons of VOC or more in 2015,[463] but existing sources account for a substantial portion of the remaining VOC inventory. While EPA does not include an estimate of the total amount of emissions from existing sources in the proposed rulemaking, estimates from others demonstrate such emissions are substantial. As Table 2 demonstrates, VOCs from existing sources in five basins in the Intermountain West are projected to equal 259,051 tons in 2012.[464] Without regulation to reduce emissions from existing equipment, these emissions will continue for many years.

Table 2

Oil & gas emissions source	**Denver-Julesburg basin**		**Uinta basin**		**Piceance basin**		**North San Juan basin**		**South San Juan basin**		**Wind River basin**	
VOC	2006	2010	2006	2012	2006	2012	2006	2012	2006	2012	2006	2012
Condensate tanks	53,510	53,109	6,195	21,719	3,405	1,895	0	0	3,964	3,790	710	519
Oil tanks	0	0	14,357	20,722	0	0	165	165	2,430	2,359	449	486
Dehydrators	506	332	19,470	30,665	2,929	2,371	14	10	11,372	10,896	1,324	1,010
Well blowdowns	1,744	2,207	292	460	2,172	2,444	0	0	13,145	12,595	2,018	1,861
Fugitives	8,024	10,498	1,910	3,212	1,330	1,871	0	0	4,137	4,631	296	415
Pneumatic devices & pumps	12,381	16,342	23,301	39,404	2,532	3,835	0	0	1,726	1,925	6,351	7,303

In short, if EPA developed standards for existing sources it would achieve substantial health and environmental benefits. It must do so.

We recognize, of course, that VOCs are also treated as ozone precursors, and that ozone is a criteria pollutant, which could not itself be regulated under Section 111(d). Although they are not defined as precursors for NSPS purposes, EPA's regulations governing the Prevention of Significant Deterioration program,[465] and those governing state implementation plans,[466] do so define them. Ozone is generally regulated

[463] 76 Fed. Reg. at 52,791.
[464] Western Regional Air Partnership Phase III *2006 and 2012 Activity Emission Estimates for the Denver-Julesburg, Piceance, Uinta, South San Juan, North San Juan, and Wind River Basins*, available at http://www.wrapair.org/forums/ogwg/PhaseIII_Inventory.html, attached hereto as Exhibit 152.
[465] *See* 40 C.F.R. §§ 51.15(a)(1)(xxxvii)(c)(1), 51.166(b)(49)(i), 52.21(b)(50)(i)(A).
[466] *See* 40 C.F.R. § 51.100(s)

primarily through state implementation plans implementing the National Ambient Air Quality Standards (NAAQS) for ozone, as directed by Section 108 of the Act and by the special ozone regulatory program in subpart 2 of part D of the Act, addressing ozone nonattainment areas.[467]

Although some commenters may argue that this precursor status precludes section 111(d) regulation of VOCs, this is not the case. Initially, as a purely textual matter, the statute simply does not refer to "precursors" to criteria pollutants themselves as included in the Section 111(d) ban. Nor do EPA's implementing regulations. So, to the extent that EPA has any authority to decline regulation of VOCs as 111(d) pollutants, that authority does not arise from section 111(d).

If EPA claims such authority, it could be found only in section 302, which provides that the term "air pollutant":

> [I]ncludes any precursors to the formation of any air pollutant, *to the extent* the Administrator has identified such precursor or precursors for the particular purpose for which the term "air pollutant" is used.[468]

Put differently, section 302, if anything, grants EPA the discretion to identify particular precursors and incorporate those substances into the definition of an "air pollutant" for particular regulatory purposes.

EPA has used this discretion previously. In a series of rulemakings implementing the PM 2.5 NAAQS, it explained that it would treat each PM 2.5 precursor distinctly for regulatory purposes because "the Administrator has discretion to identify which pollutants must be classified as precursors for particular regulatory purposes."[469]

Thus, nothing about section 302 obligates EPA to decline to regulate VOCs under section 111(d). On the contrary: section 302 authorizes EPA to identify distinct "particular purpose[s]" in its various regulatory definitions of precursor pollutants. The agency therefore need not treat VOCs the same way for section 111(d) regulation as it does for ozone NAAQS regulation, because in each instance, the regulations "address different aspects of the air pollution problem" caused by VOCs. Specifically, although sections 108 and 182 of the Act requires state implementation plans to include some control of existing sources of VOCs in ozone nonattainment areas, they do not extend to sources in attainment areas, and also do not necessarily reach every important source in each industry source category.[470] Section 111(d), by contrast, can reach existing sources of

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[467] *See, e.g.*, 42 U.S.C. § 7511.
[468] 42 U.S.C. § 7602(g).
[469] 73 Fed. Reg. 28,322, 28,326 (May 16, 2008) (final rule on using the PM 2.5 standards in the NSR program), attached hereto as Exhibit 153; 72 Fed. Reg. 20,586, 20,590-91 (Apr. 25, 2007) (Clean Air Fine Particle Implementation Rule, making the same points), attached hereto as Exhibit 154.
[470] *See* 42 U.S.C. § 7511a.

VOC pollution in attainment and in nonattainment areas, and can provide a uniform, clear regulatory standard for actors across the oil and gas industry, which is a major source of VOC pollution.

These distinct statutory purposes and distinct air pollution problems support treatment of VOCs as 111(d) pollutants, even were the plain language of the statute and regulations not so clear. Indeed, it would be unreasonable for EPA *not* to use its discretion to regulate VOCs under section 111(d).[471]

C. EPA Has Used Its 111(d) Authority to Functionally Regulate VOCs and Methane Before

Although EPA has not previously issued section 111(d) standards that explicitly control VOCs, its standards of performance for municipal solid waste landfills are, functionally, 111(d) VOC standards, and provide a useful model here.

Landfills are significant sources of methane, VOCs, and other pollutants. To address existing landfills, EPA promulgated 111(d) control guidelines concurrently with its new source performance standards. These guidelines are based upon a pollutant mixture of "non-methane organic compounds" (NMOC).[472] NMOC is 80% VOC by mass, so NMOC controls are fundamentally VOC controls, which happen to also control some non-VOC pollutants.[473,474] Likewise, though EPA, as a legal matter, excluded methane from regulation as part of "NMOC", methane is co-emitted with NMOC, meaning that NMOC controls reduce methane emissions as well as non-methane organic compounds.[475]

EPA emphasized the benefits of VOC and methane control (along with control of hazardous air pollutants co-emitted with NMOC at existing sources) in its rulemaking. As it explained:

> NMOC includes [VOC], hazardous air pollutants (HAPs), and odorous compounds. VOC emissions contribute to ozone formation which can result in adverse effects

[471] It is true that EPA has once declined to use its 111(d) authority to regulate VOCs in its 2007 NSPS for VOC leaks from synthetic chemical manufacture and refineries (subpts. VV, VVa, GGG, and GGGa), 72 Fed. Reg. 64,680, 64,868 (Nov. 16, 2007), attached hereto as Exhibit 155. It did so without detailed explanation or analysis, however, and is free to change that position by rulemaking here, particularly in view of the industry's extraordinarily high VOC emissions.

[472] 61 Fed. Reg. 9,905, 9,905 (Mar. 12, 1996) (final 111(d) standards); 40 C.F.R. §§ 60.751 & 60.754 (regulatory NMOC definition), attached hereto as Exhibit 156.

[473] *See* 61 Fed. Reg. at 9,912 (stating that NMOC emissions of 50 tpy "correspond[] to a VOC emission rate of 40 tpy.").

[474] See also EPA, Municipal Solid Waste Landfill New Source Performance Standards (NSPS) and Emissions Guidelines (EG)—Questions and Answers (1998) at 19 (explaining that "NMOC is non-methane organic compounds, which include volatile organic compounds (VOC) as well as other organic compounds"), available at http://www.epa.gov/ttnatw01/landfill/landfq%26a.pdf, attached hereto as Exhibit 157.

[475] Of course, as discussed above, we do not agree with EPA's failure to regulate methane here.

> to human health and vegetation. Ozone can penetrate into different regions of the respiratory tract and be absorbed through the respiratory system. The health effects of exposure to HAPs can include cancer, respiratory irritation, and damage to the nervous system. Methane emissions contribute to global climate change and can result in fires or explosions when they accumulate in structure on or off the landfill site . . . . Today's rules will serve to significantly reduce these potential problems with [landfill gas] emissions.[476]

EPA further specified the benefits of reducing existing source emissions of VOCs and methane in its proposed rule, listing five benefits: (1) reduced ozone formation; (2) incidental control of HAPs; (3) managing the "well-documented danger of fires and explosions"; (4) controlling unpleasant odors; and (5) reducing the severity of global climate change.[477]

To address these harms, EPA issued 111(d) standards embracing all large existing landfills,[478] requiring them to install emissions control systems that collect and destroy escaping landfill gas.[479] These standards, which covered hundreds of existing landfills,[480] halved NMOC emissions from those sources, and reduced methane emissions by about 40%.[481]

EPA can and must take several lessons from this experience:

First, as discussed above, EPA has authority to set and direct section 111(d) standards for VOCs although VOCs are precursors of the 108 pollutant ozone. VOCs are an important precursor to ozone, a listed 108 pollutant. Without 111(d) regulation, not all important existing sources of these precursor pollutants will be subject to emissions controls. For instance, although section 182 of the Act requires state implementation plans to include some control of existing sources in ozone nonattainment areas, it does not extend to sources in attainment areas, and also does not necessarily reach every important source in each industry source category.[482] Section 111(d) is thus an important adjunct to controlling these existing sources. In the landfill standard, EPA took this view. Although EPA opted to regulate VOCs as part of NMOC, this distinction is not practically important, whatever its legal significance: NMOC controls regulate VOCs, and

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[476] 61 Fed. Reg. at 9,905-06. *See also* 56 Fed. Reg. 24,468 (May 30, 1991) (proposed rule), attached hereto as Exhibit 158.
[477] *Id.* at 24,472-75.
[478] We do not take a position here as to the appropriateness of EPA's emissions threshold decisions for landfills.
[479] 61 Fed. Reg. at 9,907-9,908.
[480] *Id.* at 9,914.
[481] *Id.* at 9,908-9.
[482] *See* 42 U.S.C. § 7511a.

the regulation is founded on these benefits.[483] EPA could just as readily have regulated VOCs alone.

Second, section 111(d) controls may incidentally control hazardous air pollutants, or criteria pollutants. Although section 111(d) may not be relied on to *satisfy* section 112 requirements due to the differing statutory requirements between the two programs, regulations targeted at non-HAPs may produce important HAP co-benefits, but the existence of those co-benefits does not eliminate the requirement to directly regulate the pollutant in question. Thus, though landfill gas contains several HAPs,[484] and regulating NMOC would help reduce their emissions, EPA did not view this benefit as an impediment to section 111(d) regulation. Instead, it emphasized HAP control as an important additional benefit to section 111(d) control.[485]

Third, section 111(d) regulations for existing sources can be designed to rapidly produce significant emissions reductions. The landfill standards were designed to reduce NMOC emissions by 7 million megagrams in the first four years of their operation.[486]

Oil and gas production sources offer similar opportunities. Once again, EPA has the opportunity of regulating a class of existing sources whose emissions are cumulatively large. Existing source controls would produce all five of the benefits EPA identified for its earlier landfill section 111(d) rules, as controlling VOCs would reduce VOC and methane emissions, along with some HAP emissions.[487] And, once again, existing sources can readily adopt cost-effective controls (and, in fact, already do so as set forth elsewhere in these comments). We outline some of these potential controls below.

D. Design Approaches for a Section 111(d) Standard for VOC and Methane

Like standards of performance for new sources, emission guidelines must reflect "Best Demonstrated Technology."[488] New source standards are the starting point for existing source standards, but those rules may be modified to "take into account the remaining useful life of the existing sources to which such standard applies."[489]

Many of the standards EPA has proposed for new sources can be readily and cost-effectively applied to existing sources without losing rigor, as demonstrated by the standards in place in Wyoming and Colorado for storage vessels, gas processing plants

[483] 61 Fed. Reg. at 9,906.
[484] 56 Fed. Reg. at 24,474
[485] *Id.*
[486] *Id.* at 9,908.
[487] *See* RIA at 4-18 – 4-35.
[488] 40 C.F.R. § 60.22(b)(5).
[489] 42 U.S.C. § 7411(d)(1); *see also* 40 C.F.R. § 60.24(c) (providing that 111(d) standards generally "shall be no less stringent than the corresponding emission" standards for new sources).

and pneumatic devices, described above.[490] Similar approaches could be used to control methane and VOCs for each facility type, so we sketch these design principles for both pollutants, recognizing that separate regulations must be promulgated for each pollutant in order to fully regulate these sources. We discuss each facility type in turn.

Notably, although the same general *technology* can control methane and VOCs, allowing us to describe these standards jointly, these technologies will not necessarily be *applied* across the sector – and nor can their use be enforced -- unless EPA issues section 111(d) standards for both VOCs and methane. This gap occurs, as we have explained above, because VOCs and methane are not co-emitted in equal proportions across the sector. Instead, the proportion of methane to VOC emissions grows steadily as gas moves from the wellhead to the distribution sector, meaning that VOC standards are unlikely to operate rigorously further down the production chain, and that, as a result, methane-specific controls are needed to fully achieve the existing source benefits we describe below.

1. Standards for Existing Pneumatic Devices

Pneumatic devices in the production sector are responsible for 17% of production sector emissions emitting 67 Bcf of methane annually. Pneumatics in the transmission sector emit another 12 Bcf.[491] Because methane is co-emitted with VOCs, these controllers are also significant VOC sources. According to EPA, a single year's worth of new bleed devices (about 17,000 controllers) will emit 32,739 tons per year of VOCs, along with 117,766 tons of methane.[492] New controllers, however, are only a small fraction of the existing population of controllers. The latest EPA GHG Inventory estimates that 564,842 pneumatic controllers exist in the production, processing, transmission and storage sectors as of 2009.[493] Using EPA's estimates of the percentage of existing controllers that are high versus low or no-bleed, approximately 243,976 and 27,481 high-bleed controllers existed in 2009 in the production and transmission/storage sectors respectively.[494] This existing population emits 556,373 tons of VOCs annually. Applying EPA's assumption that 80% of high-bleed devices can be replaced with low or no-bleed devices, a 111(d) standard that requires replacement of high-bleed controllers would

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[490] Elsewhere in these comments, we discuss ways that the new source standards should be improved. We expect that corresponding improvements would also appear in the proposed existing source standards.

[491] Copeland & Williams Report at 32-33.

[492] EPA, TSD at 5-10.

[493] EPA, *Inventory of U.S. Greenhouse Gases and Sinks (1990-2009), April 2011*, Table A-120, p. A-149, http://epa.gov/climatechange/emissions/usinventoryreport.html. This is a more recent estimate than that provided in the TSD which estimates the pneumatic controller population for 2004 to be 498,000. TSD, 5-1. We refer here to the estimate of existing source population contained in the Inventory because it is more recent and also because it breaks out the number of controllers per industry segment (i.e.: production, processing and transmission).

[494] EPA estimates the number of bleed devices in the production and transmission sectors to be 51% and 32%, respectively. TSD at 5-7

thenceforth annually remove approximately 1,288,195 tons of methane and 351,326 tons of VOCs from the atmosphere from the production sector and 6,508 tons of methane and 1,759 tons of VOCs from the transmission/storage sector.[495] Since these figures represent the existing population as of 2009, the actual pollution reductions are likely much greater since oil and gas production has increased since 2009. EPA could, therefore, achieve significant benefits by applying controls to existing pneumatics.

The proposed new source controls provide a useful model. As proposed, the rules define each affected facility as a "single pneumatic controller."[496] As a result, each new controller must meet the performance standards, which generally require no-bleed valves at processing plants, and low-bleed controllers elsewhere.[497] As a result, replaced controllers must be no or low-bleed.[498] Given enough time, as old controllers wear out, this requirement will therefore gradually cause the entire population of controllers to turn over.

But without 111(d) standards, replacing the existing collection of controllers will take a great deal of time. EPA estimates pneumatic controllers have a ten-year expected lifetime for amortization purposes, but controllers may last even longer in practice – and EPA has developed no data showing otherwise.[499] Existing source standards could usefully accelerate replacement of polluting controllers.

Therefore EPA must set emissions standards which drive operators to timely replace their existing controllers with no-bleed controllers or (if no-bleed controllers cannot be used), low-bleed controllers in a timely fashion. These replacements are highly likely to be cost-effective. EPA determined that, thanks to increased natural gas capture from replacement devices, its new source controller standards will generate annualized net savings of $1,159 per controller in the production sector, and costs of only $23 per controller in the transmission and storage sector.[500] Because these estimates *already* include the costs of replacing controllers at existing sources where sources voluntarily undertake replacement, EPA can be sure that such replacements are both feasible and cost-effective.

Notably, Colorado and Wyoming have reached similar conclusions regarding the efficacy and cost-effectiveness of replacing high-bleed devices with low or no-bleed ones. Colorado requires that, "when new, replaced, or repaired pneumatic devices are

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[495] TSD at 5-12 (assuming 80% of high-bleed controllers can be retrofit as low or no-bleed)
[496] Proposed 40 C.F.R. § 60.5365.
[497] Proposed 40 C.F.R. § 60.5390.
[498] *See id.*
[499] TSD at 5-16.
[500] RIA at 3-15. Note that the net positive cost in transmission and storage, in contrast to the negative cost in the production segment, arises because pipeline firms typically do not own the gas conserved with no-bleed or low-bleed controllers (since they do not own the gas in their pipelines). We believe that the industry as a whole, therefore, will save money from installation of less wasteful controllers.

installed, low or no bleed valves must be used, where technically feasible,"[501] and Wyoming requires all new and modified controllers to be low or no-bleed.[502] Moreover, in certain ozone non-attainment areas, Colorado also requires all high-bleed pneumatic controllers to "be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic compressor". Colorado required such replacements within months of the time the regulation was promulgated.[503] Colorado determined that such retrofits were highly cost-effective, resulting in savings of $747 per controller including gas savings.[504]

To be sure: although replacement costs are either negative or very small, there may well be nontrivial labor and logistics costs associated with replacing the entire population of existing controllers on an accelerated schedule. EPA could reflect that logistical challenge by designing the existing source standard around the "remaining useful life" of these devices, staggering or extending a replacement requirement to reflect instrument failure rates and repair frequencies. For instance, an existing source standard might require that all existing controllers be replaced within three years or some other reasonable period, allowing for a manageable compliance period. Alternately, EPA might further calibrate a replacement time period by comparing replacement costs with the cost savings resulting from a new no-bleed or low-bleed controller, and then setting the replacement period at the point at which, on average, savings from a new controller balance out the labor costs of an early replacement. Finally, EPA might simply seek to take advantage of repair visits to existing facilities, and specify that, when a facility is visited for planned maintenance; existing controllers are to be replaced at the same time as other work is to be done.

Whichever of these options EPA ultimately proposes and evaluates, the core concern is the same: The existing fleet of controllers is a significant methane and VOC source. If EPA accelerates the replacement frequency for these devices, the public will capture major emissions benefits –controlling just new devices would reduce VOCs by 90,685 tpy and achieve equally significant methane benefits. Swiftly replacing existing devices will yield far greater reductions.

2. Standards for Existing Compressors

EPA estimates suggest that there are over 12,000 existing reciprocating compressors[505] and 1,400 existing centrifugal compressors.[506] Leaks from these compressors make

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[501] Co. Oil and Gas Conserv. Commission Rule 805(b)(2)(E), attached hereto as Exhibit 159.
[502] Wy. Dept. of Envt'l Quality, *Oil and Gas Production Facilities* (Mar. 2010) at 10, attached hereto as Exhibit 160.
[503] Co. Department of Public Health and Environment Regulation 7, XVIII.C.2 (promulgated Dec. 12, 2008. High-bleed controllers had until May 1, 2009 to comply), attached hereto as Exhibit 161.
[504] Revised final Economic Impact Analysis for Proposed Alternative #2 for Proposed State-only Revisions to the Air Quality Control Commission's Reg. Number 7 (Dec. 11, 2008), attached hereto as Exhibit 162.
[505] TSD, 6-8, 9.

them dominant emissions sources,[507] emitting on the order of 105 Bcf of methane across the production, processing, and transmission and storage sectors.[508] Compressor VOC emissions are, unsurprisingly, also substantial. EPA states that just the *newly installed* compressors (not including compressors installed to replace existing compressors) now covered by the proposed standards would emit 2,798 tons of VOCs annually in the absence of the proposed standard.[509] Emissions from existing reciprocating compressors in the processing and transmission sectors alone equal approximately 37,000 Tpy.[510] EPA has low-cost options to extend controls to these existing sources. Emission guidelines that require replacement of rod-packing from existing compressors in the processing sector would remove approximately 25,258 tons of VOCs and 90,694 tons of methane. Similar reductions can be achieved from compressors in the transmission and storage sector, namely 5,010 tons of VOCs and 181289 tons of methane. These reductions, which total 30,268 tons of VOC and 271,983 tons of methane, do not include reductions from the 34,930 compressors located at wellheads, gathering and boosting stations. Emissions reductions from these sources are not estimated since EPA's GHG Inventory does not disaggregate wellhead compressors from those located at gathering and boosting stations yet EPA applies different emission reductions to each type of compressor.[511]

Beginning with reciprocating compressors, which are by far the more common compressor type, EPA can directly extend its new source performance standard. That standard would require operators to replace reciprocating compressor rod-packing "before the compressor has operated for 26,000 hours."[512] This simple maintenance standard, applied at new sources, saves 1,759 tons per year of VOCs,[513] and does so at a low cost. EPA estimates cost per ton of VOC controlled (with saved natural gas offsets) at a few thousand dollars or less (including savings in some cases) for gathering, processing, transmission, and storage compressors.[514] Nothing prevents operators from immediately applying an identical maintenance approach to existing compressors, and EPA must so require.

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[506] EPA, *U.S. National Inventory of Sources and Sinks 1990-2009* (2011) at Table A-120., p. A-122. EPA does not provide an estimate of the number of existing centrifugal compressors in the TSD.

[507] This emissions source is both under-controlled and under-measured: In 2010, for instance, EPA uprevised its emissions factor for leaks from centrifugal compressor from 0 to 233 metric tons CH_4/year. TSD at 9.

[508] *See* EPA, *U.S. National Inventory of Sources and Sinks 1990-2009* (2011) at Table A-120., p. A-122.

[509] TSD, Table 6-5.

[510] These calculations are based on EPA's baseline VOC emissions for reciprocating compressors in Table 6-3 of the TSD. Note because EPA does not provide estimates of the number of reciprocating compressors at wellheads or in the storage sector, and this information is also not provided in EPA's GHG inventory, we do not here estimate emissions from compressors in these sectors.

[511] See TSD 6-6, noting that the GHG Inventory does not separate wellhead from gathering and boosting compressors and Table 6-6 applying emission reductions to different types of compressors.

[512] Proposed 40 C.F.R. §60.5385.

[513] TSD, Table 6-6.

[514] TSD, Table 6-7.

Centrifugal compressors also offer significant control opportunities. Requiring dry seals for non-wellhead compressors alone, as EPA now proposes for new sources, would reduce VOC emissions by 329 tons per year (this number is low because EPA assumes few new installations of centrifugal compressors each year, and replacements of existing compressors are not included in this figure).[515] Using the estimate of existing centrifugal compressors in the 2009 GHG Inventory, replacement of wet seals with dry on compressors would remove 13, 926 tons per year of VOCs (11,628 from the processing sector and 2298 from the transmission/storage sectors).[516] The resulting savings are substantial: For each ton of VOC avoided, operators recover over $25,405 in avoided natural gas loss and O&M costs annually at transmission and storage compressors, and another $6,892 at processing compressors.[517] The result is millions of dollars in avoided costs each year.[518]

If EPA's emissions standards drove operators to replace wet seals with dry seals at existing compressors, operators would capture far more benefits, as existing centrifugal compressors greatly outnumber new compressors. We therefore recommend that EPA set these standards to drive such replacements in existing compressors.

3. Standards for Existing Storage Vessels

Under the proposed NESHAP, EPA has already proposed a 95% emissions control requirement for new and existing storage vessels at major sources of HAPs.[519] For new storage vessels not covered by the NESHAP, EPA has proposed an NSPS requirement that would apply an identical standard at wellsite storage vessels which have the potential to emit 6 or more tons per year of VOCs, at a cost of $143 per ton of VOCs captured for large vessels.[520,521,522] Combined, these standards cover many tanks, but likely leave a population of existing vessels which are not major HAP sources.

These remaining existing tanks must be subject to the same degree of emissions control as is required for all other tanks. EPA estimates the existing population of condensate tanks in 2008 to be 57, 8447.[523] Such a standard would be cost-effective, especially if phased in over a reasonable time period. Colorado, for instance, developed cost data for retrofits of condensate tanks, concluding that condensate tanks could be retrofitted for

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[515] TSD, Table 6-8.
[516] EPA, *U.S. National Inventory of Sources and Sinks 1990-2009* (2011), Table A-120., p. A-122.
[517] TSD, Table 6-22.
[518] RIA, Table 3-3.
[519] 76 Fed. Reg. at 52,813. (Proposed 40 C.F.R. §63.766).
[520] *Id.*
[521] 76 Fed. Reg. at 52,800. (Proposed 40 C.F.R. § 60.5395).
[522] EPA has proposed to exempt some small throughput vessels from this standard.
[523] TSD 7-4. Note the most recent GHG Inventory does not provide an estimate of the population of tanks used in the natural gas sector so this analysis relied on the information contained in the TSD rather than EPA's most recent GHG Inventory.

roughly $6,921 per tank.[524] Using the average VOC emissions for condensate and oil tanks presented in Table 7-12 of the TSD (103 Tpy) in 2008 the existing tanks population was responsible for the emission of 59,580,041 Tpy of VOCs into the atmosphere. If the NSPS 95% control requirement were extended to these sources, it would result in the removal of 56,601, 039 Tpy VOCs, and would also achieve substantial methane reductions.

In view of the potential for cost-effective emissions savings, Colorado requires existing tanks emitting more than one ton per year of VOCs within certain ozone nonattainment area to retrofit to meet a 95% emissions control requirement[525] within the first 90 days of producing a newly drilled, re-completed, re-fractured or otherwise stimulated well.[526] After that, controls may be removed provided the owner or operator can demonstrate that all of the tanks within his or her control meet system-wide emission limits.[527] EPA must apply the same approach nationally. Whatever control efficiency requirement it ultimately applies to new tanks must be extended to existing vessels which are not already covered by the NESHAP, and must be applied on a reasonably strict retrofit schedule.

4. Standards for Existing Wells

Well completions of hydraulically fractured wells[528] and liquids unloading from conventional wells[529] are two of the largest sources of methane and VOCs from the oil and natural gas industries. EPA proposes to define well completions and recompletions as modifications, which would trigger the performance standards. Proposed 40 C.F.R. § 60.5365. Unfortunately, EPA fails to regulate liquids unloading altogether. Above, we call for this failing to be rectified. As we note above, liquids unloading is a physical alteration of the well which increases emissions and thus should be considered a modification which would trigger performance standards.

If the proposed rule stands, and EPA also regulates liquids unloading and considers it to be a modification, EPA will be able to control the major sources of methane emissions from existing conventional and hydraulically fractured gas wells (even without a 111(d) standard). If, however, EPA alters the proposal concerning hydraulically fractured wells

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[524] Colorado Air Quality Control Commission, *Revised Final Economic Impact Analysis for Proposed Alternative #2 for Proposed State-Only Revisions to the Air Quality Control Commission's Reg. Number 7* (Dec. 11, 2008), attached hereto as Exhibit 162.

[525] CO. Department of Public Health and Environment Regulation 7 at XII.D & XVII.C; *see also* Colorado Oil and Gas Conservation Commission Rule 805(b)(2)(A) & (B) (requiring such retrofits in certain counties, and within ¼ mile of schools, hospitals, and similar facilities).

[526] CO. Department of Public Health and Environment Regulation 7 at XII.D; *see also* Colorado Oil and Gas Conservation Commission Rule 805(b)(2)(A) & (B) (requiring such retrofits in certain counties, and within ¼ mile of schools, hospitals, and similar facilities, for tanks that emit 5 Tpy of VOCs or more).

[527] CO. Department of Public Health and Environment Regulation 7 at XII.D.

[528] 76 Fed. Reg. at 52,756.

[529] US Greenhouse Gas Inventory, Table A-120 at A-149 – A-153.

or fails to consider liquids unloading as a modification in the final rule, it should issue 111(d) standards to fill any gaps.

Of course, the existing well standards should also reflect the greater coverage we recommend for new sources, *supra*. Most significantly, 111(d) standards should regulate oil wells, in addition to gas wells.

5. Standards for Leak Detection and Repair

EPA proposes to require all new gas processing plants to comply with the enhanced leak detection standards of subpart VVa, while existing plants will continue to be bound by the more relaxed standards of subpart VV.[530] This is not an effective approach. As EPA explains, subpart VVa not only captures more VOCs (and methane), it is also less expensive per ton of pollutant because "[a]lthough the cost of repairing more leaks is higher, the increased VOC control afforded by subpart VVa level controls more than offsets the increased costs" thanks to captured natural gas sales.[531]

EPA estimates there are 577 existing plants operating in the U.S. today.[532] Applying the annual emission reductions from implementing a Subpart VVa LDAR program to individual gas plants estimated in Table 8-13 of the TSD, extending the Subpart VVa requirements to existing sources would result in an additional reduction of 7,790 tons of VOCs from the atmosphere.

EPA must apply this more effective, and less expensive, standard to existing processing plants immediately. No technical or logistical efforts appear to require a long phase-in period, though some need to hire or train sufficient workers may delay phase-in somewhat. Even assuming some phase-in period, though operators and the public can benefit from enhanced leak control as soon as EPA extends these standards to existing sources.

6. State Models

As we have described above, standards in Colorado and Wyoming demonstrate that standards of performance to control air pollution from existing sources are both "achievable" and "adequately demonstrated".[533] To underline this point, we gather those requirements here. Table 3 table illustrates the scope of existing sources covered by Wyoming and Colorado's rules.

Table 3

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[530] *See* 76 Fed. Reg. at 52,764.
[531] *Id.* at 52,765.
[532] TSD, 8-16.
[533] See 42 U.S.C. § 7411(1)(1) (defining "standard of performance"); 42 U.S.C. § 7411(d)(1).

Existing Source	Proposed NSPS	Wyoming	Colorado
Condensate tanks	95% control of tanks with emissions ≥ 6 Tpy VOCs.	CDAs and JPAD[534]: New and modified facilities must control VOC flash emissions by 98% upon first date of production (FDOP). May remove controls after one year if VOC emissions < 8 tpy. Statewide: New and modified facilities must control VOC flash emissions ≥10 tpy by 98% upon FDOP. May remove controls after one year if emissions < 8 tpy.	Tanks with VOC emissions greater than 2 Tpy, under common ownership and control, and with cumulative emissions = or > 30 Tpy VOCs located in ozone NA or Attainment/Maintenance area, must meet system-wide declining caps that require 90% control during ozone season and 70% control remainder of year.[535] Individual tanks located at gas processing plants in ozone NA or Attainment/Maintenance area, with emissions > 2 Tpy VOCs must achieve 95% control on rolling 12-month basis.[536] Tanks with PTE 5 Tpy or more located near public places in the Piceance basin must achieve 95% VOC control.[537]
Crude oil tanks	95% control of tanks with VOC emissions ≥ 6 Tpy.	Same as condensate tanks.	Tanks with PTE 5 Tpy or more located near public places in the Piceance basin must achieve 95% VOC control.[538]
Produced water tanks	N/A	Same as condensate	Tanks with PTE 5 Tpy or more located near public places in the

[534] *Id*. CDA refers to "Concentrated Areas of Development". JPAD refers to the Jonah and Pinedale Anticline Development Area.
[535] Colorado Reg. 7, XII.D.2.(a)(x).
[536] Reg. 7, XII.G.2.
[537] Colorado Oil and Gas Conservatin Commission Rule ("COGCC") 805(b)(2)(A),(B).
[538] Colorado Oil and Gas Conservatin Commission Rule 805(b)(2)(A),(B).

		tanks.	Piceance basin must achieve 95% VOC control.[539]
Pneumatic devices	Low bleed devices in production and transmission sectors. No-bleed devices at gas plants.	Operators must use low or no-bleed devices or route discharge streams to closed loop systems.	New and existing gas-activated controllers at or upstream of gas processing plants in ozone nonattainment (NA) and Attainment/Maintenance areas (NA/M) must be low-bleed.[540] Statewide, new, replaced or repaired devices in production sector must be low or no-bleed, where technically feasible.[541]
Gas processing plants	N/A	N/A	Plants in ozone nonattainment areas or Attainment/Maintenance areas must comply with the same federal leak detection and repair standards that apply to new sources in subpart KKK.[542]
Wells	Reduced emission completions for re-completed and re-fractured hydraulically fractured gas wells.	Green completions.	Green completions.

Wyoming and Colorado's standards to control air pollution from existing storage vessels, pneumatic devices, and wells are based upon or reflect the same practices or standards that EPA has determined in this rule represent Best Demonstrated Technology, or Best System of Emission Reduction, for new sources. This fact demonstrates that these practices and standards are achievable and adequately demonstrated for existing sources as well. EPA thus must look to the Wyoming and Colorado standards when designing emission guidelines for existing sources as required by the Act.

7. Conclusion

[539] Colorado Oil and Gas Conservatin Commission Rule 805(b)(2)(A),(B).
[540] Reg. 7, XVII.
[541] COGCC Rule 805(b)(2)(E).
[542] Reg. 7, XII.G.3.

Section 111(d) and its implementing regulations require EPA to control VOCs and methane at existing sources as well as at new sources. As we have demonstrated, these existing source standards can readily be extrapolated from EPA's work on the new source performance standards, can be applied quickly, and are likely to be highly cost-effective, especially if phased in properly. As with the earlier landfill standards, oil and gas 111(d) standards will have significant public health and welfare benefits, reducing ozone formation, HAPs, and the sector's contribution to climate change. EPA must therefore include a proposal for such standards in or concurrent with its final rulemaking for the 111(b) standards, or include a schedule in the 111(b) rulemaking committing to a proposal in the near future.

VI. COMPLIANCE AND ENFORCEMENT ISSUES

EPA's proposed standards cover thousands of facilities spread across a wide range of terrains and jurisdictions. To properly enforce them, EPA and the states will need substantial resources and clear authority. In our sector-specific comments, we have made several suggestions for clarifying the rule to enhance its enforceability. In this section of the comments we consider enforcement issues more generally, focusing on the implications of EPA's proposal to exempt certain sources from permit requirements under Title V of the Clean Air Act and upon EPA's proposal to develop an affirmative defense for noncompliance. We trust these suggestions will help make the final rule enforceable as a practical matter, and thus ensure its full rigor, as well as overall transparency and widespread compliance.[543]

A. Title V Exemption

[543] With regard to transparency, it is important to note – and EPA must clarify -- that all information reported pursuant to proposed 40 C.F.R. §§ 60.5410, 60.5415, and 60.5420 must be disclosed to the public. Section 114 of the Clean Air Act authorizes EPA to collect information and mandates that this information be available to the public. EPA regulations provide that all data collected by EPA under any CAA provision will be presumed to have been collected under § 114, regardless of whether the authority providing for the collection cites § 114, and that this information will "shall" be public. 40 C.F.R. §§ 2.301(b)(2), (f). The only exception is that EPA may determine that certain information other than "emission data" is confidential business information that need not be disclosed. 42 U.S.C. § 7414(c). The exemption does not apply here, because all of the information reported pursuant to the proposed NSPS rules is "emission data." "Emission data means . . . [i]nformation necessary to determine the identity, amount, frequency, concentration, or other characteristics" of emissions actually emitted by a source or that the source was authorized to emit. 40 C.F.R. § 2.301(a)(2)(i)(A)-(B). This information includes "a description of the manner or rate of operation of the source" and a "general description of the location and/or nature of the source." *Id.* § 2.301(a)(2)(i)(B)-(C). The information required pursuant to the proposed NSPS falls solidly within this category. Although EPA has set technology or work practice standards for many sources, these standards serve as a surrogate for actual emissions. Even if this information was not emission data, nothing indicates that it would be confidential business information that EPA could shield from disclosure.

EPA proposes to exempt well completions, pneumatic devices, compressors and small storage tanks from the obligation to obtain Title V permits.[544] As a matter of law, promulgation of an NSPS regulating these entities would bring them within the ambit of Title V.[545] When promulgating an NSPS, however, EPA may exempt non-major sources from Title V obligations in the limited circumstances where compliance would be "impracticable, infeasible, or unnecessarily burdensome" for the source.[546] Here, EPA argues that Title V is an "unnecessary[] burden[]."[547] We strongly object to the proposed Title V exemption.

"Title V of the 1990 Amendments to the Clean Air Act (CAA) requires that certain air pollution sources, including every major stationary source of air pollution, each obtain a single, comprehensive operating permit to assure compliance with all emission limitations and other substantive CAA requirements that apply to the source."[548] Regulations implementing Title V are codified at 40 C.F.R. parts 70 and 71. A Title V permit must, *inter alia*, list all emissions limitations and standards applicable to the source;[549] ensure that monitoring and recordkeeping are sufficient to demonstrate compliance;[550] and require payment of fees.[551]

Rather than treating the statutory exemption as a narrow limitation on a rule of general applicability adopted by Congress, EPA seems to assume that the exemption is available as a matter of right, unless some added benefit can be demonstrated. Accordingly, instead of simply examining whether Title V permitting is "unnecessarily burdensome," EPA interprets the exemption as permitting it to balance the enforcement and environmental benefits of Title V against the costs to the facility operator.[552] Moreover, the proposed rule understates the benefits of Title V by completely ignoring the role Title V fees play in funding state enforcement programs. The proposal conversely assumes that costs to operators are unbearable without considering the ways in which these costs may (and are likely to) be reduced or providing any specific data regarding the magnitude of these costs and the operators' ability to bear them. Accordingly, the proposed title V exemption is insufficiently supported and, in any event, unwarranted.

1. EPA's Multifactor "Unnecessarily Burdensome" Test

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[544] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. § 60.5370(c)).
[545] 42 U.S.C. § 7661a(a), 40 C.F.R. § 70.3(a)(2).
[546] 42 U.S.C. 7661a(a), 40 C.F.R. § 70.3(b)(2).
[547] 76 Fed. Reg. at 52,751.
[548] *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 993-94 (D.C. Cir. 2005) (citing 42 U.S.C. §§ 7661a(a), 7661c(a)), attached hereto as Exhibit 163
[549] 40 C.F.R. § 70.6(a)(1)
[550] 40 C.F.R. § 70.6(a)(3);
[551] 40 C.F.R. §§ 70.6(7), 70.9.
[552] *Id.*

Following a trend established in several recent rulemakings, EPA's proposal discusses five factors in evaluating whether Title V imposes an unnecessary burden.[553,554] Specifically, EPA articulates a four-factor test, but then adds an additional consideration. The four factors are:

(1) Whether Title V would result in significant improvements to the [applicable substantive] compliance requirements . . .

(2) Whether Title V permitting would impose a significant burden on these non-major sources and whether that burden may be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies;

(3) Whether the costs of Title V permitting for these non-major sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources;

(4) Whether there are implementation and enforcement programs in place that are sufficient to assure compliance . . . without relying on Title V permits.[555]

After discussing these factors, EPA separately considers "whether exempting . . . [these] sources would adversely affect public health, welfare or the environment."[556]

As a threshold matter, we note the cumbersome nature of this test. The distinction, if any, between the first and fourth factors is unclear. Similarly, evaluation of effects on "public health, welfare or the environment" largely subsumes the question of whether Title V would improve compliance with substantive standards, because EPA must presume that those standards further these broader goals. Lastly, insofar as the fourth and fifth factors have independent relevance, EPA must discuss these factors before the third "factor," which itself appears to be merely a weighing of factor two against the other concerns. Moreover, EPA's application of its factors in this instance would seem to allow it to exempt all sources. EPA has not explained how the costs and benefits of Title V permitting in this instance are significantly different from the burden imposed on other sources that are subject to Title V obligations. Moreover, EPA's application of its factors in this instance would seem to allow it to exempt all sources. EPA has not

[553] 76 Fed. Reg. at 52,751 (citing *Exemption of Certain Area Sources From Title V Operating Permit Programs*, 70 Fed. Reg. 75,320, 75323 (Dec. 19, 2005)).
[554] EPA cites this document as the "Title V Exemption Rule." *See* 76 Fed. Reg. at 52751. Rather than announce a general rule regarding Title V exemptions, the cited rule was a case-specific determination as to whether five nonmajor source categories subject to NESHAP should be exempted from Title V. 70 Fed. Reg. at 75,320, 76,323, attached hereto as Exhibit 164. In the proposal and final rule for the five-category exemption, EPA used a test similar to the one EPA uses here. *Id.*, *see also Proposal To Exempt Area Sources Subject to NESHAP From Federal and State Operating Permit Programs*, 70 Fed. Reg. 15,250, 15,253 (March 25, 2005), attached hereto as Exhibit 174.
[555] *Id.*
[556] *Id.*

explained how the costs and benefits of Title V permitting in this instance are significantly different from the burden imposed on other sources that are subject to Title V obligations.

2. Title V Permit Fees Will Further Environmental Protection and Compliance with the NSPS

Assuming *arguendo* that EPA's test lays out a reasonable set of distinguishable factors, in discussing the three "benefit" factors of the above balancing test here, EPA failed to consider the important role Title V fees play in the CAA's regulatory regime.

In evaluating the first factor, EPA explained that "[o]ne way that Title V may improve compliance is by requiring monitoring (including recordkeeping designed to serve as monitoring) to assure compliance with permit terms and conditions reflecting the emission limitations and control technology requirements imposed in the standard."[557] EPA concluded the proposed NSPS's reporting, monitoring and recordkeeping requirements were, *e.g.*, "sufficient to assure compliance with the proposed [NSPS] requirements," such that the monitoring, reporting and recordkeeping required by Title V would provide little additional benefit.[558] We note that Title V requires "prompt reporting of deviations from permit requirements" and reporting on a semiannual, rather than annual, basis,[559] whereas the proposed NSPS only requires reporting on an annual basis, together with notification of well completions.[560] Timelier reporting would facilitate enforcement.

More importantly, reporting is not the only mechanism by which Title V improves compliance. Title V also improves compliance by requiring operators to pay fees that, in turn, fund state enforcement programs. Title V requires that permit programs impose and collect annual fees "sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program requirements of [Title V], including the reasonable costs of . . . implementing and enforcing the terms and conditions of any . . . permit (not including any court costs or other costs associated with any enforcement action)."[561] As EPA has interpreted this language, Title V permit fees may be used for all enforcement costs for Title V sources incurred prior to the filing of an administrative or judicial compliant.[562]

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[557] 76 Fed. Reg. at 52,752.
[558] *Id.*
[559] 40 C.F.R. § 70.6(a)(3)(iii)(B)
[560] 76 Fed. Reg. at 52,805-08 (Proposed 40 C.F.R. §§ 60.5410, 60.5415, 60.5420).
[561] 42 U.S.C. § 7661(b)(3)(A)(ii).
[562] *Reissuance of Guidance on Agency Review of State Fee Schedules for Operating Permits Programs Under Title V*, at pages 3 and 16 of 25 (Aug. 4, 1993), available at http://www.epa.gov/ttn/oarpg/t5/memoranda/fees893.pdf, attached hereto as Exhibit 166.

These fees are essential, because state budgets have slashed delegated CAA programs to the point where almost all available resources are derived either from CAA grants or Title V fees. For example, Oregon's Department of Environmental Quality states that

> Because other funding sources have become less available over time, fees pay for 90 to 95 percent of the Air Contaminant Discharge Permit Program. To address budget shortfalls, the Oregon Legislature has cut general fund support for the Air Contaminant Discharge Permit Program and shifted more of the funding to fees. Federal funds for state air quality programs have been flat for many years, and prospects for significant increases in federal funds are slim given federal budget challenges.[563]

Because Title V permit fees cannot be used for purposes other than enforcement and implementation of the Title V program, Title V fees directly and necessarily increase enforcement capacity.

EPA itself implicitly concedes that states lack the resources to enforce the proposed NSPS obligations. In discussing the status of implementation and enforcement programs (the fourth "unnecessarily burdensome" factor), EPA states that

> Before EPA will delegate [the NSPS] program [to a state], EPA will evaluate the state programs to ensure that states have adequate capability to enforce the CAA section 111 regulations and provide assurances that they will enforce the NSPS. In addition, EPA retains authority to enforce this NSPS anytime under CAA sections 111, 113 and 114. Accordingly, we can enforce the monitoring, recordkeeping and reporting requirements, which, as discussed under the first factor, are adequate to ensure compliance with this NSPS.[564]

Although EPA retains legal authority to enforce the NSPS where states fail to do so (*e.g.*, because of a lack of funding), EPA has not examined whether EPA itself has the resources to enforce these requirements nationwide without the benefit of Title V permit fees.

It is difficult to imagine how EPA can conclude that publicly taking the cop off the beat by eliminating the principal source of funding for many state enforcement programs will have no effect on compliance rates. Such an assumption is plainly arbitrary and capricious, and unsupported by the record.

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[563] http://www.deq.state.or.us/aq/permit/index.htm (last visited Oct. 24, 2011), attached hereto as Exhibit 167.
[564] 76 Fed. Reg. at 52,753.

Title V permitting also serves to improve compliance by increasing transparency and providing a vehicle where questions of the applicability of the NSPS (and the several exemptions thereto) are identified and resolved. Under EPA's proposal sources would decide these issues with no opportunity for upfront state or federal review or public disclosure of a decision by the source that it believed the standard did not apply.

Third party verification does not obviate the need for Title V fees. The preamble to the proposed rule states that EPA "want[s] to state clearly here that third party verification would not supersede or substitute for inspections or audit of data and information by state, local and tribal agencies and EPA."[565] Even if third party verifiers were capable of substituting for government enforcement, EPA has provided no evidence that the cost to industry of third party verifiers sufficient to play this role would be less than the cost of an efficiently structured Title V program.

Thus, Title V protects the environment and ensures compliance with NSPS requirements both by mandating reporting and by funding enforcement programs. Title V also increases compliance is by facilitating judicial enforcement. A Title V program must "provide for judicial review of permitting actions."[566] Another benefit of Title V EPA does not discuss is the fact that Title V permittees are required to submit annual compliance plans and compliance certifications. 42 USC 7661b(b)(1),(2); 40 CFR 71.5(d). Failure to do so, and knowing false material statements in the certifications is subject to criminal penalties. 42 USC 7413(c)(1),(2).

3. EPA overstates the burden of the Title V program

While EPA has understated the benefits of the Title V program, EPA has overstated the burden the program imposes on facility operators. EPA has provided scant and flawed information regarding costs of compliance, ignored ways in which the Title V program may and would likely be streamlined, and provided no information regarding facilities' ability to bear these costs.

EPA begins with an overstated estimate of the costs of compliance. "EPA estimated that the average cost of obtaining and complying with a Title V permit was $65,700 per source for a 5-year permit period, including fees."[567] EPA bases this figure on an "Information Collection Request (ICR) for Part 70 Operating Permit Regulations, January 2007, EPA ICR Number 1587.07."[568] We have been unable to locate this supporting information in the docket or on EPA's website; only the information request, rather than the conclusions drawn from the responses thereto, appears to be available in the

[565] 76 Fed. Reg. at 52,750.
[566] *Arizona Pub. Serv. Co. v. EPA*, 211 F.3d 1280, 1284 (D.C. Cir. 2000) (citing 42 U.S.C. § 7661a(b)(6), (7)), attached hereto as Exhibit 168.
[567] 76 Fed. Reg. at 52,753.
[568] *Id.*

Federal Register.[569] The $65,700 figure apparently represents the average across all facilities subject to Title V, including major sources under the PSD and NESHAP programs, and therefore does not represent the average cost of compliance for non-major sources subject solely to NSPS, such as the facilities being regulated here.[570]

Rather, based upon EPA's "presumptive minimum Title V fee" of $46.00 per ton of Title V pollutant actually emitted,[571] and EPA's statement that VOC emissions from a wellhead controlled with a green completion would be about 2.3 tons,[572] the federal minimum permit fee would be 2.3 times $46, or $105.80 per hydraulic fracturing operation. This cost is not even remotely unreasonable. It is trivial when compared to the value of the product generated, even for "small" operators.

Further, EPA failed to consider other tools to lessen the (already low) cost of Title V compliance. For example, permitting authorities may issue "general permits" encompassing a class of similar sources.[573] Numerous states have adopted general Title V permits for dozens of sectors.[574]

General permits can significantly ease the costs of compliance. In one context, EPA has stated that a normal Title V permit requires 200 hours of "permit renewal" work per year, whereas re-application for a general permit requires only two hours per year.[575] In this circumstance, where EPA has determined that the majority of the Title V monitoring, recording and recordkeeping overlaps with that required by the proposed NSPS, the permit application and renewal hours presumably constitute a large fraction of the burden imposed by Title V. Thus, reducing those hours by a factor of 100 would significantly reduce the costs of Title V compliance. In other cases where EPA has exempted sources from Title V, EPA has done so only after explicitly stating that Title V would remain unnecessarily burdensome even if general permits were used to reduce costs.[576,577] Although we contend that these rulemakings' often-cursory dismissal of

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[569] *See Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; State Operating Permit Regulations (Renewal); EPA ICR No. 1587.07, OMB Control No. 2060–0243*, 72 Fed. Reg. 32,289 (June 12, 2007), attached hereto as Exhibit 169.

[570] *See Exemption of Certain Area Sources From Title V Operating Permit Programs*, 70 Fed. Reg. 75,320, 75,325 (Dec. 19, 2005) (discussing limits of the preceding 2004 Information Collection Request).

[571] *See* http://www.epa.gov/airquality/permits/historicalrates.html, attached hereto as Exhibit 170.

[572] RIA at 3-6.

[573] 40 C.F.R. § 70.6(d).

[574] *See Tool Selection Guide: A Review of Permitting Options for Implementing Area Source Rules*, Report to EPA prepared by Industrial Economics, Inc. pp. 17-26 (Nov. 11, 2009) (available at http://www.epa.gov/erp/files/selectionguide.pdf) (cataloguing and summarizing general permit programs in six states), attached hereto as Exhibit 171.

[575] *Exemption of Certain Area Sources From Title V Operating Permit Programs*, 70 Fed. Reg. 75,320, 75,341 (Dec. 19, 2005).

[576] *See, e.g.*, *National Emission Standards for Hazardous Air Pollutants for Area Sources: Chemical Preparations Industry*, 74 Fed. Reg. 39,013, 39,021 (Aug. 5, 2009), attached hereto as Exhibit 172, *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Paints and Allied Products Manufacturing*, 74 Fed. Reg. 26,142, 26,152 (June 1, 2009), attached hereto as Exhibit 173.

general permits was inadequate, EPA did not even mention the possibility of using general permits here.

EPA also underestimates industry's ability to bear the costs of Title V compliance. EPA states that "some of the non-major sources that would be subject to the proposed NSPS *may* be small entities that *may* lack the technical resources [sic] and, therefore, need assistance from the permitting authorities to comply with the Title V permitting requirements."[578] EPA purports to support this conjecture by noting the sheer number of annually affected *facilities* (20,000 well completions, 14,000 new controller installations, 500 compressors and 300 storage vessels), but EPA provides no data regarding the number of *businesses* operating these facilities. Thus, EPA's mere speculation that "some" operators "may" be small and "may" lack technical expertise provides no justification for concluding that regulated entities will be unable to bear the costs of Title V compliance. Larger entities have greater financial resources and, perhaps more importantly, economies of scale relating to Title V technical expertise which will drive down the cost of compliance per facility. Here, it is important to recognize that the "technical expertise" that will be required is that needed to comply with the underlying NSPS, not the Title V permit. Small operators with limited technical expertise respecting the performance of low-bleed controllers or dual double dry seals for compressors may need to obtain assistance. However, the Title V permit adds no substantive compliance obligation, it merely makes sure that all Federal obligations applicable to a source can be found in one document. Moreover, in addition to specifically authorizing general permits, the Act also specifically authorizes the issuance of one permit for a facility with multiple sources.[579] Thus, the operator of a well field with 100 wells would only need to get a single general permit in order to comply with Title V permitting requirement.

Whereas EPA provides no information about the number of small entities regulated here, in other recent rulemakings EPA has only held that Title V exemptions were

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[577] See also *Revision of Source Category List for Standards Under Section 112(k) of the Clean Air Act; National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Aluminum, Copper, and Other Nonferrous Foundries*, 74 Fed. Reg. 6,510-01, 6,521 (Feb. 9, 2009), attached hereto as Exhibit 174; *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Nine Metal Fabrication and Finishing Source Categories*, 73 Fed. Reg. 18,334-01, 18,359 (Apr. 3, 2008), attached hereto as Exhibit 175; *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Plating and Polishing Operations*, 73 Fed. Reg. 14,126-01, 14,141 (March 14, 2008), attached hereto as Exhibit 176; *National Emission Standards for Hazardous Air Pollutants for Area Sources: Clay Ceramics Manufacturing, Glass Manufacturing, and Secondary Nonferrous Metals Processing*, 72 Fed. Reg. 53,838-01, 53,850 (Sept. 20, 2007), attached hereto as Exhibit 177; *National Emission Standards for Hazardous Air Pollutants for Area Sources: Acrylic and Modacrylic Fibers Production, Carbon Black Production, Chemical Manufacturing: Chromium Compounds, Flexible Polyurethane Foam Production and Fabrication, Lead Acid Battery Manufacturing, and Wood Preserving*, 72 Fed. Reg. 38,864-01, 38,875 (July 26, 2007), attached hereto as Exhibit 178.

[578] 76 Fed. Reg. at 52,753. EPA fails to mention that Title V permitting assistance is currently provided as a routine matter by permitting authorities.

[579] See 42 U.S.C. 7661a(c).

warranted when EPA had specific information regarding the proportion of small businesses affected.[580] Here, EPA has provided no information indicating that any appreciable fraction of sources are owned by "small" business entities that lack technical acumen or that have particularly limited ability to bear the costs of Title V compliance.[581]

Here, it is important to recognize that the "technical expertise" that will be required is that needed to comply with the underlying NSPS, not the Title V permit. Small operators with limited technical expertise respecting the performance of low-bleed controllers or dual double dry seals for compressors may need to obtain assistance. However, the Title V permit adds no substantive compliance obligation, it merely makes sure that all Federal obligations applicable to a source can be found in one document.[582]

In summary, EPA has ignored the role Title V fees play in ensuring NSPS compliance; failed to demonstrate that, absent fees, states or EPA have capacity to enforce the NSPS; and failed to show that Title V imposes burdens that are disproportionate to its benefits or that regulated facilities are unable to bear. Accordingly, EPA must withdraw its proposal to exempt well completions, compressors, pneumatic devices and small storage tanks from the requirement to seek and hold Title V operating permits.

4. EPA's Third Party Verification Plans are Ill-Defined

EPA briefly proposes a "third party verification" program as a "complement" to the annual compliance certification. [583]EPA has not, however, provided a coherent explanation as to the role these verifiers would play. Without a clear picture as to the role of these private actors, it is impossible to comment on the appropriateness of their use. We accordingly object to adoption of a third-party verification system for the

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[580] *Standards for Paints and Allied Products Manufacturing*, 74 Fed. Reg. at 26,152 ("almost all of the approximately 2,190 paints and allied products manufacturing facilities that would be affected by this proposed rule are small entities; over half have nine or fewer employees."), attached hereto as Exhibit 179; *Standards for Aluminum, Copper, and Other Nonferrous Foundries*, 74 Fed. Reg. at 6521 ("approximately 98 percent of the plants that would be affected by the proposed rule are small businesses, most with fewer than 50 employees and about 25 percent or more with only one to four employees."), *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Plating and Polishing Operations*, 73 Fed. Reg. 14,126-01, 14,141 (March 14, 2008) ("nearly all of the approximately 2,900 plating and polishing facilities affected by this proposed rule are small businesses, some with as few as one or two employees.").

[581] Although EPA's prior rulemakings have looked to the raw number of businesses and looked to the fraction of this number constituted by "small" business, a better approach would be to look to the fraction of *facilities* owned by small business.

[582] EPA also fails to mention that Title V permitting assistance is currently provided as a routine matter by permitting authorities.

[583] 76 Fed. Reg. at 52,750.

proposed O&G NSPS at this time. We nonetheless alternatively offer the following comments on third party verification generally.

A threshold question, which EPA has not answered, but must address, is why it proposes to use third party verification at all in this context. EPA "state[s] clearly [in its proposal] that third party verification would not supersede or substitute for inspections or audit of data and information by state, local and tribal agencies and EPA."[584] EPA has not identified any function that third party verifiers can perform more effectively, or more cheaply, than can permitting authorities. Thus, there is no apparent reason to require industry to fund third party verifiers through some yet un-described system instead of requiring industry to fund verification by the permitting agencies through title V. We are particularly troubled by the possibility that EPA sees its vague proposal for third-party verifiers as justification for exempting wellheads, compressors, pneumatic devices and small storage tanks from title V. To be clear, the proposal itself explicitly disclaims such reliance. EPA has stated that third party verification would not displace government inspection and regulation, and EPA's discussion of the proposed title V exemption does not refer to third party verifiers. Nonetheless, we wish to highlight the fact that EPA cannot and should not substitute an undefined private framework for an established regulatory regime with well-defined provisions for public disclosure and judicial enforcement.

A second issue, which EPA recognizes, is that "third party verification paid for by industry" presents a potential conflict of interest that can compromise the verification's validity. In the late 1990s, EPA's National Enforcement Investigations Center audits of private LDAR monitoring "show[ed] that the number of leaking valves and components is up to 10 times greater than had been reported by certain re-fineries"; these reports included reports generated by third parties.[585] In light of this history, any proposal for third party verification must, at minimum, address conflicts of interest by incorporating an accreditation scheme and by requiring verifiers to be paid through an industry consortium rather than by individual facilities. For a model accreditation scheme, EPA could look to the California Air Resources Board's accreditation of third party verifiers adopted pursuant to California's greenhouse gas reporting rule.[586] EPA could similarly accredit and oversee third party verifiers, requiring that only accredited verifiers be used. EPA could also require that third party verifiers be paid by an industry consortium, rather than by individual facilities, attenuating the financial connection and accompanying conflict. EPA must further explore schemes under which the permitting authority, rather than the facility operator, selects the verifier to be used in particular

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[584] *Id.*

[585] EPA Office of Regulatory Enforcement, *Proper Monitoring Essential to Reducing 'Fugitive Emissions' Under Leak Detection and Repair Programs* (Oct. 1999)*, available at* http://www.epa.gov/compliance/resources/newsletters/civil/enfalert/emissions.pdf, attached hereto as Exhibit 180.

[586] *See* www.arb.ca.gov/cc/reporting/ghg-ver/ghg-ver.htm.

cases. If it moves forward, it must use such a model, or explain why it has failed to do so.

If third party verifiers are used, any information they collect should be as fully available to the public, comparable to information collected by EPA. EPA asks whether third party verifiers could serve as a "clearinghouse for notifications, records and compliance certifications."[587] Any such clearinghouse should be fully available online and provide the general public with full access to the collected data, on a searchable and tabular basis.

Finally, we address the roles EPA has proposed for third party verifiers. We have no objection to above-mentioned "clearinghouse" role, provided that the role does not substitute for government verification and that all data is publicly available. We nonetheless disagree with EPA's suggestion that with such a clearinghouse, "notifications of well completions could be submitted with an advance period much less than 30 days that could make a 2 day follow-up notification unnecessary."[588] EPA has not explained how the clearinghouse would obviate the need for such advanced notification. Although notification through a clearinghouse might be more efficient than other notification methods, the role of advanced notification is to enable states and EPA to inspect well completions as they occur, and significant advanced notice is likely to facilitate scheduling of such inspections. An online clearing house would not solve this scheduling problem.

The second role EPA suggests for third-party verifiers is to assist states and EPA in "review[ing] and verify[ing]" data submitted through EPA's electronic reporting tool. In light of the conflict of interest mentioned above, private verifiers must not displace government review and enforcement of NSPS requirements. Absent a more definite proposal, we oppose using third-party verifiers in this way.

Third, EPA alludes to using third party verifiers to inspect facilities in the field. This role is implied by EPA's statement that third-party verification can be useful in light of the geographically dispersed and remote nature of facilities, although it is not directly discussed by EPA. Provided that third-party verifiers are limited to collection of unarguably objective data, such as the type of compressor installed, we do not object to this *type* of verification. Nonetheless, because EPA has not proposed a specific framework for verification, and because the implementation details are critically important, we oppose using third party verifiers in this role until EPA offers a more detailed proposal for public comment.

B. The Affirmative Defense

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[587] 76 Fed. Reg. at 52,750.
[588] *Id.*

EPA unlawfully proposes to promulgate an "affirmative defense" to penalties due to a malfunction.[589] This would create a new loophole in the standards and is unlawful. It also would have harmful consequences for local communities affected by oil and gas production, and will greatly reduce the deterrent impact of the proposed standards.

The statute makes clear how the courts are to assess civil penalties, whether a case is brought by EPA or a citizen.[590] Congress plainly intended citizens to be able to enforce emission standards under the CAA using the full range of civil enforcement mechanisms available to the government. EPA's rule proposal, by shifting this careful balance and contravening these mandates, violates the CAA.

The affirmative defense that EPA proposes to allow in case of malfunctions goes directly against congressional intent in two ways. First, Congress expressed a clear intent as to how judges should determine the size of civil penalties whenever they are sought and thus Congress flatly barred EPA from limiting when civil penalties can be assessed.[591] In this proposal, EPA acts outside of its delegated authority to limit civil penalties available in citizen suits or its own enforcement actions. Second, the proposal will impermissibly chill citizen participation, and the ability to win an effective, deterrent remedy, in CAA enforcement actions.

The affirmative defense is fatally flawed because EPA does not have the authority to decide when civil penalties will not be allowed. The CAA itself spells out the only limits that Congress intended to impose on citizens' ability to seek and recover penalties in enforcement suits under CAA § 304, 42 U.S.C. § 7604.[592] By attempting to impose additional agency-created limits, EPA exceeds its authority.

Congressional intent on civil penalties is clear—they are a remedy available for enforcement by citizen plaintiffs, and the Act gives judges a list of factors to consider in assessing them.[593] As such, EPA cannot interpret the statute to contravene that intent.[594] By attempting to rewrite this provision, via regulation, EPA has done just that.

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[589] *See* 76 Fed. Reg. at 52,807 (proposing 40 C.F.R. § 60.5415(h)).
[590] 42 U.S.C. § 7413(e).
[591] *See Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 842-43 (1984), attached hereto as Exhibit 181.
[592] *See* 42 U.S.C. § 7413(e).
[593] *Sackett v. EPA*, 622 F.3d 1139, 1146-47 (9th Cir. 2010) *cert. granted in part,* 131 S. Ct. 3092 (2011) (in interpreting analogous penalty provision of Clean Water Act, 33 U.S.C. § 1319(d) holding that "the civil penalties provision is committed to judicial, not agency, discretion."), attached hereto as Exhibit 182.
[594] *See Chevron*, 467 U.S. at 842-43; *see also Barnhart v. Sigmon Coal Co.*, 534 U.S. 438, 462 (2002) ("We will not alter the text in order to satisfy the policy preferences of the Commissioner."), attached hereto as Exhibit 183; *North Carolina v. EPA*, 531 F.3d 896, 910 (D.C. Cir. 2008) ("All the policy reasons in the world cannot justify an agency reading a substantive provision out of a statute."), attached hereto as Exhibit 184.

The CAA grants EPA minimal discretion that only applies to administrative penalties, allowing EPA to "compromise, modify, or remit, with or without conditions, any administrative penalty which may be imposed under [subsection 113(d)]."[595] However, there is no similar grant of authority to EPA to compromise, modify or limit civil penalties that a court may impose under section 113(e) or section 304. Section 304(a), 42 U.S.C. § 7604(a), grants courts the sole authority "to apply any appropriate civil penalties" in citizen suits. The explicit reference to EPA's ability to modify penalties in one subsection and its absence in the other subsection of the same provision can only be understood as an intentional decision by Congress that EPA may not contravene by rule.

If a local community group sued a covered facility for a violation of the emission standards, the owner might argue that it is exempt from paying civil penalties so long as the owner satisfied the requirements set forth in EPA's proposed affirmative defense regulations.[596] The owner must not be able to evade civil penalties that apply when the congressionally mandated factors in the statute are met.[597,598] It is improper for a court to fail to consider these factors, or to fail to make its own determination of what civil penalties are "appropriate" under CAA § 304(a), and EPA must not ask a court to ignore its legal duty.[599] Notably, courts interpreting the analogous provision of the Clean Water Act have held that the statutorily enumerated factors cannot warrant elimination of a penalty.[600,601] *A fortiori* it is impermissible for EPA to attempt to displace those

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[595] 42 U.S.C. § 7413(d)(2)(B).

[596] *See* 76 Fed. Reg. at 52,813-14, 52,829-30 (proposing 40 C.F.R. §§ 63.761-62, §§ 63.1271-72).

[597] *See* 42 U.S.C. § 7413(e) (listing factors).

[598] Note that the proposed exemption would also be barred under *Chevron* step two or found to be arbitrary and capricious since, even if there exists some slight ambiguity, it is unreasonable to construe the statute as permitting EPA to short-circuit the consideration of specifically listed factors. *See Chevron*, 467 U.S. at 843 (explaining that if the statute does not answer the question at issue, "the question for the court is whether the agency's answer is based on a permissible construction of the statute"); *S. Coast Air Quality Mgmt. Dist. v. EP*A, 472 F.3d 882, 895 (D.C. Cir. 2006) ("We further hold that EPA's interpretation of the Act in a manner to maximize its own discretion is unreasonable because the clear intent of Congress in enacting the 1990 Amendments was to the contrary."), attached hereto as Exhibit 185; *see also Gen. Instrument Corp. v. F.C.C.*, 213 F.3d 724, 732 (D.C. Cir. 2000) (explaining that "an arbitrary and capricious claim and a *Chevron* step two argument overlap"), attached hereto as Exhibit 186; *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (explaining that agency acts in arbitrary and capricious manner if it fails to consider "relevant factors" or "entirely fail[s] to consider an important aspect of the problem"), attached hereto as Exhibit 187. By "upset[ting] the statutory balance struck by Congress," as discussed above, the affirmative defense is unreasonable under *Chevron* step two. *Int'l Alliance of Theatrical & Stage Employees v. N.L.R.B*, 334 F.3d 27, 35 (D.C. Cir. 2003), attached hereto as Exhibit 188.

[599] It is also improper for EPA to fail to consider the section 113(e)(1) factors in situations in which it is setting the penalty. CAA § 113(e)(1), 42 U.S.C. § 7413(e)(1); *see also N.Y. Cross Harbor R.R. v. Surface Transp. Bd*., 374 F.3d 1177, 1184 (D.C. Cir. 2004) (holding that "Board's failure to balance the competing interests . . . requires" vacatur of agency action).

[600] *See United States v. Lexington-Fayette Urban County Gov't*, 591 F.3d 484, 488 (6th Cir. 2010) (collecting cases from the Fourth, Sixth, Ninth, and Eleventh Circuits), attached hereto as Exhibit 189.

factors or in any way alter their significance by creating a bar to penalties if certain agency-defined considerations are met instead.

Citizen participation in CAA enforcement also will be hindered, in violation of citizens' rights to protect themselves from pollution and in direct conflict with congressional intent. The affirmative defense would likely be used on a routine basis by polluters seeking to avoid penalties, just as the malfunction exemption was. As a result, citizens who seek the assessment of civil penalties against polluters in order to protect themselves and achieve the Act's goals may be forced to engage in fact-intensive disputes over the cause of emission violations and adequacy of responsive measures – an outcome Congress intended to prevent with the simple straightforward enforcement and penalty provisions in the Clean Air Act. As a result, enforcement of the Act could suffer, for civil penalties provide a powerful deterrent to violators as Congress intended. As the Supreme Court explained: "To the extent that they [civil penalties] encourage defendants to discontinue current violations and deter them from committing future ones, they afford redress to citizen plaintiffs who are injured or threatened with injury as a consequence of ongoing unlawful conduct."[602,603]

Thus, the affirmative defense also runs counter to two clearly expressed intentions of Congress: (1) the burden it places on citizens makes it less likely that they will enforce the Act;[604] and (2) several of the factors at issue in the affirmative defense undercut Congress's intent that citizen suit enforcement should avoid re-delving into "technological or other considerations."[605] Both result from the technical burden EPA imposes on citizens with the affirmative defense, and both render the defense impermissible.

In addition to these problems, there is simply no need for an affirmative defense to penalties to be written into the regulations and cause the harm that will result. EPA has discretion to decide what cases to prosecute, to consider settlements, and to request

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[601] In another proceeding, EPA has argued that it may promulgate such an affirmative defense as an interpretation of the 'catchall' provision of CAA § 113(e)(1), which directs "the Administrator or the court, as appropriate," to consider the enumerated factors and "such other factors as justice may require." Partial Approval of Texas SIP, 75 FR 68,989, 68,999 (Nov. 10, 2010), attached hereto as Exhibit 190. As noted above, this provision represents a Congressional delegation of discretion to judges, not EPA. *United States v. Mead Corp.*, 533 U.S. 218, 226-27 (2001) (agencies enjoy *Chevron* deference where it is reasonable to presume that Congress delegated interpretive authority to the agency), attached hereto as Exhibit 191. Even if EPA has authority to interpret "other factors," the affirmative defense would require a court to elevate these additional factors above those enumerated by the statute.

[602] *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs.*, 528 U.S. 167, 186 (2000), attached hereto as Exhibit 192.

[603] S. Rep. 101-228, at 373 (1989), *as reprinted in* 1990 U.S.C.C.A.N. 3385, 3756, attached hereto as Exhibit 193.

[604] *See, e.g.*, *Pennsylvania v. Del. Valley Citizens' Council for Clean Air*, 478 U.S. 546, 560 (1986), attached hereto as Exhibit 194.

[605] *NRDC v. Train*, 510 F.2d 692, 724 (D.C. Cir. 1974)

civil penalties in a case-by-case manner, as long as it acts consistent with the Clean Air Act to protect clean air as its top priority.[606] Promulgating this affirmative defense is equivalent to giving polluters "get out of jail free" cards for serious emission exceedances and MACT violations. Polluters are likely to claim that any violation of the standard is due to a malfunction in order to evade the requirements. Allowing polluters to evade financial penalties – which are the real teeth of the standards – through this type of measure is likely to lead to polluters simply ignoring or factoring potential standard violations into their cost of doing business, rather than actually trying to prevent malfunctions and violations of the standards as a way to avoid financial losses from the application of penalties.

Assuming *arguendo* that EPA had authority to promulgate any type of affirmative defense to penalties for malfunctions, EPA is required by statute to also promulgate the following provisions:

1. A specific amount of compensatory penalties must apply to each reported malfunction (consistent with the Act). These funds must be dedicated to enforcement, inspections, and monitoring in the local community around the specific facility, to create greater assurance that malfunctions will not happen again.

2. EPA must modify the regulations so that the affirmative defense cannot be used by a specific facility or company more than once within a set period of time, such as 10 years. The affirmative defense must become automatically unavailable to a facility that has previously had a malfunction within the last 10 years, to ensure that this defense does not swallow the value of the standards.

3. EPA must promulgate specific public reporting and notification requirements for malfunctions, or any emission exceedance that occurs of which an operator is aware. Specifically, EPA must require that when a facility provides EPA with a notification of a malfunction or emission standard exceedance under the regulations, this notice will be made publicly available on EPA's website within 14 days. In addition, EPA must promulgate the requirement that when such notification is made, the facility must also provide for community notification of the malfunction or emission standard exceedance within 2 business days, through an appropriate public forum that is designed to reach residents who live near the facility, including but not limited to a notice on the facility's own website (if it has one), a written notice to the local municipality and local school district, a press release to the local newspaper, radio, and TV news

[606] *See* 42 U.S.C. § 7401.

> station that contains information community members may need to protect themselves and their families from the additional air pollution.

Commenters urge EPA not to adopt an affirmative defense that undermines citizen rights and remedies under the Clean Air Act. People living near oil and gas facilities are exposed to unacceptably high levels of hazardous air pollution that no one should have to face simply because of where they live. EPA may not lawfully use a regulation to take away a right granted to citizens by Congress. EPA must work to expand and protect the ability of people harmed by air pollution to seek all appropriate and available forms of relief in court. EPA must not retract or weaken citizen rights and remedies, as this proposal does, by making it more difficult for people to win meaningful relief from facilities that have released toxic air pollution into their communities for years.

Commenters support EPA's proposal for electronic reporting of data.[607] If EPA were to finalize any form of an affirmative defense, it must require that all reports related to that defense be submitted electronically and EPA must also make these reports available immediately to the public on its website, as discussed above. As the public has a right to all collected reports under the Clean Air Act, 42 U.S.C. § 7414(c), EPA must require immediate disclosure to the public on the Internet, without the need for any person to submit a FOIA request for such a report.

VII. EPA HAS OVERESTIMATED THE COSTS AND UNDERESTIMATED THE BENEFITS OF ITS PROPOSAL

A. EPA's Consideration of Costs Under Section 111 and the Regulatory Impacts Analysis

As we demonstrate above, EPA's proposal is based upon readily achievable methods, the costs of which are reasonable. In this section of our comments, we delve deeper into the costs and benefits of the rule, demonstrating that the rule has significantly greater economic and social benefits than EPA suggests.

EPA must, under section 111 of the Act, issue standards of performance that

> reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the *cost of achieving such reduction* and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[608]

[607] 76 Fed. Reg. at 52,748, 52,825, 52,840.
[608] 42 U.S.C. § 7411(a)(1) (emphasis added).

Under this plain language, EPA must consider the costs of control, i.e., those that the sector incurs to achieve the emission reduction from the affected facility to which the standard applies, in setting a standard of performance; it may not base its standard-setting on a broad-ranging cost-benefit analysis.[609]

Below, we demonstrate that these costs of control are frequently over-stated with respect to the proposal. EPA regularly uses very conservative data to calculate costs. A more realistic assessment would show that the rule has substantially lower costs than EPA acknowledges. We also show that EPA's estimates of the rule's direct financial benefits, through the capture of natural gas and condensate, are low. The natural gas prices EPA uses to calculate these benefits are far lower than all other projections. EPA must use a realistic gas price in its analysis, which would accurately value the savings that the standards will achieve. Doing so will significantly lower the cost of control EPA uses in its standard setting process.

We also address EPA's discussion of the benefits of the rule, which it developed in its Regulatory Impact Analysis (RIA), which did include a cost-benefit analysis, as part of its compliance with Executive Order 12866, "Regulatory Planning and Review."[610] Importantly, while the RIA provides important information on the impacts of the proposed rule, EPA's standard-setting duties and authority are derived under section 111 of the Act and its decision must be made within the confines of that authority, although it may be described and informed by the RIA.[611] As such, our critique of the RIA largely addresses how EPA and other government actors are to understand the economic impact of the rule. It does not bear directly on the standard setting process itself.

With regard to the RIA, we show that EPA has not properly accounted for the substantial benefits the rule creates by capturing methane as a co-benefit of VOC regulation. These co-benefits include both substantial reductions in climate change-causing pollution, and a reduction in ground-level ozone, of which methane is a precursor. While EPA provided an estimate of the climate-linked financial benefits of the methane reductions in the RIA (an estimate of the "social cost" of methane), it chose "not to compare these co-benefit

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[609] *Id.; see also Motor & Equipment Mfrs. Assn. v. EPA*, 627 F.2d 1095, 1117-18 (D.C. Cir. 1979) (in interpreting "cost of compliance" for vehicle emission standards under section 202(a)(2), rejecting industry's claim that EPA must consider broad social costs), attached hereto as Exhibit 195; *American Textile Manufacturers Inst. v. Donovan*, 452 U.S. 490, 510-11 (1981) (explaining that "Congress uses specific language when intending that an agency engage in cost-benefit analysis."), attached hereto as Exhibit 196. We note that section 111(h) imposes identical cost of control considerations upon EPA, and so our discussion of the cost of control of EPA's standards applies to those controls as well. *See* 42 U.S.C. § 7411(h)(1).

[610] *See* 76 Fed. Reg. at 52,794 (citing 58 Fed. Reg. 51,735 (Oct. 4, 1994)).

[611] *See* E.O. 12866 Section 10, "Judicial review," attached hereto as Exhibit 197. "Nothing in this Executive order shall affect any otherwise available judicial review of agency action. This Executive order is intended only to improve the internal management of the Federal Government and does not create any right or benefit, substantive or procedural, enforceable at law or equity by a party against the United States…."

estimates to the costs of the rule for this proposal," but rather only to explore methane co-benefits in supporting documents as an "interim method."[612] For the reasons set forth below, we believe that EPA must include the methane co-benefits in its comparison of the proposed rule's costs and benefits. We also propose ways in which the social-cost-of-methane assessment can be improved by EPA in this rulemaking, and corrections and improvements to the underlying "social cost of carbon" analysis that should be made by the Interagency Working Group on the Social Cost of Carbon. We also discuss substantial ozone reduction co-benefits that will occur with the methane reductions, which will produce substantial public health and welfare improvements. Without these corrections and improvements, the figures provided by EPA significantly underestimate the social benefits of methane reductions from the proposed rule.

B. EPA Overestimated the Costs of Its Proposed Rule

1. The Costs of the Standards are Reasonable Under Section 111

In its evaluation of costs supporting the proposed rule under section 111, EPA assessed the cost of control for various affected facilities and technologies, finding the costs associated with each adopted measure to be reasonable. It then took into account, for control technologies capturing natural gas, the additional savings due to resale of captured gas where such resale is feasible. We compared these EPA estimates to figures from other EPA reports and industry information, and generally conclude that EPA's estimates range from reasonable to very conservative. In some instances, EPA overestimates the cost of control; in others, it underestimates the volume of gas reduced for a given cost; and in some cases it both overestimates the costs and underestimates the emissions controlled. When added to EPA's underestimation of the price of natural gas, taking account of these factors supports that the proposed rule's costs are lower than EPA recognizes.

Our focus throughout is upon the cost per ton of emission reduction, as this is the metric that EPA used to show that the proposed standards impose reasonable costs, consistent with section 111's required considerations.[613]

Our assessment is based on:

- Quantitative cost of control comparisons between EPA's estimates and other estimates, by control technology;
- Qualitative considerations that contextualize and add to the above comparisons; and

[612] RIA at 4-33.
[613] We do not necessarily agree that a dollars-per-ton-of-pollutant-controlled metric is the appropriate gauge for costs under section 111(a)(1), as some measures may impose reasonable costs within the meaning of the statute even if they exceed some EPA threshold for cost effectiveness.

- Analysis of the forecasted price of natural gas forecasted, and its divergence from EPA's estimate.

Although we have done our best to unpack EPA's assumptions, EPA's cost calculations and methodology are not transparent. EPA must more clearly describe its "cost of control" methodology in the final rule, including its calculations and sources.

2. Quantitative comparison of the cost of control technologies

For each technology, we have compared available EPA TSD estimates to other sources, including: Past EPA reports and presentations particularly related to its Natural Gas STAR program; EPA's Methane to Markets Partnership (recently transformed into the Global Methane Initiative) presentations derived from methane reduction successes in the US and thirteen other countries; independent company reports; independent consultant reports; and journal publications.

Different data sources and analyses report costs in different ways (e.g., yearly profit, net present value, payback). We have tabulated the available data to facilitate a like-for-like comparison. Where helpful, we have translated reported data in ways that best fit into the table. But, in many instances the available information was insufficient to populate the entire cost-effectiveness breakdown; in these instances, we have still included all available data. Where possible, we estimated cost per year (or per device, as applicable), savings per year (or per device), profitability per year (or per device) and the payback of the investment. We used the latter two metrics as prime indicators of the cost-effectiveness of the control technologies. These are highlighted in the tables below.

For natural gas prices, where data for the volume of natural gas savings was available, we assumed the price of natural gas to be $4/Mcf, to align with EPA's calculations. When volumes were not directly available in the data sources, in most cases we scaled these savings to what the savings would have been at a natural gas price of $4/Mcf. In some cases, we had insufficient data or visibility to scale the savings and left it unaltered (but in these instances noted the likely price of natural gas applicable). Later in this document, we discuss the likelihood of prices being different from $4/Mcf.

We make a general observation here that in several instances we have quoted from EPA and other reports from the recent past. Despite having been published as much as five years ago, these reports are valuable because they provide transparent and well-documented examples of cost-effective and profitable emissions reductions that have been achieved. In contrast, we find in general that the EPA TSD estimates lack transparency. In a few instances, sources for the analysis are not entirely clear. In other instances where sources are mentioned, the additional analysis conducted using those sources are not sufficiently explained to facilitate independent verification. In yet other instances, it is unclear whether some of the estimates are based on past achievements. Additionally, as explained in more detail in following sections, the estimates from past

reports provide numerous examples of controls being much more cost-effective than the EPA TSD estimates, suggesting, by contrast, that the latter is conservative.

a. Green Completions

We assess EPA's estimated cost of control of green completions to be reasonably realistic.

Table 4: Cost of control analysis of well completions and recompletions

			#	$	Mcf	$ / Mcf	$	$	$ / well	Years	$ / well
Source	**Year**	**Type**	**# wells**	**Total cost per well (capital, operational)**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Condens-ate savings**	**Total revenue per well**	**Payback**	**Profit per well**
EPA - NSPS TSD [614]	2008	Min	1	2,418							
EPA - NSPS TSD	2008	Max	1	74,860							
EPA - NSPS TSD	2008	Average	1	29,713	8,258 [a]	4.00	33,032	2,380	35,412	0.84	5,699
EPA,[615]	2005	Min	1	7,000	7,700	4.00	30,800		30,800	0.23	23,800
EPA	2005	Max	1	15,000	7,700	4.00	30,800		30,800	0.49	15,800
Devon Energy [617,618]	2004	Average	~400[b]	8,700	11,740	5.00	58,700		58,700	0.15	50,000
BP [619,620,621]	2007	Average	106	12,264	7,500	4.00	30,000	6,321	36,321	0.35 - 0.70	24,057
Williams [622]	2006	Average	1177	14,444	22,515	4.00	90,059 [c]		90,059	0.16	75,616

EnCana [623]	??	Average	??	??			??		??	< 1.00	190 M + over many wells
Anadarko [624]	2008	Average	613			5.00	??		??		16,803
ICF [625]	2009	Average	??							0.25	

[a] 142.7 tons of methane; production quality natural gas is approx. 83% methane (EPA TSD page 5-16); 0.0208 tons per Mcf
[b] Calculated from estimated average emissions per well, given that total emissions reductions was ~4.8 Bcf in 2005
[c] Scaled down from revenues based on a historically higher natural gas price, assumed to be $6/Mcf

In its NSPS Technical Support Document (TSD)[614], EPA estimates that the average green completion costs about $29,700 per completion, and saves approximately 8,300 Mcf of natural gas per completion (valued at $33,000, at $4/Mcf) and a modest volume of condensates.

Based on recent estimates from select company operations and EPA's 2005 reports of achieved emissions reduction,[615] we estimate that a green completion would typically cost $7,000 - $15,000 per completion. The savings from captured natural gas vary quite significantly among different company reports. We note that the average natural gas savings of 7,700 Mcf of natural gas per well from EPA's 2005 estimates is consistent with the EPA TSD's average savings estimates.

Many different companies[616] have reported profitable use of green completions, although the magnitude of profitability varies:

- In 2004, Devon Energy reported an average incremental cost to perform a green completion of $8,700 per well at its Texas Fort Worth Basin operations. Devon estimated that after paying out this cost, it yielded a profit of $50,000 per well by selling the captured gas to market, estimating that it achieved a total emission reduction of 6.16 Bcf at its operations in year 2005; 78 percent of the methane captured (4.8 Bcf) was attributed to green completion methods.[617,618]
- BP reported an initial investment cost of $1.4 million to purchase a portable three-phase separator, sand trap, and tanks to conduct green completions.[619] By 2005, BP completed 106 wells using this equipment and reported an average gas recovery of 0.35 Bcf/year and condensate recovery of 6,700 bbls/year. The company's investment paid out in nearly two years; thereafter, the equipment

[614] EPA NSPS TSD, pages 4-15 – 4-18.
[615] EPA Natural Gas STAR, *Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas*, November 1, 2005, attached hereto as Exhibit 198. EPA reports costs of $1,000 to$10,000 per well (in November 2005 document). However, the costs use in this report are higher ($7,000 - $15,000 per well), and more conservative, because this data relies on cost estimates provided by Devon, BP and Williams operating experience (in New Mexico).
[616] Some of these individual reports may have been included as part of EPA's industry-wide statistics, but there remains some uncertainty as to whether and how these examples have been assimilated, Therefore these examples serve as specific instances of the successful implementation of these technologies.
[617] EPA, ExxonMobil Production Company, and American Petroleum Institute, Green *Completions, Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop*, September 21, 2004, attached hereto as Exhibit 199.
[618] Devon Energy, *EPA Natural Gas STAR Program Presentation*, March 2007, attached hereto as Exhibit 200.
[619] EPA and Devon Energy, *Reduced Emissions Completions (Green Completions), Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop*, Casper, Wyoming, August 30, 2005, attached hereto as Exhibit 201.

netted a profit of at least $840,000 per year.[620] Later, in 2007, BP reported that green completions had netted a profit of $3.4 million, for an investment of $1.2 million, with a payout of 0.7 years, and a capture of 130 Mt of methane per well.[621]

- Williams reported $159 million in revenue from green completions in its Colorado Piceance Basin Operations from 2002 to 2006, spending $17 million to achieve that revenue, for a net profit of $142 million.[622] Assuming these savings were on average due to a natural gas price of $6/Mcf, the savings have been scaled down for a $4/Mcf price. Williams' economic data was based on 1,177 wells and an average gas recovery of approximately 91 percent.
- EnCana Corporation, the largest natural gas producer in North America, reported results from its Jonah Field in Wyoming. Jonah produces 1.5 percent of United States daily gas needs. EnCana reported[623] that green completion methods were extremely profitable in the Jonah field, yielding a Net Present Value (NPV) of more than $190 million. EnCana's initial investment in the portable REC equipment for the Jonah Field paid out in the first year.
- Anadarko reported an increased operating profit of $10.3 million/year for the period of 2006 to 2008 due to green completions on an average of 613 wells per year. [624] Anadarko based these calculations on a $5/Mcf natural gas price.
- In a 2009 study conducted for New York State, ICF Incorporated found that equipment payouts were as short as three months. ICF also found that companies made more than $65 million in profits when they elected to conduct green completions in 2005.[625]

In sum, our analysis shows that EPA's well profitability and payback assessments are reasonably realistic, even slightly conservative. The TSD has generally slightly higher estimates of the cost of Green Completions than other sources listed in Table 1. The natural gas savings estimates are roughly consistent with other estimates, which in effect include surveys of over 2,000 wells. We underscore that Green Completions are profitable with an average payback of less than one year.

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[620] BP's profit was based on gas at $1.99 Mcf and condensate at $22/bbl. Gas and condensate prices are substantially higher in 2010; thus, this is a very conservative profit estimate.

[621] Gordon Reid Smith, Natural Gas Industry Green House Gas Control & Business Opportunity, Presentation, 2007, attached hereto as Exhibit 202.

[622] The Williams Companies, "Reducing Methane Emissions During Completion Operations – Economics Volume Recovered." Williams Production RMT – Piceance Basin Operations. 2007 Natural Gas Star - Production Technology Transfer Workshop. September 11, 2007, attached hereto as Exhibit 203.

[623] EPA and ICF International, Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry, 2009, attached hereto as Exhibit 204.

[624] Methane to Markets, Reduced Emission Completions/Plunger Lift and Smart Automation, Oil & Gas Subcommittee Technology Transfer Workshop, Monterrey, Mexico, January, 2009.

[625] ICF Incorporated, Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program, prepared for New York State, August 5, 2009, attached hereto as Exhibit 205.

b. Low-Bleed Pneumatic Controllers

We assess EPA's estimated cost of control of low-bleed pneumatic controllers to be reasonably realistic.

Table 5: Cost of control analysis of replacing high-bleed pneumatic controllers with low-bleed pneumatic controllers

			#	$	$ / yr	Mcf	$ / Mcf	$ / yr	$ / yr	$ / yr	Years	$ / yr
Source	**Year**	**Type**	**# devices**	**Total cost per device**	**Annualized cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Maintenance, operational savings per year**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA - NSPS TSD [626]	2008	Min	1	158	23[a]							
EPA - NSPS TSD	2008	Max	1	1,852	264							
EPA - NSPS TSD	2008	Average	1	165	24	375[b]	4	1,500		1,500	0.11	1,477
EPA [627,628,629]	2005	Average	1	250[c]	36	180[d]	4	720	1,100	1,820	0.15 - 0.40[e]	1,784
EPA Lessons Learned[630]	2006	Average	1	275[f]	39	125[g]	4	500	50	550	0.50	511
BP [631]	2005	Average	11,500	174[c]	25	296[h]	4	1,183	726	1,909	0.09	1,884

[a] EPA assumes a lifetime of 10 years and a discount rate of 7% (NSPS TSD page 5-16, 5-17)
[b] Using the average value of $ savings (NSPS TSD page 5-16); calculated natural gas volume is consistent with TSD value quoted
[c] Assumes half the value of a retrofit
[d] Based on average natural gas savings of 0.5 Mcf/day (as reported in sources)
[e] Range between calculated value and half the reported value of 9 months for a retrofit
[f] Average of $210 and $340 per device
[g] Average of 50 and 200 Mcf/year
[h] 11,500 wells saved 3.4 Bcf/year

In its NSPS TSD,[626] EPA analyzes the costs for a range of low-bleed and high-bleed pneumatic controllers, and estimates that the average cost of a low-bleed pneumatic controller is $165 more per controller than an equivalent high-bleed pneumatic controller. This is the differential cost of installing low-bleed devices instead of high-bleed devices. EPA also estimates an average of $1,500 per year in natural gas savings from reduced emissions per controller.

Our estimates were based on retrofitting or replacing high-bleed with low-bleed pneumatics, due to the availability of data for these scenarios. These projects would cost more than simply choosing low-bleed equipment instead of high-bleed equipment at a new installation. We assumed that the total cost of retrofitting pneumatics was two times the differential cost of installing a low-bleed device instead of a high-bleed device. In order to facilitate a like-for-like comparison with EPA's estimates, we thus divided the retrofit/replacement costs by two to compare to EPA's figures. This is likely to be a conservative estimate.

Based on EPA reports from 2005, retrofitting a high-bleed pneumatic with a low-bleed pneumatic device costs an estimated $500 per controller on average and has a payback of 9 months. The average annual natural gas savings are about $700, and operational savings are conservatively on average $500 per controller.[627,628,629] Operational savings arise mainly from reduced maintenance costs for low-bleed devices. For instance, high-bleed devices tend to be based on older technology and require more maintenance. Also, if operated in enclosed environments high-bleed devices may present a safety hazard and require regular monitoring. The retrofit or complete replacement of worn units can provide better system-wide performance and reliability, and improve monitoring of parameters such as gas flow, pressure, or liquid level.

An EPA Lessons Learned report from 2006 also reports economics consistent with the above, but with smaller operational and maintenance savings. [630] The EPA TSD's overall economic estimates that are derived from this Lessons Learned document, are more positive than estimates directly from the Lessons Learned document due to updates from vendor research.

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[626] EPA NSPS TSD, pages 5-14 – 5-16.

[627] USEPA and Occidental Oil & Gas Corporation, *Methane to Markets, Methane Recovery from Pneumatic Devices, Vapor Recovery Units and Dehydrators*, October 6, 2005, attached hereto as Exhibit 206.

[628] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[629] Journal of Petroleum Technology, *Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers*, June 2005, attached hereto as Exhibit 207.

[630] *Lessons Learned from Natural Gas STAR Partners – Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, 2006, attached hereto as Exhibit 208.

BP has reported that it replaced 11,500 high-bleed pneumatic instruments with low- or no-bleed instruments in six states, during the period of 1999 to 2002, capturing 3.4 Bcf/year.[631] The program yielded a net present value of $65 million for a capital investment of $4 million for all 11,500 controllers.

In sum, we find that EPA's cost, cost-effectiveness, profitability and payback assessments are broadly consistent with our estimates, and we consider EPA's estimates to be realistic, so as to support low-bleed pneumatic controllers as the basis for the final performance standards. We note however that our estimates may be slightly conservative as they are based on half the cost of retrofitting or replacement, which is probably higher than the cost of installing a low-bleed device instead of a high-bleed device. Importantly, the data generally supports that replacing high-bleed with low-bleed devices is highly profitable with a very short payback, sometimes within a small number of months.

c. Instrument Air Pneumatic Controllers

We assess EPA's estimated cost of control of conversion to instrument air pneumatic controllers to be conservative. EPA's proposal is better supported than the agency acknowledges.

[631] Gordon Reid Smith, Natural Gas Industry Green House Gas Control & Business Opportunity, Presentation, 2007.

Table 6: Cost of control analysis of replacing high-bleed pneumatic controllers with instrument air pneumatic controllers

			#	$	$ / yr	$ / yr	$ / yr	Mcf	$ / Mcf	$ / yr	$ /yr	Years	$ / year
Source	**Year**	**Type**	**# devices**	**Total capital cost per device**	**Annual. capital cost of device**	**Maint., operational cost per year**	**Annual. total cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Annual. profit per year**
EPA - NSPS TSD [633]	2008	Small	1	16,972	2,416[a]	1,334	11,090[b]	871	4	3,484	3,484	(3.27)	(7,606)
EPA - NSPS TSD	2008	Medium	1	73,531	10,469	4,333	36,877	3,658	4	14,632	14,632	(6.24)	(22,245)
EPA - NSPS TSD	2008	Large	1	135,750	19,328	5,999	80,515	10,161	4	40,644	40,644	(6.61)	(39,871)
EPA - NSPS TSD	2008	Simple average	1	75,418	10,738	3,889	42,827	4,897	4	19,587	19,587	(6.03)	(23,241)
EPA NG STAR [628,629]	2005	Average	1	10,000	1,400	7,500[c]	8,900	5,400	4	21,600	21,600	0.70 - 2.00[d]	12,700
EPA Lessons Learned[632]	2006	Average	1	60,000	8,500	17,700	26,200	20,000	4	80,000	80,000	0.96	53,800

[a] EPA assumes a 10-year life, and a 7% discount rate
[b] The total annualized cost includes capital, labor and electrical power
[c] Includes both labor and operational costs such as electrical power (unlike EPA costs above in same column)
[d] Range between calculated value and reported value

[632] *Lessons Learned from Natural Gas STAR Partners – Convert Gas Pneumatic Controls to Instrument Air,* 2006, attached hereto as Exhibit 208.

In its NSPS TSD,[633] EPA estimates that the capital cost of conversion to instrument air pneumatics, depending on the size, ranges from about $17,000 to $135,000 per controller, along with sizeable yearly maintenance and operational costs. The natural gas savings increase with the size of the pneumatic controller. However, according to the TSD, the savings are not enough to recover the cost of operating and maintaining the devices. As a result, for all device sizes, the devices have a negative annualized profit (which includes the annualized capital cost). Accordingly, EPA states that the investments do not pay back.

This is in contrast to EPA's 2005 assessment based on Natural Gas STAR program experience.[628, 629] There, the average cost of installing an instrument air device was $10,000 with an average $7,500 expenditure in annual maintenance and operations per controller. The average total cost estimate was even smaller than EPA TSD's small-scale device estimates. Also, in proportion to the investment cost, the 2005 EPA estimate of the natural gas savings was much larger in magnitude. Consequently, this rendered instrument air implementation profitable and the investment paid itself back in less than two years.

Similarly, EPA's estimates are in contrast to EPA's Natural Gas STAR Lessons Learned from 2006.[634] In that report, the capital and installation cost of the device was larger at $60,000 per controller. But the natural gas savings were commensurately larger to render the investment profitable with a payback period of about one year. We further note that the EPA TSD based its estimates on the 2006 Lessons Learned document (above). While the cost of implementation estimates are consistent between the two sources, the EPA TSD's revenue estimates are much lower than those in the Lessons Learned document. For instance, the Lessons Learned document estimates average natural gas savings of about 23,000 Mcf/year for medium-sized controllers and about 20,000 Mcf/year on average. In contrast the EPA TSD estimates for medium-sized controllers are 5-6 times lower. The reason for this has not been made sufficiently clear, and EPA must clarify its rationale.

In sum, our analysis shows that the EPA TSD's cost estimates for instrument air pneumatic controllers may have been somewhat overestimated. Also, it is unclear why the EPA TSD's revenue estimates are lower than in other reports. EPA must provide further clarification in both these regards. In the absence of such explanation, we consider the overall economic estimates made in the EPA TSD to be potentially conservative.

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[633] EPA NSPS TSD, pages 5-19 – 5-22

[634] *Lessons Learned from Natural Gas STAR Partners – Convert Gas Pneumatic Controls to Instrument Air*, 2006. attached hereto as Exhibit 209.

d. Reciprocating compressors

We assess EPA's estimated cost of control and cost-effectiveness of replacing worn rod packing in reciprocating compressors to be potentially conservative. EPA's proposal is better supported than the agency acknowledges.

Table 7: Cost of control analysis of replacing rod packing in reciprocating compressors

			#	$	$ / yr	Mcf	$ / Mcf	$	$ / yr	Years	$ / yr
Source	**Year**	**Type**	**# devices**	**Total cost per packing**	**Annualized cost of packing**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA – NSPS TSD [635]	2008	Production	1	6,480	2,493	9[a]	4	36	36	180.00	(2,457)
EPA – NSPS TSD	2008	Gathering, Boosting	1	5,346	1,669	396[a]	4	1,584	1,584	3.38	(85)
EPA – NSPS TSD	2008	Processing	1	4,050	1,413	1,077[a]	4	4,308	4,308	0.94	2,895
EPA – NSPS TSD	2008	Transmission	1	5,346	1,669	1,257[a]	-	-	-	NA	(1,669)
EPA – NSPS TSD	2008	Storage	1	7,290	2,276	1,263[a]	-	-	-	NA	(2,276)
EPA – NSPS TSD	2008	Simple average	1	5,702	1,904	296	4	1,186	1,186	4.81	(718)
JPT	2008	Average	1	4,800[b]	1,847[c]	3,504[d]	4	14,016	14,016	0.34	12,169
EPA Lessons Learned Error! Bookmark not defined.	2006	Average	1	6,480[e]	2,493[c]	3,460	4	13,840	13,840	0.47	11,347

[a] EPA NSPS TSD, page 6-15, Table 6-6; based on individual compressor emissions reductions in tons per year

[b] Cost of replacing rod packing for four cylinders (as per EPA TSD estimate of average number of reciprocating compressor cylinders in the production sector, Table 6-2), at $1,200 per cylinder

[c] Using same capital recovery factor as used in the EPA TSD for reciprocating compressors in the production sector (EPA TSD Table 6-2)

[d] Multiplying estimated emissions savings as reported by sources by 4, to account for savings from 4 cylinders

[e] Cost of replacing rod packing for four cylinders (as per EPA TSD estimate of average number of reciprocating compressor cylinders in the production sector, Table 6-2), at $1,620 per cylinder

In its NSPS TSD,[635] EPA estimates that replacing rod packing costs between $4,000 and a little over $7,000 per rod packing replacement. The natural gas savings depends on which stage of the natural gas system the device operates. According to the TSD, the most profitable device is in the processing stage where it has an annualized profit (which includes the annualized capital cost) of about $2,900 per compressor and a payback of 1 year. EPA also found in the TSD that some of the less profitable devices are not profitable enough to pay back even the initial investment.

In our two references, the cost of replacing the rod packing is largely consistent with EPA TSD's estimates. We note that one of the references[636], the EPA Natural Gas STAR Lessons Learned 2006 document, is the same as the one that the EPA TSD states that it obtained its cost estimates from. The other reference[637] notes a slightly lower cost for replacing rod packing.

However, when it comes to annual natural gas revenues from sales, the EPA TSD's estimates indicate that there are almost negligible revenue from the production sector (less than $50), about $1,500 of revenue from the gathering and boosting sectors, about $4,300 of revenue from the processing sector. The rationale for this variation, amongst what appear to be similarly-sized compressors, is not entirely elucidated by EPA. The variation is counter to average industry estimates reported in our references (one of which is even used by the EPA TSD), which do not identify different natural gas revenues in different sectors. Importantly, the natural gas revenues reported in our references is significantly larger than those in the EPA TSD.

As a result, our estimates indicate that replacing rod packing systems in all the three sectors mentioned above would be profitable and have a reasonable cost of control. We note that even the EPA TSD's most profitable compressor (in the processing sector) is much less profitable than our estimates.

In sum, our analysis shows that the EPA TSD's estimates for the cost of replacing rod packing systems are consistent with ours. We request the EPA to further explain why the natural gas revenue estimates are so different in the different sectors and lower on the whole than other references, and to revise its figures appropriately. In the absence of this explanation we consider the overall economic estimates made in the EPA TSD to be potentially conservative.

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[635] EPA NSPS TSD, pages 6-15 – 6-18.

[636] *Lessons Learned from Natural Gas STAR Partners – Reducing Methane Emissions from Compressor Rod Packing Systems*, 2006.

[637] Journal of Petroleum Technology, *Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers*, June 2005.

e. Compressors with dry seals

We assess EPA's estimated cost-effectiveness of replacing wet seals in centrifugal compressors with dry seals to be conservative. EPA's proposal is better supported than the agency acknowledges.

Table 8: Cost of control analysis of replacing wet seals in centrifugal compressors with dry seals

			#	*$*	*$ / yr*	*Mcf*	*$/Mcf*	*$*	*$/year*	*$ /yr*	*Years*	*$ /yr*
Source	**Year**	**Type**	**# devices**	**Total cost per device**	**Annual. cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Maint., operational savings per year**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA – NSPS TSD [638]	2008	Processing	1	75,000[a]	10,678[b]	11,527[c]	4	46,108	88,300	134,408	0.56	123,730
EPA – NSPS TSD	2008	Trans. / Storage	1	75,000	10,678	6,372[c]	-	-	88,300	88,300	0.85	77,622
EPA – NSPS TSD	2008	Simple average	1	75,000	10,678	8,949		23,054	88,300	111,354	0.67	100,676
EPA NG STAR [639,640]	2009	Average	1	162,000[d]	23,064[e]	50,000	4	200,000[f]	120,000[g]	320,000	0.51	296,936
Petroleos Mexicanos [641]	2008	Average	1			35,000	4	140,000	??	140,000+	??	126,690
Targa [642]	2006	Average	1	90,000	12,814			??	??	300,000	0.38[h]	287,186

[a] EPA reports this to be 1-3% of the total pipeline cost
[b] EPA assumes a 10-year life and a 7% discount rate
[c] EPA NSPS TSD, page 6-20, Table 6-8; based on individual compressor emissions reductions in tons per year
[d] Assumes half the value of a retrofit
[e] For annualized capital cost, assumes similar lifetimes and discount rate as in EPA's estimates
[f] Conservative low estimate of natural gas savings based on the range of savings from $75,000 - $400,000
[g] Average maintenance and operational savings of $120,000 based on the range of savings of $100,000 - $140,000
[h] Average of 2 – 7 months

In its NSPS TSD,[638] EPA estimates the incremental capital cost of newly installing centrifugal compressors with dry seals instead of centrifugal compressors with wet seals at $75,000 on average. This is the cost of installing a new dry seal compressor instead of a new wet seal compressor. EPA further assumes annual operational savings of $88,300 and additional annual natural gas revenue of approximately $46,000 per compressor from compressors in the processing stage, but no additional revenue in the transmission / storage stage. This is equivalent on average (simple average) to an annualized profit (which includes annualized capital costs) of about $100,000 and a payback period of about 8 months (0.67 years) per new compressor with dry seals instead of wet seals.

According to EPA Natural Gas STAR 2009 reports,[639] a dry seal retrofit (generally more expensive than a new installation) costs $324,000 per compressor on average, with annual operational savings of $100,000 - $140,000 and additional revenues of ranging from $75,000 to $420,000[640] per compressor. A conservative average annual revenue from natural gas of $200,000 per compressor was assumed here. Operational savings are expected from reduced downtime due to less required maintenance, improved compressor reliability, reduced power requirements and elimination of seal oil costs. The average operational savings and additional revenue are noted to be higher than EPA's NSPS TSD estimates. Furthermore, conservatively assuming that the incremental capital cost of a dry seal compressor versus a wet seal compressor is as much as half the cost of a retrofit, the payback period for a dry seal investment instead of wet seal is just over half a year.

In 2008, Petróleos Mexicanos (PEMEX) assessed the benefits of converting from wet seals to dry seals on centrifugal compressors at a compression station in southern Mexico. It found gas savings of 33.5 scfm per seal, and gas savings of 35 MMcf/year, resulting in a profit of $126,690 per year.[641]

Targa Resources and the Gas Processors Association report that replacing a wet seal with a dry seal on a six-inch shaft beam compressor that operates approximately 8,000 hours per year, leaking at 40 - 200 scfm, will pay back in 4 to 15 months, yielding more than $1 million in NPV, assuming a 10 percent discount rate in a span of five years, and

[638] EPA NSPS TSD, pages 6-19 – 6-22.
[639] EPA Natural Gas STAR, *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*, EPA 430-B-03-012, 2009.
[640] EPA 2011 GHG inventory leak rates: emission estimates used a leak rate of 2125 scfh, (18,600 Mscf/year) equivalent to approximately $75,000 of gas leaking from each compressor each year it is not repaired. EPA estimates that some wet seal compressor leaks can be as high as 200 scfm (105,000); approximately $420,000 of gas leaking from each compressor each year it is not repaired. This assumes a natural gas price of $4/Mcf.
[641] Methane to Markets, Natural Gas STAR International, *Reducing Emissions, Increasing Efficiency, Maximizing Profits*, epa.gov/gasstar/international/index.html, 2008, attached hereto as Exhibit 210.

more than a 170 percent rate of return.[642] The payback period here is for a retrofit. Again, conservatively assuming that an incremental investment in a dry seal compressor is as much as half the cost of a retrofit, the payback period may be expected to halve to 2 – 7 months.

In sum, we consider EPA to have underestimated the average operational savings and the emissions reductions (and so additional natural gas revenue) from the average investment analyzed, leading to conservative cost-effectiveness, profitability, and payback estimates..

f. Tank Vapor Recovery Units

We assess EPA's estimated cost of control and cost-effectiveness of installing tank vapor recovery units to be overly conservative. EPA's proposal is better supported than the agency acknowledges.

[642] Targa Resources and the Gas Processors Association, Methane Savings from Compressors and VRUs, Innovative Technologies for the Oil & Gas Industry: Product Capture, Process Optimization, and Pollution Prevention, July 27, 2006

Table 9: Cost of control analysis of installing vapor recovery units

				$	$ / yr	$ / yr	$ / yr	Mcf	$/Mcf	$	$ / yr	Years	$ / yr	$ / yr
Source	**Year**	**Type**	**# dev.**	**Total capital cost per device**	**Annual. capital cost of device**	**Maint., oper. costs per year**	**Annual. total cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Oper. profit per year**	**Annual. profit per year**
EPA [643]	2008	Average	1	98,186	10,780 [a]	9,367	20,147	291	4	1,164	1,164	negative	(8,203)	(18,983)
EPA NG STAR [644]	2010	Small scale	1	35,738 [b]	3,924 [c]	7,367	11,291	4,566	4	18,262 [d]	18,262	3.28	10,895	6,972
EPA NG STAR	2010	Medium scale	1	55,524	6,096	10,103	16,199	18,262	4	73,048	73,048	0.88	62,945	56,849
EPA NG STAR	2010	Large scale	1	103,959	11,414	16,839	28,253	91,311	4	365,242	365,242	0.30	348,403	336,990
EPA NG STAR	2010	Simple average	1	65,074	7,145	11,436	18,581	38,046	4	152,184	152,184	0.46	140,748	133,603
Anadarko [644]	1999	Average	300										4,167	
ConocoPhillips [644]	??	Average	9	79,167	8,692 [c]							0.33	252,000	243,308
Chevron [646]	1996	Average	8									<1		

[a] EPA assumes a 15-year life and a 7% discount rate

[b] This includes capital cost and installation cost equal to 75% of the capital cost

[c] For annualized capital cost, assumes similar lifetimes and discount rate as in EPA's estimates
[d] Scaled down from savings based on a historically higher natural gas price of $6.22/Mcf

In its NSPS TSD,[643] EPA estimates the capital costs of installing a vapor recovery unit on storage vessels at $98,186, with an additional $9,367 in annual operational and maintenance expenses. According to the TSD, the additional revenue from captured natural gas is $1,164 per vapor recovery unit per year, leading to an annualized loss of $18,893 per unit. Also, due to an annual operating loss on the vapor recovery unit (i.e., operational and maintenance expenses exceed additional natural gas revenue), the TSD concludes that the investment does not pay itself back.

Yet, according to EPA's 2010 report on earnings from Natural Gas STAR programs,[644] vapor recovery projects of various sizes can be profitable with payback periods ranging from a few months to about three years. Natural gas savings were calculated based on a price of $6.22/Mcf; accordingly savings reported here have been scaled down for a natural gas price of $4/Mcf. Even so, we note that even the least-profitable small-scale vapor recovery units generated more revenue from natural gas savings than associated operational and maintenance costs, to yield a net annual operating profit and a consequent investment payback of 3.28 years. Larger tank vapor recovery units had much stronger profitability, with the largest units paying back in 3 - 4 months.

Additional examples of tank vapor recovery profitability include:

- Anadarko reported netting $7 million to $8 million between 1993 and 1999 by installing more than 300 vapor recovery units.[644]
- ConocoPhillips installed vapor recovery on nine tank batteries at a total cost of $712,500. The company's investment paid back within 4 months, earning $189,000 per month thereafter.[645]
- Chevron installed eight vapor recovery units on crude oil stock tanks in 1996; this investment paid back in less than one year.[646]

In sum, we consider EPA's estimates of the cost-effectiveness and profitability of vapor recovery units to be very conservative. In our assessment this is primarily due to the TSD's exceedingly low estimates of natural gas savings from vapor recovery units, which are at least 25 times lower than other reports of vapor recovery units in operation. As we discuss below, these savings are properly considered in the BSER analysis.

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[643] TSD at 7-13 – 7-14.

[644] EPA Natural Gas STAR, *Reducing Methane Emissions with Vapor Recovery on Storage Tanks, Lessons learned from the Natural Gas STAR Program*, Newfield Exploration Company, Anadarko Petroleum Corporation, Utah Petroleum Association, Interstate O&G Compact Commission, Independent Petroleum Association of Mountain States, March 23, 2010, attached hereto as Exhibit 211.

[645] *Id.*

[646] Richards, L.S., Hy-Bon Engineering, Co., *Fundamentals of Vapor Recovery, Associated Gas is Lost Product and Lost Revenue*, October 2005, attached hereto as Exhibit 212.

g. Leak Detection and Repair

We assess EPA's estimated cost of control, cost-effectiveness and profitability of conducting leak detection and repair to be potentially conservative. EPA's proposal is better supported than the agency acknowledges.

Table 10: Cost-effectiveness of leak detection and repair systems

				$	*$/year*	*$ / year*	*Mcf*	*$/Mcf*	*$*	*$ /yr*	*Years*	*$ /yr*
Source	**Year**	**Type**	**# devices**	**Total capital cost per device**	**Maint. oper. per year**	**Annual. total cost of device**	**Vol. of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA - NSPS TSD [649]	2008	Valves	1	18,529 [a]	incl. in total	34,608	1,060 [a]	4	4,241	4,241	negative	(30,366)
EPA - NSPS TSD	2008	Connectors	1	9,991	incl. in total	25,622	515	4	2,061	2,061	negative	(23,561)
EPA - NSPS TSD	2008	Pressure Relief Devices	1	101,820	incl. in total	40,372	160	4	639	639	negative	(39,734)
EPA - NSPS TSD	2008	Open ended lines	1	12,280	incl. in total	26,200	693	4	2,772	2,772	negative	(23,428)
EPA - NSPS TSD	2008	Simple average	1	35,655	incl. in total	31,700	607	4	2,428	2,428	negative	(29,272)
EPA Lessons Learned[647]	2003	Gas processing plants	1	59,000 [b]	32,000 [c]	91,000	86,500 [d]	4	346,000	346,000	0.19	255,000
EPA Lessons Learned[648]	2003	Compressor stations	1	26,200		26,200	29,400	4	117,600	117,600	0.22	91,400
Methane to Markets	2009	Valves	1	130	??	??	2,895	4	11,580	11,580	likely +ve	likely +ve

[647] Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations, 2003
[648] Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Compressor Stations, 2003

Methane to Markets	2009	Connectors	1	10	??	??	3,482	4	13,928	13,928	likely +ve	likely +ve
Methane to Markets	2009	Open ended lines	1	60	??	??	2,320	4	9,280	9,280	likely +ve	likely +ve
Methane to Markets	2009	Simple average	1	67			2,899	4	11,596	11,596	likely +ve	likely +ve
Canadian experience	2005	Average	??								+ve	+ve

[a] Average of values from Tables 8-14, 8-15 and 8-17. Table 8-16 data was not included as that was only incremental cost data

[b] Average of $39,000 and $78,000 for repairs annually

[c] Average of $14,000 and $50,000 for leak screening and measurement annually

[d] Average of 45,000 and 128,000 Mcf/year per gas plant

In its NSPS TSD,[649] EPA included comprehensive calculations for the capital and operational cost of conducting leak detection and repair at existing gas processing plants. EPA reports that the annualized cost (including capital) for detecting and repairing leaks, by component, is between $20,000 and $40,000 on average. The savings of natural gas from these repairs is on the order of $1,000 - $4,000. As a result, EPA estimates that leak detection and repair incurs an annual operating loss and accordingly the investments do not pay back.

This is in sharp contrast with EPA Lessons Learned documents for both gas processing plants[650] and compressor stations.[651] In these examples, cost of repairs were between $25,000 and $60,000 per year per facility. For gas processing plants, leak screening and monitoring cost about $32,000 annually per plant. At both gas processing plants and compressor stations, the investments were profitable generating as much as $250,000 in annualized profit per facility, with payback periods of just a few months.

The NSPS TSD estimates are also very different from a 2009 Methane to Markets presentation showing that leak repair can be highly profitable.[652] Given the large differences between EPA and the Methane to Markets capital cost data, it is likely that the cost estimates are not like-for-like. For example, the latter did not include operational and labor costs, and it may have excluded broader system costs. The Methane to Markets presentation also estimates much larger average natural gas savings from discrete repairs, however, which would make detection and repair much more profitable than EPA predicts even when the additional costs are considered.

Additionally, Canadian experience with control of fugitive emissions at oil and gas facilities shows that: most methane leaks are from components in gas service; older facilities have the highest leak rates; about 75 to 85 percent of leaks are economic to repair; and the top 10 leaks at a facility generally contribute more than 80 percent of the emissions.[653]

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[649] EPA NSPS TSD, pages 8-23 – 8-30, mainly Tables 8-14 – 8-17.

[650] *Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations*, 2003, attached hereto as Exhibit 213.

[651] *Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Compressor Stations*, 2003, attached hereto as Exhibit 214.

[652] Methane to Markets, *Reducing Methane Emissions Through Directed Inspection and Maintenance (DI&M)*, Oil & Gas Subcommittee Technology Transfer Workshop, 2009, attached hereto as Exhibit 215. The Methane to Markets Partnership was a collaborative effort among 14 countries to address issues surrounding climate change, methane, and clean energy; the Global Methane initiative, formed by 37 governments and the European Commission in October 2010, builds on the Partnership's work.

[653] Picard, D. (Clearstone Engineering Ltd.), *Cost Effective Opportunities to Reduce Methane Emissions and Losses,* 2005, attached hereto as Exhibit 216.

3. Qualitative considerations of the costs of control technologies

As is apparent from the quantitative analysis presented above, EPA's cost estimates for many of the control technologies are conservative by our assessment, and so underestimate the reasonableness of the cost of control EPA's proposal would require.

We anticipate that some industry commenters may nonetheless contend that these costs must be higher than EPA, or we, have calculated, since those calculations show that some of these measures *save operators money,* yet they have not been universally adopted by operators.

Industry's failure to voluntarily adopt all of EPA's proposed controls does not indicate that the cost of control is not reasonable, or that the control in question is not correctly included as BSER. As explained by the American Petroleum Institute (API), these projects would need to meet internal hurdle rates and compete with core business projects for available capital.[654] Thus, companies may forego even profitable projects in favor of, for instance, new well construction, in the absence of federal regulation requiring them to take action.

For example, if a company has a hurdle rate of 30 percent for making investments, then the control technology would need to be quite profitable to meet this threshold. But this is not the standard for BSER purposes: instead, EPA is only to consider whether costs are truly exorbitant on an industry-wide basis. Therefore, there would be a very large number of projects, even within the Natural Gas STAR partner-companies, that would pose reasonable costs – indeed, in some cases, negative costs -- even while not meeting the likely high hurdle rates for voluntary implementation.

Market failures, in particular "principal agent" problems, can also prevent an industry from undertaking cost-effective measures. Structures of firms may not incentivize managers to undertake measures. Managers may also be quite excessively risk-averse, or simply excessively resistant to new technologies. Finally, managers may lack the necessary information to undertake cost-effective measures.

Moreover, the opinion of experts within the natural gas industry[655] demonstrates that a large number of natural gas companies, especially small to midsize ones, have yet to

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[654] American Petroleum Institute (API), and the International Petroleum Industry Environmental Conservation Association (IPIECA), *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects*, prepared by URS Corporation, March 2007, attached hereto as Exhibit 217, concludes at p. 18 "*Companies and investors operate under capital constrains and the estimated financial returns of such GHG reduction projects may not justify diverting capital from other higher return or more strategic initiatives.*"

[655] Public discussions in June 2011 convened by the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board on natural gas operations, with C-level executives from Chesapeake, Schlumberger, Anadarko, Chevron, ExxonMobil etc.; independent natural gas industry consultants.

update their outmoded practices and embrace a culture of efficiency and corporate responsibility. We therefore consider that significant opportunity to reduce methane emissions exists, especially from small to midsize operations.

Furthermore, the Natural Gas STAR program has about 130 partner companies,[656] with the number of companies in the various stages of natural gas operations being approximately: 30 in production; 10-15 in processing; 35 in transmission; and 55 in distribution. But the number of companies in the US in the various stages of natural gas operations far exceeds this number and is approximately: 6000 in production, 120 in processing; 250 in transmission and storage; 1200 in distribution (and 260 in marketing).[657] While there may be numerous overlaps due to companies operating in multiple stages, even if the total number of unique companies was only 1,500, this figure would still be more than ten times the number of companies participating in Natural Gas STAR. In other words, the number of Natural Gas STAR partner companies is lower than even 10% of the total number of companies. While some number of the remaining 90+% of companies may be smaller operators, they nonetheless would represent a sizeable fraction of natural gas operations. It is quite likely that these companies have not engaged significantly in VOC/methane control activities. As such, we consider that there may be a number of VOC/methane control opportunities, ranging from merely reasonable cost to highly profitable, that remain untapped.

Finally, the general phenomenon of regulation leading to increased productivity within affected firms has been observed in various sectors[658] and is consistent with economic theory.[659]

C. EPA Underestimated Savings Due to Natural Gas Capture Under its Proposal

As noted above, in addition to analyzing costs of implementing the technologies and any operational savings, EPA assessed the additional revenue from natural gas that was not emitted. Regulated entities will directly benefit from this additional revenue, as it will offset the cost of installing controls. As such, these benefits plainly affect "the cost of achieving such reduction" of emissions,[660] and so can and must be included in EPA's cost of control analysis.

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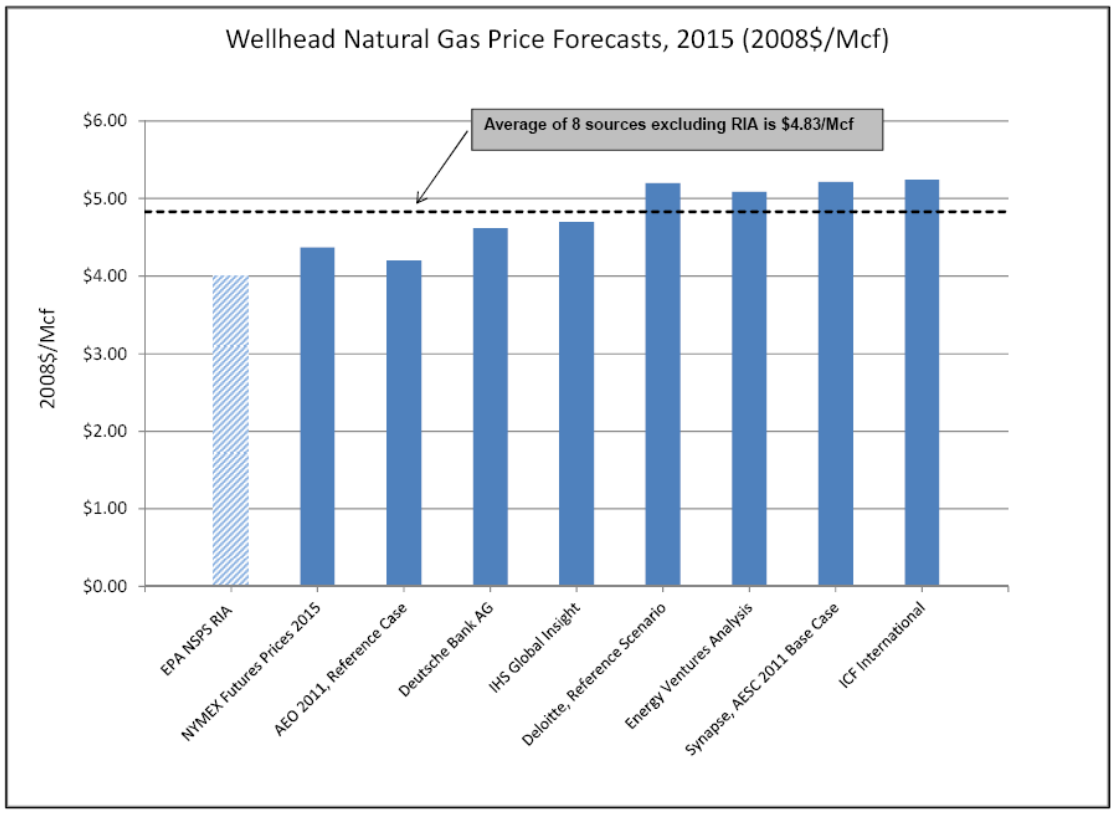
[656] EPA Natural Gas STAR: http://www.epa.gov/gasstar/documents/partnerlist.pdf
[657] http://www.naturalgas.org/business/industry.asp#industry; http://www.gpaglobal.org/membership/companies/
[658] Porter, M.E. (1990), *The Competitive Advantage of Nations*, Free Press, New York.
[659] Mohr, R.D. (2002), "Technical Change, External Economies, and the Porter Hypothesis," *J. Environ. Econ. Manag.,* 43, 158-168, doi:10.1006/jeem.2000.1166; Ambec, S., and P. Barla (2002), "A theoretical foundation of the Porter hypothesis," *Econ. Lett*., 75 (2002) 355–360, attached hereto as Exhibit 218.
[660] 42 U.S.C. § 7411(a)(1).

EPA assumed a $4/Mcf price for natural gas in its revenue calculations. EPA used these calculations in both the RIA and in its BSER determinations themselves.[661] EPA's price assumption is lower than all other projections, including the Energy Information Administration's. EPA must update its calculations to reflect a realistic gas price, using the Energy Information Administration and offering sensitivity analyses for other prices.

According to projections by Synapse Energy Economics submitted as an attachment to these comments, $4/Mcf is a low estimate for future natural gas prices, although it is above current prices. Indeed, this price is lower than $4.22/Mcf price forecast by the Energy Information Administration (EIA). As it turns out, it is lower than *every* other credible natural gas price projection.[662] Synapse concluded that the future price of natural gas was projected to be around $4.8/Mcf in 2015. Notably, prices beyond 2015 are projected to be even higher. Figure 7 below, drawn from that report, shows that some estimates exceed $5/Mcf, and *all* estimates are above EPA's.

Figure 7



[661] *See, e.g.*, 76 Fed. Reg. at 52,758 (taking cost savings from natural gas capture into account in proposing green completions as BSER).

[662] Synapse used data from eight different sources to conduct its analyses, including from the Energy Information Administration, Deutsche Bank, Deloitte, ICF International and NYMEX.

If EPA used even the EIA projection, it would "double the estimate of net cost savings of the proposed NSPS," going from $45 million to $90 million in savings.[663] If EPA were to use the mean value of all of the above cost estimates, $4.84 Mcf, it would estimate net cost savings of $180 million.[664]

The costs of implementing VOC/methane control technologies are very unlikely to rise as much as 20 percent (which is the relative difference between $4.8/Mcf and $4/Mcf) by 2015. Therefore, based on the higher projected price of natural gas, the economics of the methane control opportunities would become far more favorable. Moreover, the higher natural gas prices rise – recent volatility has seen prices go as high as about $8/Mcf – the more profitable methane control options become.

Recognizing that all forecasts are somewhat subjective, it is clear that EPA's forecast – and its projected cost savings – are systematically low. EPA must, therefore, use the EIA value, at a minimum, and include higher possible wellhead values, as it estimates the savings from the rule to supports its standards-setting analysis. Failure to do so masks the real, and extraordinary, benefits of EPA's proposal.

D. EPA Must Include the Quantified Social Benefits of Methane Reduction, in Addition to Non-Climate related Health Benefits Resulting from Methane Reduction.

According to EPA, the proposed rules, if finalized, would reduce methane emissions by 3.4 million tons per year, resulting in a net annual reduction in total greenhouse gases of approximately 62 million metric tons of CO_2 equivalent (CO_2e).[665] This is a substantial emissions reduction: It is larger than the *total* CO_2e emissions of several industry sectors, and will produce correspondingly large benefits by reducing the powerful climate influence of methane.[666] Although the benefits of this reduction do not speak to the direct cost of the controls required by EPA's proposed standards, and hence are not part of the BSER analysis, they are vitally important to the larger cost/benefit analysis EPA offers in the RIA for the rule. EPA must value them accurately.

EPA tentatively offers quantified co-benefits of between $110 to $1,400 per short ton of methane reduced (depending on discount rate) – for a total of $373 million to more than $4.7 billion[667] - but citing "the uncertainty involved" in the methods it uses,

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[663] RIA at 3-19.
[664] Rick Hornby and Dr. Carl Swanson, Synapse Energy Economics, *Estimate of 2015 Natural Gas Wellhead Prices* at 3, attached hereto as Exhibit 220.
[665] 76 Fed. Reg. at 52,792.
[666] *See, e.g.*, EPA, Inventory of U.S. Greenhouse Gases and Sinks (1990-2009), April 2011 at Table ES-2 (noting, for instance, that the total emissions from iron and steel production in 2009 was just 41.9 million metric tons of CO_2).
[667] RIA at 4-32.

"chooses not to compare these co-benefit estimates to the costs of the rule for this proposal."[668]

This is a substantial omission, as it fails to account adequately for one of the most significant benefits of the rule. EPA must not wait to have "interagency accepted monetary values" for the social benefits from methane reduction,[669] before including monetized benefit figures in its RIA. Indeed, E.O. 12866 calls upon the agency to include "quantifiable measures (to the fullest extent that these can be usefully estimated),";[670] E.O. 13563 likewise directs EPA to use the "best available techniques to quantify anticipated present and future benefits and costs as accurately as possible."[671] Neither of these sources permits EPA to wait for interagency agreement before assessing monetized costs.

Because EPA currently has two supportable quantification methods available – direct assessment of the social cost of methane ("social cost of methane method" or "SCM method") and using methane's GWP to calculate CO_2e, then multiplying by the social cost of carbon ("GWP method") – it must use these tools to report a range of monetized benefits for the rule.

As the Ninth Circuit Court of Appeals explained in *Center for Biological Diversity v. NHTSA*, some uncertainty in estimation methodologies does not support declining to quantitatively value benefits associated with reducing climate change pollution at all.[672] Where, as here, "the record shows that there is a range of values [for these benefits], the value of carbon emissions reduction is certainly not zero."[673] Therefore, the agency is obligated to consider such a value, or range of values.[674] Since the agency has a strong quantitative foundation now in the form of two methodologies for estimating the social cost of methane, it should provide monetized benefits using both of these methodologies in its formal cost-benefit assessment (accompanied by an explanation of any limitations and/or uncertainties in each methodology, as necessary).

Finally, EPA must also consider the *non-climate related* health and public welfare benefits of methane reductions. These arise because methane is a significant precursor of surface-level ozone, which causes significant morbidity and mortality and damages crops.

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[668] 76 Fed. Reg. at 52,792-93.
[669] *See* RIA at 4-32
[670] 58 Fed. Reg ____ (October 4, 1993)
[671] (76 Fed. Reg. at 3821 (January 21, 2011)
[672] *See Center for Biological Diversity,* 538 F.3d 1172, 1200 (9th Cir. 2008) (citing Office of Management and Budget Circular A-4 as providing that "agencies are to monetize costs and benefits whenever possible."), attached hereto as Exhibit 221.
[673] *See id*
[674] *See id.* at 1203.

1. EPA has two available methods for monetizing climate benefits from methane reduction.

The Social Cost of Methane Method ("SCM Method"). In Marten and Newbold,[675] the authors directly calculate the social cost of methane using the methodology used by the Interagency Working Group on the Social Cost of Carbon, with some updates. This direct method would be the most straightforward, defensible, and consistent with earlier valuation efforts of greenhouse gases.[676] EPA provides no reason why it cannot do the same here. The agency rejects earlier analyses of the direct social cost of methane, dated from 1994 to 2006, on the basis that "[t]he assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the [integrated assessment models]."[677] However, EPA only cites Marten and Newbold as supporting why the GWP method explored in the RIA may be viewed as a yielding a lower bound for quantified methane benefits,[678] not any reason why EPA cannot use the SCM method. As Marten and Newbold's method is a valid and analytically supportable method, EPA must include figures calculated using their social cost of methane approach.

The GWP Method. The GWP Method consists of converting the methane emission reductions to CO_2-equivalent using methane's global warming potential, then multiplying the resulting CO_2e figure by the social cost of carbon ("SCC"). As noted by Marten and Newbold, this approximation of the climate benefits of methane reductions underestimates benefits at the higher discount rates considered by the interagency SCC group; in one case the underestimate is in excess of 30%.[679] They further note, however, that values of the benefit of methane reductions "estimated using GWPs and the [SCC] will typically have lower absolute errors than default estimates of zero."[680] In other words, using GWP and the SCC to calculate the value of methane emissions reductions is more accurate than not calculating the value of methane reductions, and implying that the value is zero, as EPA has done by failing to compare any value of

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[675] Marten, A. L., and Newbold, S. C. (2011), "Estimating the Social Cost of Non-CO2 GHG Emissions: Methane and Nitrous Oxide," EPA NCEE Working Paper # 11-01, available at http://yosemite.epa.gov/EE/epa/eed.nsf/WPNumber/2011-01, attached hereto as Exhibit 222.

[676] We note that not all damages from climate warming (or non-climate damages from methane) are accounted for in any calculation of the SCM because they are not included in the underlying models. However, that the models may pose some uncertainties due to their incompleteness does not mean that EPA can refuse to use them. *See Center for Biological Diversity*, 538 F.3d at 1201-02 (rejecting NHTSA's claim that it did not have to monetize benefits because the models were too uncertain). In addition, the Johnson Report provides comments on how to remedy some of these shortcomings.

[677] RIA at 4-33.

[678] *See id.* at 4-32 (Marten and Newbold "suggest" that the "'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases")

[679] *Id.* at 16. These underestimates can be seen by comparing the SCM, as calculated by Marten and Newbold, with the product of the SCC as they calculated it and a GWP.

[680] Marten and Newbold at 1.

reduced methane emission to the cost of mitigation measures. If EPA is unable to include a directly-calculated SCM in support of the final rule due to methodological problems with the SCM, it must (after identifying and explaining those problems) instead include an estimate of methane-related climate benefits calculated by multiplying SCC by GWP (with an updated GWP as described below).

We note that the flaws and uncertainties in these methods spring from their under-estimation of the true costs of climate change damages, as well as the inherent limitations of attempting to monetize impacts such as human suffering, loss of life, and loss of non-human species. [681] Thus, while they must be considered by definition under-estimates of the true social cost of greenhouse gases, this does not allow the EPA to ignore the existing values entirely, thereby further under-stating the benefits of greenhouse gas reductions.

2. EPA must adjust certain assumptions in the GWP method and the underlying SCC method.

We also attach a detailed discussion by NRDC chief economist Dr. Laurie Johnson of needed adjustments in the GWP method, if EPA uses this approach, as well as in the underlying SCC, regardless of whether EPA includes estimates using the SCM or GWP method (as both the SCM and GWP approaches rely on the methodology of the SCC). This analysis, which we incorporate by reference into these comments, yields several important additional recommendations for EPA's analysis[682]:

First, EPA must use the most recent Intergovernmental Panel on Climate Change (IPCC) GWP values for methane. EPA uses the lower GWP value from the years-old IPCC Second Assessment Report, rather than from the more recent Fourth Assessment Report, because values from the Second Assessment are used in "global GHG inventories" (*i.e.,* produced under the guidelines of the United Nations Framework Convention on Climate Change).[683] Those inventories are not relevant to EPA's goal here, which is to accurately estimate methane benefits, not to report to a "global GHG inventor[y]." That these inventories still use inaccurate conversion values is simply not a justification to undercount methane benefits here.

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[681] See, e.g., Ackerman, F, and E. Stanton. 2010. *The Social Cost of Carbon. A Report for the Economics for Equity and the Environment Network*. Available at http://www.e3network.org/papers/SocialCostOfCarbon_SEI_20100401.pdf, attached hereto as Exhibit 223; Ackerman, F. Cost-Benefit Analysis of Climate Change: Where it Goes Wrong, pp.61-81 in Economic Thought and U.S. Climate Change Policy (David. M. Driesen, ed.) MIT Press, 2010.
[682] These recommendations are drawn from pp. 3-4 of Dr. Johnson's report.
[683] 76 Fed. Reg. at 52,793.

Second, even the most recent IPCC GWP from the Fourth Assessment may somewhat undervalue methane's strength as a climate forcer. EPA must, at least, include a sensitivity analysis using the more recent estimate from Shindell et al. of 33.[684]

Third, EPA must provide range of benefits yielded from the various methods and assumptions (c.f. table 1 in Marten and Newbold), as well as a clear, tabular, demonstration of how it has calculated the monetized benefits.

Fourth, as the larger Interagency Working Group on the Social Cost of Carbon continues to improve its calculations, EPA must be sure that these improvements are captured in its analysis here (if they occur during the rulemaking).

3. EPA must also Take Non-Climate Benefits of Reducing Methane Emissions Into Account

Although EPA does not regulate methane as a VOC precursor of ozone,[685] methane is a hydrocarbon which chemically oxidizes in the atmosphere to drive ozone production. While this oxidation is too slow for regional methane controls to substantially reduce ozone levels in that same region, anthropogenic methane contributes significantly to background levels of ground-level ozone around the world. Numerous modeling studies have predicted that reducing methane emissions can significantly reduce surface ozone.[686]

For example, West *et al.* (2006) report that reducing global anthropogenic methane emissions by about 20% would reduce the global average daily 8-hr ozone maximum by over 1 part per billion by volume (ppbv), "in agreement with other models [from other research groups]."[687] The reduction of ozone resulting from methane emissions abatement may be greater in densely populated urban areas, where other pollutants

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[684] D.T. Shindell, G. Faluvegi, D.M. Koch, G.A. Schmidt, N. Unger, S.E. Bauer (2009) "Improved Attribution of Climate Forcing to Emissions," *Science* 326 716-718, attached hereto as Exhibit 224.

[685] 40 C.F.R. §51.100(s).

[686] Fiore, A.M., J.J. West, L.W. Horowitz, V. Naik, and M.D. Schwarzkopf (2008) "Characterizing the tropospheric ozone response to methane emission controls and the benefits to climate and air quality," *J. Geophys. Res*., 113, D08307, doi:10.1029/2007JD009162, attached hereto as Exhibit 225.; Nolte, C.G., A.B. Gilliland, C. Hogrefe, and L.J. Mickley (2008) "Linking global to regional models to assess future climate impacts on surface ozone levels in the United States," *J. Geophys*. *Res*., 113, D14307, doi:10.1029/2007JD008497, attached hereto as Exhibit 226; Dentener, F., D. Stevenson, J. Cofala, R. Mechler, M. Amann, P. Bergamaschi, F. Raes, and R. Derwent, (2005) "The impact of air pollutant and methane emission controls on tropospheric ozone and radiative forcing: CTM calculations for the period 1990-2030," *Atmos. Chem. Phys*., 5, 1731-1755. Open online access: www.atmos-chem-phys.org/acp/5/1731/, attached hereto as Exhibit 227; Shindell, D.T., G. Faluvegi, N. Bell, and G.A. Schmidt (2005) "An emissions-based view of climate forcing by methane and tropospheric ozone," *Geophys. Res. Lett*., 32, L04803, doi:10.1029/2004GL021900, attached hereto as Exhibit 228.

[687] West, J.J., A.M. Fiore, L.W. Horowitz, and D.L. Mauzerall (2006) "Global health benefits of mitigating ozone pollution with methane emission controls," *Proc. Natl. Acad. Sciences* (USA) 103, 3988-3993, www.pnas.org/cgi/doi/10.1073/pnas.0600201103 at 3989, attached hereto as Exhibit 229

that catalyze oxidation of methane (e.g. NO_x) are more prevalent. This means that methane reductions will be most effective in reducing ozone in regions which are not in attainment, or are close to non-attainment, for ambient air quality standards for ozone, and where the negative affects of ozone are most acute.

In addition, Wild *et al.* analyzed projections of future emissions for the next several decades and how those emissions will affect surface ozone.[688] Their analysis predicts that global methane emissions will be the most important determinant of whether surface ozone in North America drops over the coming decades, or remains about constant.[689] If ozone remains near present levels, many areas will continue to struggle with attainment of the ambient air quality standard, and as a result public health and welfare will suffer. Their study shows "the increasing importance of limiting atmospheric methane growth as emissions of other precursors are controlled."[690]

Ground-level ozone has significant and well-documented negative impacts on public health and welfare. Some studies have documented how reductions in ground-level ozone resulting from methane emissions reductions in particular will benefit public health and welfare. A global 20% reduction in anthropogenic methane emissions would prevent 14,100 – 40,100 premature deaths in the northern hemisphere.[691]

Using a global value of a statistical life (VSL) of $1 million (substantially lower than the value used by EPA, currently $7.4 million (in 2006 dollars)[692]), West *et al.* calculate a monetized benefit from avoided mortality due to methane reductions of $240 per metric ton (range of $140 - $450 per metric ton).[693]

Ground-level ozone also significantly reduces yields of a wide variety of crops. A recent study finds that in 2000, ozone damage reduced global yields 3.9-15% for wheat, 8.5-14% for soybeans, and 2.2-5.5% for corn, with total costs for these three crops of $11 billion to $18 billion and costs within the US alone over $3 billion (all in year 2000 dollars).[694] Due to the growth in the emissions of ozone precursors in coming years, these crop losses are likely to increase. In 2030, ozone is predicted to reduce global yields 4-26% for wheat, 9.5-19% for soybeans, and 2.5-8.7% for corn, with total costs for

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[688] Wild, O., *et al,* (2011) "Modelling future changes in surface ozone: a parameterized approach," *Atmos. Chem. Phys. Discuss.*, 11, 27547–27590. Open online access: www.atmos-chem-phys-discuss.net/11/27547/2011/, attached hereto as Exhibit 230.
[689] Wild *et al.* figures 8 – 10, at 27,586 – 27,588.
[690] Wild *et al.* at 27,549.
[691] Anenberg, S.C., *et al.* (2009) "Intercontinental impacts of ozone pollution on human mortality," *Environ. Sci. & Technol.*, 43, 6482-6487, doi: 10.1021/es900518z, attached hereto as Exhibit 231
[692] http://yosemite.epa.gov/ee/epa/eed.nsf/pages/MortalityRiskValuation.html, attached hereto as Exhibit 232
[693] West *et al.* at 3991.
[694] Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 1. Year 2000 crop production losses and economic damage," *Atmos. Env.*, 45, 2284-2296, attached hereto as Exhibit 233

these three crops (2000 dollars) of $12 billion to $35 billion.[695] Another recent study included damage to rice (3-4% reduction in yield for year 2000) and finds even higher total costs for year 2000 ($14 billion to $26 billion).[696] Many other crops are damaged by ozone, so these estimates only capture a portion of the economic damage to crops from ground-level ozone. The value of avoiding a portion of these damages by reducing methane emissions must be considered in valuation of methane reductions.

Avnery *et al*.[697] report work underway to examine the benefits to crop yields from methane mitigation. This study, which will provide an estimate of the value of increased crop yields resulting from avoided ozone damages resulting from methane emission reductions, is currently under peer-review for publication in a scientific journal. We will submit this study as soon as it has been accepted for publication, so that EPA may consider it in order to provide a more accurate valuation of methane reductions.

Damages to human health and crops from ozone produced by methane emissions are independent of damages to human health and welfare resulting from the temperature increases and other negative consequences of climate change due to methane emissions.[698] Thus, a full accounting of benefits from methane reductions must include the sum of the climate-related benefits discussed above and the ozone-related health and crop yield benefits.

VIII. INDUSTRY GROWTH AND RIGOROUS CLEAN AIR REGULATIONS CAN GO HAND IN HAND

Despite the clear economic benefits of EPA's rules, we expect some commenters to argue that the rules will restrain the industry's growth. On the contrary, as we demonstrate below, air quality standards are compatible with successful natural gas expansion efforts.

A. Experience from Colorado and Wyoming, where industry has grown in the presence of strong standards.

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[695] Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 2. Year 2030 potential crop production losses and economic damage under two scenarios of O_3 pollution," *Atmos. Env.*, 45, 2297-2309, attached hereto as Exhibit 234.

[696] Van Dingenen, R, F.J. Dentener, F. Raes, M.C. Krol, L. Emberson, and J. Cofala, (2009) "The global impact of ozone on agricultural crop yields under current and future air quality legislation," *Atmos. Env.*, 43, 604-618, attached hereto as Exhibit 235.

[697] Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 1. Year 2000 crop production losses and economic damage," *Atmos. Env.*, 45, 2284-2296.

[698] These negative consequences from emissions of methane, independent of climate change, could be included in integrated assessment models used in the calculation of SCM. However, the model used by Marten and Newbold (see above) does not include these damages, so they must be added to the SCM. If the present benefit of methane reductions is calculated by multiplying the social cost of carbon by a global warming potential (see above) then damages independent of climate change inherently must be added, as that method cannot capture damages independent of climate.

EPA's proposed standards are similar to existing state-level regulations in Colorado and Wyoming, where compliance has not only been accomplished, but has been accompanied by rapid growth in the oil and natural gas industries. As John Corra, Director of the Wyoming Department of Environmental Quality, recently told a Department of Energy advisory panel on natural gas issues, thanks to several years of protective air emission limitations, the number of wells and gas production in active parts of WY have gone up, while air emissions have gone down.[699]

We have examined several metrics illustrating trends in the oil and natural gas sectors which show that both Colorado and Wyoming have experienced growth in those industries while meeting state air regulations, and in some cases, higher growth than both the U.S. overall and other states without such regulations. While this analysis does not quantify the impact of the regulations, (since we do not know what sort of growth these states might have seen in their absence), it does provide evidence that industry can thrive in the presence of these regulations.[700]

B. Regulatory Background in Colorado and Wyoming

Regulations to control emissions of VOCs and HAPs from oil and natural gas operations have been in place in Wyoming for over a decade and in Colorado since 2004. WY first introduced regulations for minor source crude oil, gas, and condensate production sources in October 1995. In 1997, the state lowered the applicability threshold for its minor source permitting program in response to "prospects of increased natural gas development in Southwest Wyoming and other parts of the state."[701] Wyoming promulgated presumptive best available control technology (BACT) guidance requiring oil and gas production facilities to control VOCs and HAPs associated with flashing losses from pressure vessels and storage tanks on January 6, 1999.[702] These requirements applied to new wells and recompletion or stimulation projects. WY subsequently strengthened its BACT requirements, first in August 2001 and again in 2004 and 2007, increasing the source types covered and stringency - with the most recent revision in March 2010. The current presumptive BACT guidance requires differing levels of control of emissions from well completions, pneumatic controllers and pumps, glycol

[699] See video of the July 13, 2011 meeting of the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board; Mr. Corra's presentation starts near the mid-way point. www.shalegas.energy.gov/media/Meeting_071311_Afternoon.html

[700] While this analysis does provide evidence that industry can thrive in the presence of regulation, it is important to understand its limitations. For example, there are a number of additional factors that may contribute to relative growth between states that have not been examined here. These factors include (but are not limited to) the relative potential between states for growth in terms of physical availability or access to resources, as well as general economic health at the local/regional level.

[701] http://deq.state.wy.us/aqd/Oil%20and%20Gas/052297.pdf, attached hereto as Exhibit 236

[702] http://deq.state.wy.us/aqd/Oil%20and%20Gas/oglette.pdf. Although we discuss the substance and effect of Wyoming's presumptive BACT regulations, we do not endorse the presumptive BACT concept as a matter of policy and law.

dehydrators, flash emissions from storage vessels, and separation vessels, depending on the location of the operations. More stringent requirements apply in areas of intense development, e.g. concentrated areas of development and in the immense Jonah and Pinedale Anticline development areas.

Colorado first introduced rules to limit emissions of VOCs and NO_x from oil and natural gas exploration and production facilities in ozone non-attainment (NA) areas in March 2004. Specifically, Regulation No. 7 required control of emissions from condensate operations with the potential for flash emissions, glycol dehydrators, gas processing plants and reciprocating internal combustion engines. In December 2006, Colorado revised Regulation No. 7 to require a greater level of control for condensate tanks located in the Denver metro ozone nonattainment area, and extended controls for dehydrators and condensate tanks statewide. In December 2008, Colorado added a requirement to control emissions from pneumatic devices located in ozone nonattainment and maintenance areas and extended the requirements to control NOx emissions from reciprocating internal combustion engines statewide. In 2009, the Colorado Oil and Gas Conservation Commission (COGCC) promulgated additional rules that have the effect of reducing emissions from glycol dehydrators and storage tanks located in the Piceance basin and well completions and pneumatic devices located statewide. These rules took effect in the spring of 2009.

C. Growth Trends

There are a number of possible metrics that can be used to measure the growth trends in the oil and natural gas industries in these states—we've focused on three data sets: operational rotary rig count, producing natural gas wells, and natural gas gross withdrawals. Data on rig count is from Baker Hughes and is available through 2010; data on gas wells and withdrawals is from the U.S. Department of Energy's Energy Information Administration (EIA) and is available through 2009.

D. Operational Rig Count

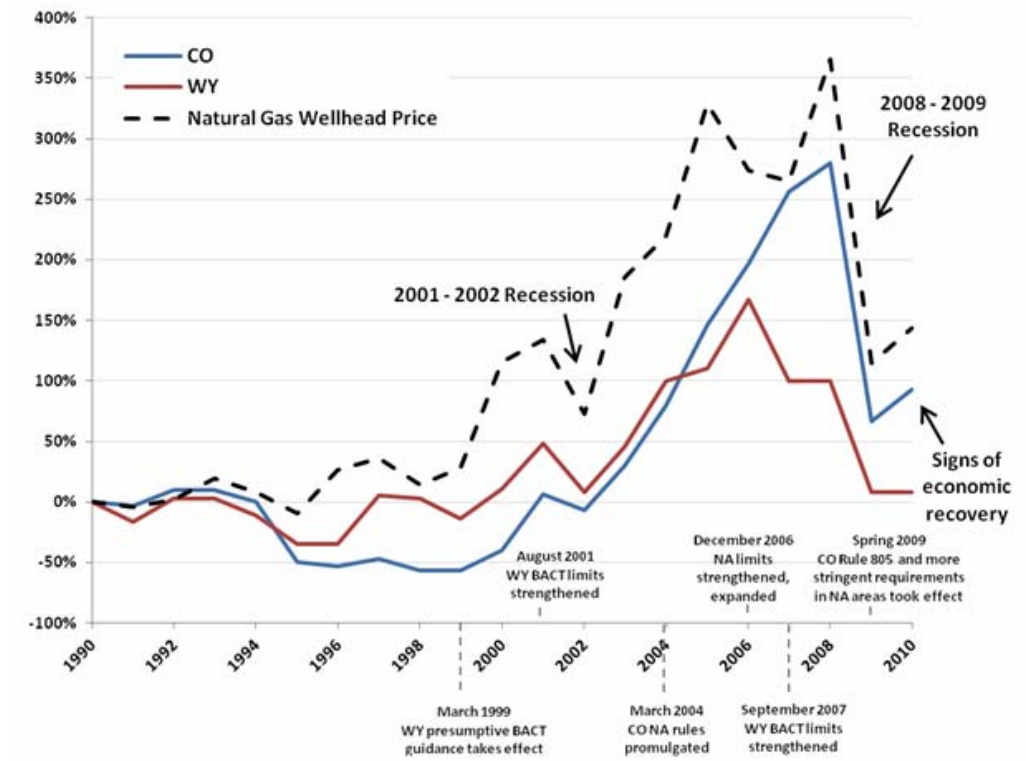
The data show that rig counts in Colorado and Wyoming have shown significant growth during the years of regulation, in some cases even higher than other states which do not have such regulations.[703] Colorado's growth has been particularly high, with an average annual growth rate over the 2000-2010 period of nearly 21%, higher than states such as Texas, Oklahoma, New Mexico, and Louisiana (states without similar air regulations) – this figure is also higher than the overall U.S. annual growth rate of about 12%.

[703] According to Headwater Economics, rig count serves as a good proxy for economic trends, and in particular, employment trends, since the majority of oil and gas industry jobs are associated with the drilling phase. Headwaters Economics, "Drilling Rig Activity Nears Twenty-Year High: Price and Technology Remain Key Drivers of Oil and Gas Drilling Activity", http://headwaterseconomics.org/wphw/wp-content/uploads/RigCounts.pdf (10 June 2011), attached hereto as Exhibit 237.

Colorado's rig count in 2010 was about triple what it was in the year 2000, while overall U.S. rig count did not quite double. The state's rig count growth is particularly high in the few years after 2004, exactly the year that the Regulation No. 7 rules went into effect.

While Wyoming's rig counts decrease following 2006, the data shows a generally increasing trend over the previous ten years during which regulations of some form were in place in the state, suggesting that rig counts are more responsive to factors other than regulation. Indeed, the trend in rig count in both Wyoming and Colorado closely follows that of natural gas prices, and shows notable decreases in the presence of a recession (e.g. 2001-2002, 2008-2009) – factors which appear to impact rig count more than the presence of regulation (see Figure 1). More recently, between 2009 and 2010, Wyoming's rig count leveled out, and Colorado showed signs of recovery, with a 16% increase in number of rigs.

Figure 8: Growth in Number of Rigs in WY and CO and Natural Gas Price Relative to 1990[704]



Sources: Based on rig count data from Baker Hughes[705] and natural gas wellhead price data from EIA.[706]

E. Permit Applications

Industry activity can also be represented through the number of permit applications for oil and natural gas development projects. In WY, for instance, a number of very large oil and gas projects are poised for approval on federal lands. The Bureau of Land Management (BLM) is currently preparing environmental impacts statements for the nearly 9,000-well Continental Divide Creston project, the 4,208 well Hiawatha project, the 1,861-well Moxa Arch project, the 3,500-well Normally Pressured Lance project, and the 838-well LaBarge Platform project.[707] All of these projects are moving forward while in the presence of WY rules regulating emissions from the oil and gas sector.

F. Producing Natural Gas Wells and Gross Natural Gas Withdrawals

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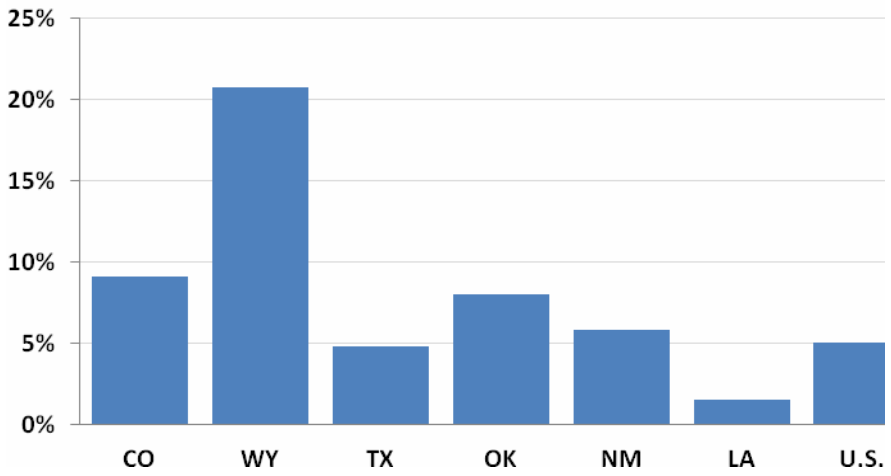
[704] 1990 was selected as the base year, as a year with all data available and early enough to be unaffected by the introduction of the first regulations on the oil and natural gas industries in Wyoming in 1995.
[705] http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm, attached hereto as Exhibit 238.
[706] http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm, attached hereto as Exhibit 239.
[707] http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA.Par.24843.File.dat/hot_sheet.pdf, attached hereto as Exhibit 240.

Colorado and Wyoming similarly show strong growth when considering other metrics: producing natural gas wells and gross natural gas withdrawals. In terms of the number of producing gas wells, they show the highest annual growth rates of the states examined with about 9% and 21% average annual growth rates respectively during the period 2000 to 2009, and higher than the average annual growth rate for the U.S. overall at 5% (see Figure 2).[708]

Figure 9: Average Annual Growth of Producing Natural Gas Wells in Selected States and the U.S., 2000-2009

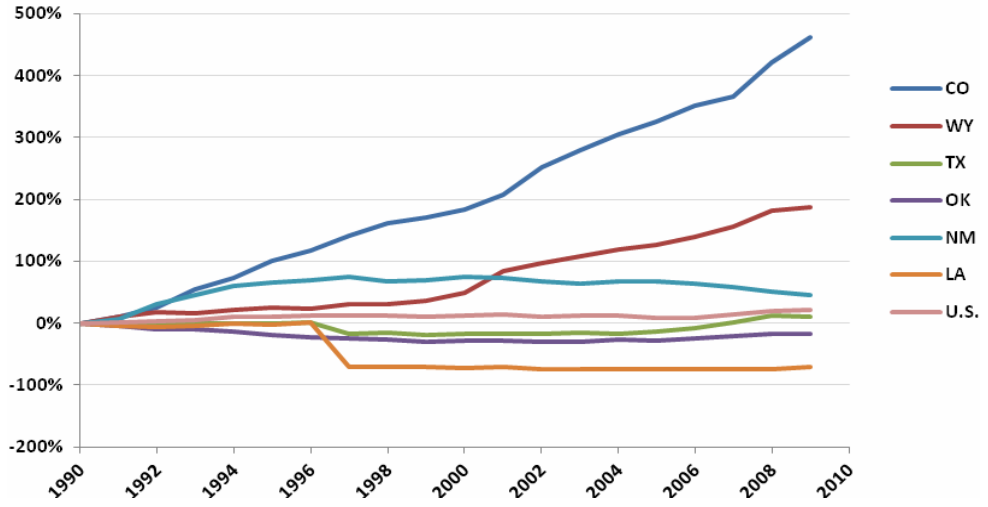


Sources: Based on data from EIA.[709]

Similarly, the two states also have the highest annual growth rates for gross withdrawals, both with average annual growth rates of about 8% over the same period, and higher than the overall U.S. growth rate of 1%.[710] Figure 3 shows that Colorado and Wyoming experienced more rapid growth in gas production than other selected states without similar regulations as well as the U.S. overall when examining the growth in withdrawals relative to 1990.

[708] Compared to 5%, 8%, 6%, and 2% for Texas, Oklahoma, New Mexico, Louisiana, (all states without similar state regulations), respectively.
[709] http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm, attached hereto as Exhibit 241.
[710] Compared to 3%, 2%, -2%, and -0.1% for Texas, Oklahoma, New Mexico, Louisiana (all states without similar state regulations), respectively.

Figure 10: Growth in Natural Gas Gross Withdrawals in Selected States and the U.S. Relative to 1990



Sources: Based on data from the EIA.[711]

The increase in the economic value of the oil and natural gas withdrawn in these states is also a strong indicator of the economic health of these states' oil and gas industries. For example, in 2010 the total value of taxable minerals in Wyoming was $15.5 billion, up 23% from 2009 and second only to the production value in 2008. The taxable value of oil production in Wyoming was $3.27 billion in 2010, up 34% from 2009, and the taxable value of natural gas production was $7.6 billion, up nearly 30% from 2009. [712]

Again, while we cannot quantify the impact of the regulations in Colorado and Wyoming, the bottom line is that CO and WY have shown considerable growth in these industries throughout the years of regulation—regulation comparable to the EPA's proposed federal rules. EPA's proposed rules therefore are not likely to impair the industry's growth; they will, instead, reduce the environmental impacts of that growth.

IX. EPA MUST PROMULGATE THE FINAL STANDARDS NO LATER THAN APRIL 3, 2012

Some oil and gas industry interest groups have asked EPA to delay implementation of the new source performance standards, in some instances, for up to one year.[713] We strongly oppose such requests. First they are contrary to the statute, which requires new sources on which construction is commenced after the date on which new standards are *proposed* to meet the standards once they begin operations.[714] Furthermore, EPA has already agreed to delay promulgation of the final rule to April 3,

[711] http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.
[712] http://taxappeals.state.wy.us/2011%20Abstract%20and%20Mill%20Levy%20Report.xls.
[713] For example, in a public announcement describing the rules as "reasonable" API requested an additional year to comply. SNL Daily Dose, Gas Edition, Sept. 28, 2011.
[714] 42 U.S.C. §§ 7411(a)(2), 7411(b)(1), 7411(e).

2012. This delay provides the industry with a full eight months from the time EPA first publicly announced the rules to final promulgation to ensure that new sources will meet the standards once they commence operations. We strongly oppose industry's claim that additional time is needed; indeed, additional time will prolong EPA's violation of its duty to review and revise the standards.

A. The Standards Can and Must Be Implemented Quickly, as a Matter of Law and Practice

As we have noted, standards to reduce air pollution from the thousands of emission points in the oil and gas sector are already long over-due. Under the statute, a review of the NSPS was required over a decade ago.[715] Similarly, a review of the NESHAPs for major sources must have occurred by 2007.[716] Due to EPA's failure to review and revise the current standards, the industry has operated under outdated and insufficient standards for far longer than Congress intended or mandated, at the expense of human health and environmental welfare. Expeditious promulgation of the final rules and compliance therewith is necessary to fulfill EPA's duty to protect human health and the environment.

Futhermore, the standards do not drive the adoption of new or novel control technologies. They largely codify best management practices already in use by many companies and required in California, Wyoming, and Colorado, among other places. Industry can readily implement these standards, even if EPA improves their rigor, as the statute requires and as we discuss above. Moreover, the standards largely apply only to new and modified sources on which construction has not yet commenced, and do not require the cessation of ongoing operations at existing sources. In fact, the only standard that applies to existing sources is the requirement that existing hydraulically fractured wells utilize reduced emission completions during re-completions.[717] Importantly, this requirement does not require an expensive or technically difficult retrofit, either, but rather simply requires that operators utilize the common best management practice of capturing natural gas, rather than venting or flaring it.

B. Even if Additional Delay Were Legally Permissible, It Would Be Unreasonable, as Industry Experience and State Regulation Near-Term Show Compliance Is Possible

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[715] 42 U.S.C. § 7411(b)(1)(B) (requiring EPA to "review and, if appropriate, revise" NSPS "at least every 8 years."). EPA promulgated the existing NSPS for the Crude Oil and Natural Gas Source Category in 1985: "Equipment Leaks of VOCs From Onshore Natural Gas Processing Plants", 50 Fed. Reg. 26122 (June 24, 1985), codified at 40 C.F.R. § 60.630; "Onshore Natural Gas Processing SO_2 Emissions", 50 Fed. Reg. 40158, 40 C.F.R. §60.640 (1985).

[716] 42 U.S.C. § 7412(d)(6) (requiring EPA "review, and revise as necessary" NESHAPs "no less often than every 8 years,"). EPA promulgated the existing NESHAPs for major sources in the Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories in 1999: "National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage", 64 Fed. Reg. 32610 (June 17, 1999), attached hereto as Exhibit 242.

[717] 76 Fed. Reg. at 52,799-800 (Proposed 40 C.F.R. § 60.5375).

The proposal codifies best management practices and technologies already in use by numerous companies.[718] These requirements are hardly technology forcing, or even novel, and must have come as no surprise to the regulated community—many of whom tout the proposed equipment and work practice standards as models of efficiency and savings. For example, Devon Energy, an operator in the Barnett Shale, reported saving 15.9 Bcf of gas between 1990 and 2007 from its use of reduced emission completions.[719] Devon also reported a $22 million increase in net gas-sale value between 2004 and 2007 due to implementing reduced emission completions.[720] Similarly, as noted at p. XX of these comments, numerous companies including BP, QEP Resources Inc., Shell Upstream Americas, Ultra Petroleum, Devon Energy, and EnCana have replaced high with low or no-bleed pneumatic devices and have realized considerable natural gas and monetary savings.

Colorado and Wyoming have adopted similar rules to those proposed by EPA. Colorado's most recent set of performance standard regulations provided industry five months to comply.

Colorado provided owners and operators of affected oil and gas facilities five months to comply with the state's most recent and comprehensive set of regulations promulgated by the Colorado Oil and Gas Conservation Commission ("COGCC"). These rules, which were adopted on Dec. 11, 2008 by the COGCC, took effect for owners or operators on state lands within four months (by April 1, 2009) and within five months for owners and operators operating on federal lands (May 1, 2009).[721] Like the NSPS, these rules required the use of low or no-bleed pneumatics at exploration and production sites, reduced emission completions statewide and 95% control of VOC emissions from condensate and crude oil storage tanks with the potential to emit ("PTE") 5 tons per year of VOCs located near public places in the Piceance basin.[722]

Colorado's Department of Public Health and Environment ("CDPHE") provided owners and operators of oil and gas facilities used in exploration and production activities less than five months to comply with its most recent rules to limit VOC emissions from oil and gas sources. The CDPHE finalized rules to limit emissions of ozone precursors in December 12, 2008. The rules require owners and operators of *existing* high-bleed pneumatic devices to replace them with low-bleed devices within five months, by May 1, 2009. Owners and operators of new and modified tanks were given until February 1, 2009 to comply with system-wide percentage reduction requirements and all tanks

[718] See e.g. infra pps xxx (discussion of EPA's consideration of costs).
[719] The American Oil & Gas Reporter, "Reducing Emissions Can Boost Profits", July 2007, http://www.epa.gov/gasstar/documents/aogr_2007.pdf, attached hereto as Exhibit 243.
[720] *Id*.
[721] COGCC Final Rules, Rule 805(b)(2).
[722] *Id*.

associated with new, re-completed or otherwise stimulated wells needed to control VOC emissions by 95% during the first 90 days of production.[723]

As Table 11 shows, Wyoming has required compliance with its presumptive BACT guidance upon the date of final revision or shortly thereafter. We note that we discuss Wyoming's presumptive BACT guidance solely to show what standards are possible, and what compliance times are reasonable. We do not endorse "presumptive BACT" as a legal matter.

Table 11

BACT REVISION	CONTENT	DATE PASSED	EFFECTIVE DATE
1998 revision	Established presumptive BACT requirements for storage tanks and pressure vessels with PTE 40 TPY VOC or more flash emissions	November 20, 1998	March 1, 1999
Chapter 6, Section 2 Permitting Guidance, Revision[724]	Lowered presumptive BACT requirements for storage tanks and pressure vessels to PTE 40 TPY VOC flash emissions and glycol dehydrators with PTE 15 TPY VOCs or 7 TPY total HAP	August 2001	N/A[725]
Jonah and Pinedale Anticline Gas	Lowered emission threshold for	July 28, 2004	Immediately

[723] CO Reg. 7, XII.D.1.
[724] Wyoming DEQ, Air Quality Division, Chapter 6, Section 2 Permitting Guidance, Revision http://deq.state.wy.us/aqd/Oil%20and%20Gas/GUIDANCE2001.pdf (August 2001), attached hereto as Exhibit 244.
[725] Wyoming did not publish an effective date on this guidance and conversations with Wyoming DEQ personnel have not been able to confirm a specific date.

Fields, Addition to Oil and Gas Production Facility Emission Controls and Permitting Requirements[726]	controls of flash emissions to 30 TPY, required quicker installation of flash emission controls and lowered emission threshold for controls on glycol dehydrators to 5 TPY total HAPs.		
Chapter 6, Section 2 Permitting Guidance, Revision[727]	Extended 5 TPY HAP applicability to sources located statewide; lowered applicability threshold for flash emissions to 20 TPY VOCs. Tightened Jonah and Pinedale Anticline requirements.	August 2007	September 1, 2007
Chapter 6, Section 2 Permitting Guidance, Revision[728]	Broadened scope of requirements to apply to greater number of sources and developed tiered	March 2010	August 1, 2010

[726] Wyoming DEQ, Air Quality Division, Revision Jonah and Pinedale Anticline Gas Fields, Addition to Oil and Gas Production Facility Emission Controls and Permitting Requirements, July 28, 2004, http://deq.state.wy.us/aqd/Oil%20and%20Gas/JONAH%20INFILL%20GUIDANCE%20FINAL%207-28-04.pdf., attached hereto as Exhibit 245.

[727] Wyoming DEQ, Air Quality Division, Chapter 6, Section 2 Permitting Guidance, Revision, http://deq.state.wy.us/aqd/Oil%20and%20Gas/AUGUST%202007%20O&G%20GUIDANCE%20-%20FINAL.pdf. attached hereto as Exhibit 246.

[728] Wyoming DEQ, Air Quality Division, Chapter 6, Section 2 Permitting Guidance, Revision, http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf. attached hereto as Exhibit 247.

	level of controls depending on location of source.		

With the exemption of compressors, all of the sources covered by EPA's proposal are currently subject to standards requiring similar levels of control by the states of Wyoming and Colorado. These states required compliance immediately, or in some instances, within months of final rule adoption even where retrofits of existing sources of air pollution were required to meet the standards. Accordingly, eight months is more than enough time for new sources in the oil and gas industry to meet with the new source performance standards. And again, this is particularly true because the standards require demonstrated practices in use by industry and do not require expensive retrofits of existing sources.

X. EPA MUST PROMULGATE AN ENFORCEABLE TIMELINE TO SWIFTLY ADDRESS REMAINING GAPS IN THE NSPS

Just as EPA must implement the standards it has proposed swiftly, it must commit to filling gaps in those standards quickly. As we have described above, the standards suffer from significant gaps, which are contrary to law. They (1) fail to control certain important facility types (such as liquids unloading from wells and heater-treaters); (2) they fail to control certain pollutants (such as PM, methane, and hydrogen sulfide); and (3) they fail to control existing sources. As we have explained, EPA must correct these failings.

That said, we understand that EPA must propose rules to address some of these failures before it can issue final rules, and that EPA must not (and must not) delay finalizing the rules it has proposed. This procedural necessity does not, however, allow EPA to simply avoid complying with its statutory obligations, and certainly does not allow EPA to put off fixing its flawed rulemaking until the next review cycle, eight years from now.

Instead, both to demonstrate that it will comply with the statute, and to provide industry with a clear regulatory calendar, EPA must set out an enforceable schedule, in the final rule issued in April, stating when it will propose, and then finalize, rules addressing each of the illegal gaps in the standards that we have identified.

EPA took precisely this step in its "Tailoring Rule," which sets out how EPA will implement the statutorily-required Prevention of Significant Deterioration program for greenhouse gases. Because EPA was unable to fully implement the program on the statutory timeline, it set out "an enforceable commitment to act" to fulfill its obligations by a date certain.[729] Without excusing its failures here, the agency must do the same,

[729] 75 Fed. Reg. 31,514 31,525 (June 3, 2010); *see also* 40 C.F.R. § 71.13 (codifying this commitment).

setting out a timeline for further action that is substantially shorter than the eight years of the NSPS review period. We ask that EPA complete the remaining rulemaking no later than 2013, which, though countenancing a long and illegal delay, will offer the agency some time to complete its work.

XI. CONCLUSION

Thank you for considering these comments. We look forward to working with EPA to strengthen the proposed rules so that the final rules will better protect communities across the country.

Sincerely,

Craig Segall
Nathan Matthews
Alison Vicks
Devorah Ancel
Joanne Spalding
Sierra Club[730]
50 F St NW, Eighth Floor
Washington, DC, 20009
(202) 548-4597
Craig.Segall@sierraclub.org

Kassie Siegel
Center for Biological Diversity
P.O. Box 549,
Joshua Tree, CA 92252
(760) 366-2232 x.302
ksiegel@biologicaldiversity.org

Joseph Otis Minott
Clean Air Council
135 South 19th Street, Ste 300
Philadelphia, PA 19103
215-567-4004

Praveen Amar
David Marshall
David McCabe
Darin Schroeder
Ann Weeks
Clean Air Task Force
18 Tremont Street, Suite 530,
Boston, MA 02108
(617) 624-0234
aweeks@catf.us

Meleah Geertsma
Vignesh Gowrishankar
Natural Resources Defense Council
1152 15th Street NW, Suite 300,
Washington, DC 20005
(202) 289-2382
mgeerstma@nrdc.org

Robin Cooley
Earthjustice
1400 Glenarm Place, #300
Denver, CO 80202
(303) 623-9466
rcooley@earthjustice.org

Bruce Baizel
Earthworks
1612 K St., NW, Suite 808
Washington, D.C., USA 20006
(202) 887-1872
bruce@earthworksaction.org

Ramon Alvarez
Susanne Brooks
Elizabeth Paranhos
Peter Zalzal
Environmental Defense Fund
2060 Broadway, Ste 300
Boulder, CO 80302
(303) 440-4901
elizabethparanhos@delonelaw.com

Vanessa Pesec
Network for Oil and Gas Accountability and Protection
Concord, Ohio
vpesec@roadrunner.com

Mike Eisenfeld
Dan Randolph
San Juan Citizens Alliance
1022 1/2 Main Ave.
Durango, CO 81301
970-259-3583
dan@sanjuancitizens.org

Jeremy Nichols
WildEarth Guardians
1536 Wynkoop, Suite 301 - Denver, CO 80202
303-573-4898 x 1303
jnichols@wildearthguardians.org

Bruce Pendery
Wyoming Outdoor Council
444 East 800 NorthLogan, UT 84321
(435) 752-2111
bruce@wyomingoutdoorcouncil.org

Julie Archer
West Virginia Surface Owners' Rights Organization
1500 Dixie Street
Charleston, WV 25311
(304) 346-5891
Julie@wvsoro.org

[730] With thanks to legal interns Paul Heberling and Jared Fish.

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 7

Joint Comments on the New York State RDSGEIS (January 11, 2012)

January 27, 2012

January 11, 2012

Attn: dSGEIS Comments
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Dear Sir or Madam:

Enclosed please find the comments of Catskill Mountainkeeper, Delaware Riverkeeper Network, Earthjustice, the Natural Resources Defense Council and Riverkeeper on the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Reservoirs, issued September 7, 2011, and draft regulations (Proposed Express Terms 6 NYCRR Parts 52, 190, 550-556, 560, 750.1, and 750.3), issued September 28, 2011.

Sincerely,

Wes Gillingham
Catskill Mountainkeeper

Maya van Rossum
the Delaware Riverkeeper, Delaware Riverkeeper Network

Deborah Goldberg
Earthjustice

Kate Sinding
Natural Resources Defense Council

Kate Hudson
Riverkeeper

THE **Louis Berger Group**, INC.
48 Wall Street, 16th Floor, New York, NY 10005
Tel 212 612 7900 Fax 212 363 4341
www.louisberger.com

Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Comments Summary Report: Expert Team Review of the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations

1.0 Introduction

The Louis Berger Group, Inc. (LBG) is pleased to submit this comment report on the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program and Proposed High Volume Hydraulic Fracturing (HVHF) Regulations to the Natural Resources Defense Council (NRDC) and its partner organizations, Earthjustice, Riverkeeper, Delaware Riverkeeper Network and Catskill Mountainkeeper. This comment report serves two primary purposes: 1) to provide general comments on the RDSGEIS and proposed regulations that are not limited to specific disciplines, and 2) to summarize the discipline-specific technical comments from NRDC's expert review team. The expert review team consisted of Harvey Consulting, LLC, Dr. Tom Myers, Dr. Glenn Miller, Dr. Ralph Seiler, Dr. Susan Christopherson, Meliora Design LLC, LBG, Kevin Heatley, Dr. Kim Knowlton, Dr. Gina Solomon, and Briana Mordick. The detailed technical comments from each author/organization are provided as attachments to this summary report and referenced as appropriate throughout.[1] Table 1 provides a complete list of technical comment attachments and summarizes the major topics areas addressed in each. Resumes for the members of the expert review team are provided in Attachment 12.

2.0 General Comments

2.1 RDSGEIS Fails to Address "Other Low-Permeability Shales"

The final scope and title of the RDSGEIS included other low-permeability shales, in addition to the Marcellus shale. The RDSGEIS makes it clear that development of other shales (including the Utica shale) is not only possible in the future, but is considered likely as evidenced by the inclusion of development of other shales in the Ecology & Environment. Inc. economic impact assessment.[2]

[1] All references cited and relied upon in the attached reports are hereby incorporated by reference into these comments. Hard and/or electronic copies of all references are available upon request.
[2] See the 11/23/2011 email from Steven Russo (NYSDEC) to Deborah Goldberg (Earthjustice) explaining the assumptions used in developing the scenarios for economic impact assessment include the development of "other shales."

Table 1
Technical Attachments to the Summary Comment Report

Attachment Number	Preparer	Topics Addressed
1	Harvey Consulting, LLC	Scope of SGEIS - Marcellus Shale Only Liquid Hydrocarbon Impacts Water Protection Threshold Well Casing Requirements Permanent Wellbore Plugging &Abandonment Requirements HVHF Design and Monitoring Hydraulic Fracture Treatment Additive Limitations Drilling Mud Composition and Disposal Reserve Pit Use and Drill Cutting Disposal HVHF Flowback Surface Impoundments at Drillsite HVHF Flowback Centralized Surface Impoundments Off-Drillsite Repeat HVHF Treatment Life Cycle Air Pollution Control and Monitoring Surface Setbacks from Sensitive Receptors Naturally Occurring Radioactive Materials Hydrogen Sulfide Chemical Tank, Waste Tank and Fuel Tank Containment Corrosion and Erosion Mitigation and Integrity Monitoring Programs Well Control and Emergency Response Capability Financial Assurance Amount Seismic Data Collection
2	Tom Myers, Ph. D.	Hydrogeology and Contaminant Transport Surface Water Hydrology Groundwater Quality Monitoring Setbacks from aquifers and public water supply wells Acid Rock Drainage
3	Glenn Miller, Ph.D.	Toxicology Hydraulic Fracturing Additives Naturally Occurring Radioactive Materials Contaminants in Flowback water and produced brines Wastewater Treatment issues
4	Ralph Seiler, Ph.D.	Radon in Marcellus Shale Natural Gas Naturally Occurring Radioactive Materials
5	Susan Christopherson, Ph.D.	Socioeconomic Impacts Pace and timing of natural gas development
6	Meliora Design, LLC	Water Quality Stormwater Erosion SPDES General Permit
7	The Louis Berger Group, Inc.	Noise and Vibration Visual impacts Land use Transportation Community character Cultural resources Aquatic Ecology
8[3]	Kevin Heatley, M.EPC LEED AP	Ecosystems and Wildlife
9	Kim Knowlton, DrPH	Climate Change and Public Health
10	Gina Solomon, M.D., M.P.H	Health Impact Assessment
11	Briana Mordick	Induced Seismicity

[3] Report prepared for and provided courtesy of the Delaware Riverkeeper Network.

The RDSGEIS adds some additional baseline geologic information on the Utica shale, but the environmental impacts specific to the Utica shale have not been addressed. For example, the Utica shale is almost twice as deep as the Marcellus shale, which means wells in the Utica shale will take longer to drill, would create more noise, would require more water, and would generate more waste and truck trips than wells in the Marcellus shale.

In addition to the incomplete study of deeper depth low permeability gas reservoirs, gas reservoirs at shallower depths than the Marcellus shale were not studied at all in the RDSGEIS. These shallower low-permeability shales pose development risks greater than those associated with the Marcellus shale because they are closer to protected water resources. Furthermore, the combined and/or concurrent exploitation of low-permeability shales at multiple depths may result in cumulative impacts not addressed in the RDSGEIS. The absence of the impact analyses of exploitation of shales at depths other than the Marcellus shale renders the RDSGEIS incomplete. NYSDEC should either evaluate additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the RDSGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

For additional detailed information supporting this comment, refer to Chapter 2 of the 2011 Harvey Consulting, LLC report (Attachment 1).

2.2 RDSGEIS and Regulations Fail to Protect the Environment from Non-HVHF Gas Development

While significant gaps remain as identified throughout these comments, the proposed regulatory framework for HVHF includes a number of improvements to NYSDEC's existing regulations to protect the environment from natural gas development. However, most of these improvements apply only to wells meeting the threshold to be classified as HVHF (defined as hydraulic fracturing using greater than 300,000 gallons of water).[4] NYSDEC is using a patchwork approach to regulating HVHF by adding new requirements on top of outdated requirements. A broader reform of the oil and gas development regulations is needed to address deficiencies in the existing regulations. This will ensure that best practice approaches are required for all natural gas wells in New York, including conventional wells and hydraulic fracturing using less than 300,000 gallons of water. Examples of reforms incorporated into the RDSGEIS and/or proposed regulations for HVHF that should apply to all wells include updated well casing requirements, emergency response plans and plans addressing the mitigation of noise, visual, transportation and ecological impacts.

2.3 RDSGEIS Fails to Address Indirect and Cumulative Impacts

The RDSGEIS fails to analyze important indirect and cumulative impacts as required by the State Environmental Quality Review Act (SEQRA). One of the most glaring examples of this is the

[4] The RDSGEIS arbitrarily increased the threshold for HVHF to 300,000 gal from 80,000 gal, as evaluated in the 1992 GEIS. There is no scientific justification given for the increase, and it effectively leaves all fracturing in the range 80,000-300,000 regulated by the existing rules without NYSDEC ever having conducted an environmental review showing that they are adequate for jobs that big.

RDSGEIS's failure to analyze the impacts of the pipelines and compressor stations that would be required to support the development of HVHF.

The RDSGEIS does not analyze any of the important impacts of pipelines and compressor stations (such as additional habitat fragmentation, noise and air pollutant emissions) based on flawed reasoning that such an analysis is not required because the pipelines would be reviewed under the Public Service Commission's Article VII process. The regulatory review process for pipelines is irrelevant—SEQRA requires state and local agencies to consider indirect "growth inducing" impacts. Pipelines and compressor stations are an indirect effect of the approval of HVHF. Without the approval of HVHF, there would be no reason to construct additional pipelines. Therefore, the pipelines/compressor stations and associated impacts cannot be separated from the environmental impact analysis of the HVHF regulatory program. The separate environmental review of the pipelines is, moreover, a form of segmentation, which is not permissible under SEQRA.[5] The additional natural gas pipelines and related infrastructure could also result in cumulative impacts when their impacts are combined with the impacts of HVHF that were analyzed in the RDSGEIS. The result of these deficiencies in the RDSGEIS is that the true impacts of the approval of HVHF have not been disclosed to the public and the requisite "hard look" under SEQRA has not been taken.

Similar to the treatment of pipeline infrastructure, the RDSGEIS also fails to analyze the cumulative impacts of numerous actions related to HVHF moving forward in New York, including the following:

- **Impacts from wastewater disposal and management**. The wastewater produced during the HVHF process is highly contaminated and could impact water resources if released into groundwater or surface water. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

- **Impacts from Centralized Flowback Impoundments.** The RDSGEIS fails to analyze the impacts of centralized flowback impoundments based on statements from industry that they will not be "routinely" proposed. While site-specific SEQRA review would be required for any centralized flowback impoundment, NYSDEC should have addressed the potential for significant adverse cumulative impacts (particular air quality and water resources) arising from centralized flowback impoundments in combination with the other impacts of HVHF discussed in the RDSGEIS.

- **Impacts from seismic data collection.** Seismic data collection has the potential to create

[5] See 6 § NYCRR (617.2(ag)): "Segmentation means the division of the environmental review of an action such that various activities or stages are addressed under this Part as though they were independent, unrelated activities, needing individual determinations of significance."

habitat fragmentation through the clearing of long linear corridors, among other impacts. Seismic data collection is a reasonably foreseeable part of the development process and should have been considered as an aspect of the cumulative effects assessment in the RDSGEIS.

- **Impacts from liquid petroleum.** The development of the Marcellus shale has the potential to result in wells the encounter liquid hydrocarbons. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be proposed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. None of these impacts were considered in the RDSGEIS.

- **Impacts from land use change**. The RDSGEIS contains some information about potential economic benefits, but does not examine how increase population and employment would change land use. Changes in land use would result in greater demands on the transportation system as well as ecological impacts from new residential and commercial development (above and beyond the direct impacts of the well pad sites themselves).

Fundamentally, the RDSGEIS analyzes only certain elements of HVHF and fails to analyze all elements of the process, both individually and collectively.

2.4 Unenforceable Mitigation under the HVHF Regulatory Framework

As noted throughout the detailed technical review comments, the RDSGEIS includes numerous mitigation commitments that are not enforceable because they are not included in the proposed regulations or supplemental permit conditions.

To provide a consistent regulatory framework for industry and to protect the environment, mitigation measures that would be applied across all HVHF operations should be incorporated into the proposed regulations. Mitigation measures that are site-specific should be incorporated into the supplemental permit conditions. Mitigation measures that are suggested in the RDSGEIS itself that are unenforceable (i.e., not codified through regulatory or other mechanisms) should be acknowledged as such and reduced efficacy of mitigation due to the lack of enforcement should be analyzed and disclosed.

2.5 Setbacks

As a general matter, the setback requirements stipulated by proposed HVHF regulations are inadequate to protect public health and environmental quality. Table 2 provides a summary of the setbacks proposed in the RDSGEIS and/or regulations and the recommended revisions to the setbacks based on the expert reviews conducted for NRDC.

For example, the minimum setback according to the HVHF regulatory framework for a residence is 100-feet. This is inadequate considering the potential for blowouts to eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. Other risks to residences and schools within close proximity to HVHF operations include noise levels that damage hearing and, exposure to hazardous gases, chemicals, fuels, and explosive charges.

The potential radius of impact for explosions, fire, and other industrial hazards should be considered in the RDSGEIS and proposed HVHF regulations. For example, Fort Worth Texas uses the International Fire Code as the basis for its minimum 600' setback from shale gas drilling operations. The figure below shows how the HVHF regulations setback distance requirements are significantly shorter and thus less protective than the requirements in other locations.

Comparison of NYS Setbacks from Homes and Public Buildings to Fort Worth, Texas Setbacks

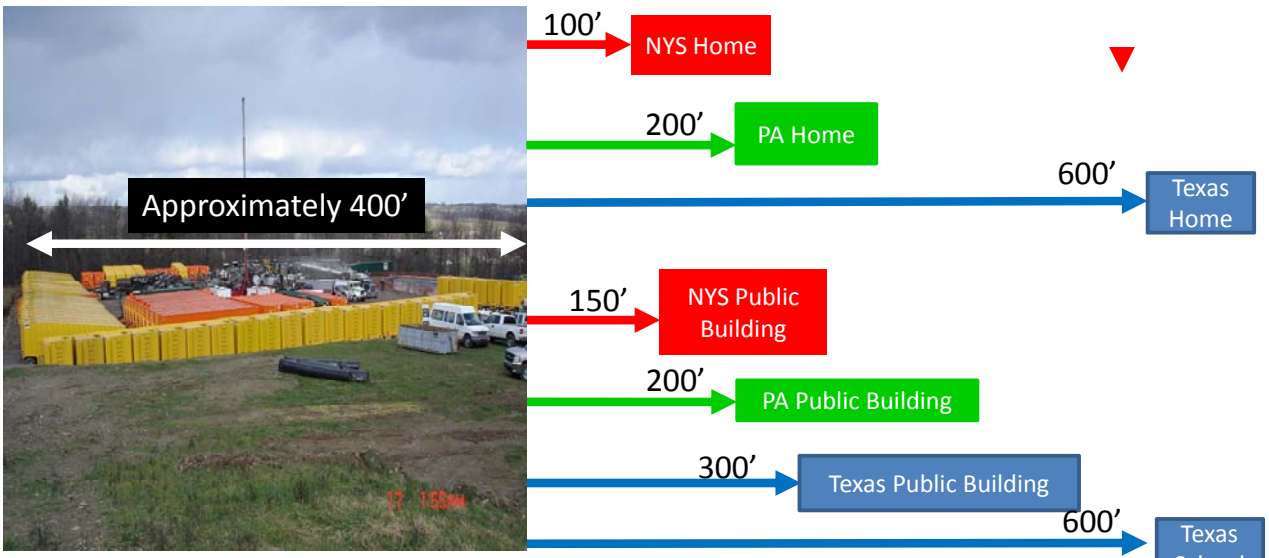

Photo 5.7 from SGEIS
Annotated by HCLLC
Distances shown by arrows drawn to scale

2.6 Insufficient Public Review of HVHF Permit Applications

The RDSGEIS fails to provide a clear and accessible process for public and local government access to site-specific HVHF activity information, while at the same time placing the burden on local government (and not the industry) to provide notice to NYSDEC that a HVHF activity may not be in compliance with local zoning or land use regulations (RDSGEIS pages 8-4 and 8-5). This essentially puts the regulatory burden on local government and at the same time fails to provide local government with access to the necessary information. The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public. NYSDEC should require public notice of the availability of HVHF permit applications locally through publication of a notice in a newspaper of general circulation and statewide through a centralized website. Permit applicants should be required to provide copies of their application to the affected municipality. The public should have immediate online access to all supporting documentation submitted with each permit application and the public review timeframe should be no less than 30 days. The regulatory framework must incorporate a mechanism for public comments on permit applications to be considered by NYSDEC before the decision to grant or reject a permit application is made.

Table 2
Summary of Setback Recommendations

	Minimum Setback under Existing/Proposed HVHF Regulatory Framework	Recommended Minimum Setback	Rationale/Notes
Residences	100 feet 6 NYCRR § 553.2	1,320 feet	Protects from noise, explosions, fire, and other industrial hazards.
Public Buildings (including schools)	150 feet 6 NYCRR § 553.2		
Primary Aquifers	500 feet 6 NYCRR § 560.4	4,000 feet	The 500 feet setback for primary aquifers should be increased to 4,000 feet (the same setback distance adopted in the RDSGEIS for Filtration Avoidance Determination watersheds), unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.
Principal Aquifers	500 feet in RDSGEIS (page 1-18) but not in the proposed regulations**	4,000 feet	The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.
Public Water Supplies	2,000 feet (6 NYCRR § 560.4)	4,000 feet	The setback for public water supplies should be the same as for principal aquifers (4,000 feet) and the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.
Private Drinking Water Wells	500 feet* (6 NYCRR § 560.4)	4,000 feet	Private and public wells should be protected to the same extent. NYSDEC should not allow the owner to waive the private well setback requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.
Stream, Storm Drain, Lake, or Pond	150 feet**	660 feet	The regulations currently contain conflicting and unclear requirements with respect to surface water resource setbacks. The regulations should be revised provide consistent setback requirements that are protective of water sources, including rivers, streams (perennial and intermittent), and lakes.
Filtration Avoidance Determination Watersheds	4,000 feet in RDSGEIS (page 7-56) but not in the proposed regulations	4,000 feet	Incorporate RDSGEIS setback commitment into regulations. In addition, the operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the FAD watershed.
Floodplains	Wellpads prohibited in the 100-year floodplain (6 NYCRR § 560.4)	Wellpads prohibited in the 500-year floodplain	For wells that might operate for 30 years, there is a 26% chance of a 100-year flood occurring during the period the well would be operated. Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.

*Setback can be waived by the landowner. The proposed regulations do not address setbacks for domestic use springs
** Setback could be waived based on site-specific analysis.

2.7 Impacts of Well Refracture Not Addressed

The assessments of environmental impacts in the RDSGEIS are all based on a single hydraulic fracturing treatment of each well. The RDSGEIS inappropriately relies on informal statements from industry that refracturing will be rare and does not quantify the number of HVHF treatments possible per well. The RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several-decade long lifecycle. The RDSGEIS should quantify how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. Additionally, the RDSGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts. Refer to Chapter 16 of the Harvey Consulting, LLC report (Attachment 1) for more information supporting this comment.

3.0 Summary of Technical Comments

3.1 Liquid Petroleum Impacts

The RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be needed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.

The RDSGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The RDSGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drill sites that may be required to develop oil resources identified by shale gas exploration and production activities.

The comments summarized in this section are covered in greater detail in Chapter 3 of the Harvey Consulting, LLC report (Attachment 1).

3.2 Well Casing Requirements

The comments summarized in this section are covered in greater detail in Chapters 5 through 8 of the Harvey Consulting, LLC report (Attachment 1).

3.2.1 Conductor Casing

Conductor casing is the first string of casing in a well and is installed to prevent the top of the well from caving in. The conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the proposed regulations and should

apply to all natural gas wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

3.2.2 Surface Casing

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well. Stray gas may impact groundwater and surface water from poor well construction practices. Properly constructed and operated gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion. Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania and other locations.

The RDSGEIS and proposed regulations include important improvements for surface casing that incorporate many of the comments provided by this working group in 2009. Notable improvements include requirements related to cement quality, casing quality, and installation techniques. Unfortunately, there are a number of inconsistencies between the permit conditions and the proposed regulations that create uncertainty about what will be required. The Harvey Consulting, LLC report provides recommendations for correcting these inconsistencies. Finally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.3 Intermediate Casing

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. The RDSGEIS and proposed regulations include important improvements for intermediate casing in comparison to the 2009 DSGEIS. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. However, the remaining area for improvement in the proposed regulations is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing, on which the proposed regulations are silent. There are also a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.4 Production Casing

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone or, alternatively, it is set just above the hydrocarbon zone. Production casing is used to isolate hydrocarbon zones and to contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier

that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The RDSGEIS and proposed regulations include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the proposed regulations is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and proposed regulations require production casing to be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. The proposed regulations also require the cement placement and bond be verified by well logging tools. These requirements are best practice. The Harvey Consulting, LLC report provides minor additional recommendations to improve consistency of the various requirements for production casing and highlights additional best practices that should be considered.

3.3 HVHF Design and Monitoring

Computer modeling is routinely used by industry to design hydraulic fracture treatments. During actual fracture stimulation treatments, data is collected to verify model accuracy, and the model is continually refined to improve its predictive capability. Data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability. HVHF modeling is an important way of helping to ensure fracture treatments do not extend outside the target formation. Fracture treatments that propagate outside the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport.

The RDSGEIS does not require well operators to develop or maintain a hydraulic fracture model. Instead, the RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned. Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. Instead, NYSDEC needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and the environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective; it is also good business because it optimizes gas production and reduces hydraulic fracture treatment cost. Best practices for HVHF design and monitoring should be included as a mitigation measure, and codified in regulations as a minimum standard. These best practices include utilizing hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone.

The comments summarized in this section are covered in greater detail in Chapter 10 of the Harvey Consulting, LLC report (Attachment 1).

3.4 Corrosion and Erosion Mitigation and Integrity Monitoring Programs

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide

(CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves. HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require that facilities be designed to resist corrosion (e.g., material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment. Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be evaluated and codified in regulations. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

The comments summarized in this section are covered in greater detail in Chapter 23 of the Harvey Consulting, LLC report (Attachment 1).

3.5 Well Control & Emergency Response Capability

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems. The addition of an Emergency Response Plan (ERP) requirement to the RDSGEIS is a substantial improvement over the 2009 DSGEIS, which failed to address this issue. However, it is recommended that NYSDEC include a review, approval, and audit processes to ensure that quality ERPs are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

The comments summarized in this section are covered in greater detail in Chapter 24 the Harvey Consulting, LLC report (Attachment 1).

3.6 Financial Assurance Amount

NYSDEC ignored comments submitted by this working group in 2009 requesting that the SGEIS examine financial assurance requirements to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination). Although changes in financial assurance amounts would require legislative action, the analysis of this issue is necessary to fully disclose the potential adverse environmental impacts that would result in the absence of adequate financial assurances. Moreover, such an analysis would be an appropriate way of bringing this need for legislation to the attention of elected officials as appropriate mitigation for identified significant adverse impacts.

The importance of reevaluating financial assurance requirements is heightened when the inadequacy of the existing requirements is considered. For wells between 2,500’ and 6,000’ in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000. For wells drilled more than 6,000’ deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based solely on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6). These requirements are

far less than those in other locations. Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well. Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS. In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas.

NYSDEC's financial assurance requirements should not narrowly focus on the costs of plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment. Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be evaluated and included in the proposed regulations.

The comments summarized in this section are covered in greater detail in Chapter 25 of the Harvey Consulting, LLC report (Attachment 1).

3.7 Hydrogeology and Contaminant Transport

The RDSGEIS dismisses the potential for groundwater contamination due to HVHF on the basis of faulty science and unsupported assumptions.

1. The characterization of the hydraulic fracturing process and effects in the RDSGEIS is technically incorrect, leading to important impacts being overlooked.

2. The RDSGEIS assumes that the geologic layers above the Marcellus shale will stop contamination of aquifers without providing sufficient information on these layers, and ignoring the potential for existing faults and fractures to expedite contaminant transport. It also ignores studies which show that hydraulic fracturing has fractured formations as much as 1500 feet above the target shale, thereby providing pathways through the rock which the RDSGEIS relies on for stopping contaminant transport.

3. The RDSGEIS impact analyses are incomplete from a spatial perspective. The analyses focus on *local* impacts and fails to address the *regional* impacts of HVHF on the characteristics of the shale and the environmental implications of these changes. Such changes include increased shale permeability to water flow, which increases the risk of aquifer contamination over time.

4. The RDSGEIS analyses are incomplete from a temporal perspective. The analyses do not address the potential long-term aquifer contamination impacts by focusing on a time period of few days, assuming contamination has not occurred in other locations that lack the monitoring that would be necessary to detect contamination, and not considering evidence of the potential vertical movement of fracking fluid to near-surface aquifers as discovered under comparable conditions elsewhere.

Detailed technical supporting information for the deficiencies noted above is provided in the report prepared by Dr. Tom Myers (Attachment 2). The Myers report also provides a number of important recommendations for:

1. Improving and expanding the characterization of the hydraulic fracturing process and impacts in the RDSGEIS; and
2. Implementing measures as part of the review of specific well site proposals to avoid significant adverse aquifer contamination impacts.

The measures should include the following:

1. Mapping groundwater gradients above the Marcellus shale using existing data.
2. Requiring seismic surveys to locate faults prior to drilling.
3. Implementation of a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport.

The groundwater monitoring at domestic wells proposed in the RDSGEIS is a scientifically improper method of monitoring the location of a contaminant plume because domestic wells are not designed for monitoring. Dedicated monitoring wells are necessary to prevent contamination of water wells by detecting contaminants before they reach the water wells.

3.8 Well Plugging and Abandonment

Wells that are not properly plugged can act as a preferential pathway for surface contaminants to impact groundwater resources. There are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned). As a result, there is a risk that improperly planned HVHF wells or fractures could intersect abandoned wells and contaminate groundwater. Key recommendations from Chapter 9 of the Harvey Consulting, LLC report (Attachment 1) related to well plugging and abandonment (P&A) include the following:

- The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

- The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

- The SGEIS requirements with respect to the plugging of improperly abandoned wells nearby proposed HVHF wells should be strengthened and incorporated in the proposed regulations.

3.9 Seismic Data Collection

Seismic surveys are used by industry to target hydrocarbon formations for exploration and appraisal drilling. Typically seismic surveys are conducted using vehicle-mounted vibrator plates that impact the ground or use explosive to create seismic waves which bounce off of subsurface rock strata and geologic formations. The reflected seismic waves are measured at various surface receivers. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight "cutlines" to run seismic equipment (up to 20'-50' wide). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection.

The RDSGEIS does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys. If 2D or 3D seismic surveys are planned, or are possible in the future, the proposed HVHF regulations should codify a permitting process for these activities and institute mitigating measures in the RDSGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas. In addition, the increased industrial activity (e.g., economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the RDSGEIS.

The comments summarized in this section are covered in greater detail in Chapter 26 of the Harvey Consulting, LLC report (Attachment 1).

3.10 Surface Water Hydrology

The RDSGEIS has addressed many of the deficiencies of the 2009 DSGEIS with respect to the treatment of hydrology issues. As discussed in the Myers report (Attachment 2), NYSDEC proposes to use the natural flow regime method (NFRM) for all regions by means of permit conditions. However, NYSDEC should verify the accuracy for the proposed methods for estimating passby flows at ungauged sites. Since NFRM is proposed to be applied everywhere (and not just in a specific case which would justify its use as a permit condition), it would be more appropriate for NYSDEC to include the use of the NFRM as a requirement in the regulations themselves. The following changes should be accounted for in the regulatory framework regarding the avoidance or reduction of potential impacts resulting from water withdrawal:

- NYSDEC should coordinate water withdrawals among operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.
- The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.
- Passby flows should be maintained with consideration of the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating

flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.

3.11 Stormwater, Sedimentation and Erosion

All of the comments summarized in this section are covered in greater detail in the Meliora Design, LLC report (Attachment 6).

3.11.1 Cumulative Water Quality Impacts of Land Disturbance Are Not Addressed

The RDSGEIS provides only a very brief generic discussion of the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). The RDSGEIS makes no attempt to evaluate the cumulative impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the original draft of the GEIS nearly twenty years ago, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts on water quality in the most general and generic manner, with little industry specific consideration, and no consideration of total or cumulative impacts. A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential to a full environmental impact analysis, and to any determinations by NYSDEC on the appropriate regulatory permitting requirements.

3.11.2 Stream Crossing Impacts Are Not Addressed

The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically not included in the Draft State Pollutant Discharge Elimination System (SPDES) General Permit. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current NYSDEC regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. NYSDEC should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed requirements to regulate and mitigate these impacts.

3.11.3 Mitigation and SPDES General Permit Do Not Consider Existing Water Quality

With the exception of watersheds that have received Filtration Avoidance Determinations, the RDSGEIS (and associated Draft SPDES HVHF General Permit) do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support the adequacy of the proposed setbacks to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep slopes), and the setbacks

discussed in the narrative of Chapter 7 are not clearly coordinated with EAF requirements in Appendices 4, 5, 6 and 10 and the Draft HVHF General Permit mapping and documentation requirements (and the Draft SPDES HVHF General Permit is presumably the regulatory mechanism for compliance). NYSDEC should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.

3.11.4 SPDES General Permit Flawed

The Draft SPDES General Permit for HVHF is essentially a compilation of the NYSDEC's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. It is not clear from the RDSGEIS's very limited discussion of land disturbance and surface water impacts that a general permit process is sufficient to protect water quality. It is also not clear that an industry that is not subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF. Finally, the general permit process does not provide a timeframe (or process) for public review, comment, and objection to any or all parts of proposed general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the NYSDEC and meeting minimum performance requirements. The SPDES HVHF General permit should provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site before general permit coverage is granted. The permit coverage timeline should be adjusted to provide for public comment and appeal.

3.12 Hazardous and Contaminated Materials Management

All of the comments summarized in this section are covered in greater detail in the Harvey Consulting, LLC report (Attachment 1) and the report of Dr. Glenn Miller (Attachment 3).

3.12.1 Disposal of Waste and Equipment Containing NORM

Naturally Occurring Radioactive Materials (NORM) can be brought to the surface in a number of ways during drilling, completion, and production operations:

- **Drilling**: Drill cuttings containing NORM are circulated to the surface.
- **Completion**: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- **Production**: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

The RDSGEIS fails to establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved relative to the 2009 DSGEIS in that it establishes radioactive limitations and testing in some cases, but testing is

still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g., for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

3.12.2 Drilling Mud Composition and Disposal

Drilling muds may contain mercury, metals, Naturally Occurring Radioactive Materials (NORM), oils and other contaminates. The NYSDEC appropriately removed the statement that "*drilling muds are not considered to be polluting fluids"* from the proposed regulations in response to this working group's 2009 comments. This positive change is commendable, but there are two problems related to the regulation of drilling muds that remain:

- The RDSGEIS states that the vertical portion of wells would be "typically" drilled using compressed air or freshwater mud as the drilling fluid. There is no regulatory restriction on industry using toxic additives in drilling mud, with corresponding increases in the risks of water resources contamination during drilling, transport and disposal. NYSDEC should stipulate in the regulations the mandatory use of compressed air or freshwater mud and prohibit the use oil-based muds, synthetic-based muds and the use of toxic additives.
- The proposed regulations do not provide criteria for acceptable drilling mud disposal plans to ensure safe handling and disposal. The proposed regulations should require specific best practices for drilling mud handling and disposal.

3.12.3 Reserve Pit Use and Drill Cuttings Disposal

The RDSGEIS acknowledges the numerous environmental advantages of a closed loop tank system to manage drilling fluids and cuttings rather than reserve pits, but fails to require a closed loop tank system in all circumstances. The closed loop tank system is only required for wells without an acceptable acid rock drainage mitigation plan for onsite disposal and for cuttings that need to be disposed at a landfill because they contain toxic additives. The proposed regulations should prohibit reserve pits and require a closed loop tank system. Reserve pits should only be allowed where the applicant demonstrates that the closed loop tank system would be technically infeasible. The proposed regulations also should include testing of the shale to determine the extent of potentially acid generating material included in the cutting.

The RDSGEIS states that onsite disposal of water-based muds is permissible, despite the fact that these muds may contain mercury, metals and other contaminates. These contaminated muds would be put in direct contact with soils and groundwater, resulting in the potential for significant adverse environmental impacts not addressed in the RDSGEIS. Some portions of the RDSGEIS and proposed regulations vaguely reference a requirement for consultation with the NYSDEC Division of Materials Management prior to disposal of cuttings from water-based mud drilling, but this "consultation" improperly circumvents the proper public review that would be provided by reaching a decision on the disposal requirements for water-based mud and associated cuttings through the environmental review process.

3.12.4 Hydraulic Fracture Additive Limitations

The RDSGEIS and proposed regulations continue to rely solely on the drilling operators to (1) regulate themselves, and (2) select the lowest toxicity chemicals for use in fracture treatment additives.

The proposed regulations require documentation that the additives exhibit "reduced aquatic toxicity" and "lower risk to water resources" compared to alternate additives or documentation that alternatives are not equally effective or feasible. There are no specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk. Operators would still be allowed to use harmful chemicals merely by stating to NYSDEC that these are the only chemicals that would be "effective" or by showing that the chemicals they propose are slightly less toxic than the most toxic alternatives.

To address this problem, the RDSGEIS and proposed regulations should identify the type, volume and concentrations of fracture treatment additives that are protective of human health and the environment; include a list of prohibited additives; and require the use of non-toxic materials to the greatest extent possible.
NYSDEC should develop the list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the New York State Department of Health (NYSDOH) has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the RDSGEIS as a mitigation measure and codified in the proposed regulations.

3.12.5 Centralized Surface Impoundments for HVHF Flowback Off-Drillsite

The 2009 DSGEIS disclosed significant adverse air quality impacts associated with centralized surface impoundments for HVHF flowback, which were found to emit over 32.5 tons of air toxics per year. However, this important impact information was removed from the RDSGEIS. Instead, NYSDEC improperly declined to analyze centralized surface impoundments based on statements by the industry that they would not "routinely propose" to use centralized flowback impoundments. The proposed regulations do not prohibit centralized surface impoundments, which would be appropriate

mitigation for the significant adverse impact identified in the 2009 DSGEIS, and instead a separate site-specific SEQRA review would be required for them.

3.12.6 Chemical and Waste Tank Secondary Containment

NYSDEC appropriately codified a requirement for secondary containment for chemical and waste handling tanks in the proposed regulations. However, the proposed regulations do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment. The regulations should be revised to address secondary containment for transport, mixing and pumping equipment in order to minimize potential soil and water resource impacts from chemical spills. There are several other minor modifications to the proposed regulations for secondary containment detailed in Chapter 21 of the Harvey Consulting, LLC report (Attachment 1) to eliminate inconsistencies between various regulatory requirements.

3.12.7 Fuel Tank Containment

NYSDEC appropriately included a requirement for fuel tank secondary containment in the Proposed Supplementary Permit Conditions. However, this requirement is confused by inconsistent statements in the RDSGEIS that secondary containment is not required for *temporary* fuel tanks (page 7-34). In addition to correcting this inconsistency, the proposed regulatory framework for fuel tank containment should be substantively improved to be more protective of the environment through adoption of the following changes:

- Define clear criteria for adequate containment (e.g., using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area).
- Include mandatory minimum setbacks from surface water features, homes and public buildings. The proposed regulations contain a setback for surface water resources, but only “to the extent practical.”
- Explain how NYSDEC’s requirements for fuel tank containment interface with federal requirements (40 CFR Part 112).
- Require tank inspections, spill prevention and spill alarm systems.
- Clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed in cases where secondary containment is impractical, and codify the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

3.13 Toxicology

This section addresses the toxicology-related issues associated with Naturally Occurring Radioactive Materials (NORM), hydraulic fracturing additives and waste disposal. For supporting technical information for these comments, refer to the technical reports of Dr. Glenn Miller (Attachment 3) and Dr. Ralph Seiler (Attachment 4).

3.13.1 Naturally Occurring Radioactive Materials

The Marcellus Shale is known to contain NORM concentrations at higher levels than surrounding rock formations. The primary environmental contamination risk associated with NORM is in production brines. Appendix 13 of the RDSGEIS presented some information on radioactivity

characteristics of vertical wells in the Marcellus Shale in New York. However, the data in Appendix 13 identifies only 14-24% of the gross alpha radiation sources in the water samples. The sources of the other 75%+ of alpha radiation are not identified. The RDSGEIS explicitly acknowledges that the scientific understanding of NORM in production brine is incomplete.[6] NYSDEC should have obtained more information on the radiation sources in production brine as part of the SGEIS process because it is essential to NYSDEC's decision-making process and for NYSDEC to ensure that adequate regulations are in place before widespread HVHF occurs in New York. Even if the information could not have been reasonably obtained (which is not the case here), the proper approach for SEQRA compliance would have been to disclose the unavailable information in accordance with NYCRR §617.9 (b) (6)[7]:

One possible source of the unspecified alpha levels in production brines is polonium. Polonium-210 is 5,000 times more radioactive than radium and is highly toxic.[8] Polonium-210 is difficult and expensive to remove from drinking water and bioaccumulates in the environment. Before completing the SEQRA process, NYSDEC should determine if polonium is a significant component of alpha emission in formation waters and identify appropriate regulations that address polonium-contaminated wastewater to prevent water resource impacts. Specific technical recommendations regarding the analyses that should be conducted to determine the presence of polonium are provided in Attachment 4. Attachment 4 also addresses the potential for Polonium-210 exposure via build-up in natural gas delivery pipes.

3.13.2 Radon Exposure via Natural Gas Combustion

Radon is a cancer-causing, radioactive gas. Radon is known to be present in natural gas and will be delivered with the natural gas to consumers. The quantity of radon in natural gas is highly variable and has not been studied by NYSDEC in the Marcellus Shale. While normal natural gas use in properly ventilated burners are unlikely to contribute to radon concentrations in a closed space, poorly vented areas may well be a problem, and certain scenarios (e.g., high use of natural gas for industrial applications, restaurants that use gas burners) need to be subjected to risk assessment. At the very least, substantially more radon measurements need to be made. The risk is likely to be greatest in those areas that already have elevated radon in air, and that risk may be enhanced by the natural gas contribution. Any increase in radon exposure in the Southern Tier is of particular concern in terms of cumulative impacts given that the NYSDOH estimates the majority of homes in

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[6] 2011 RDSGEIS Page 5-142: "The data indicate the need to collect additional samples of production brine to assess the need for mitigation and to require appropriate handling and treatment options…."

[7] *In addition to the analysis of significant adverse impacts required in subparagraph 617.9(b) (5) (iii) of this section, if information about reasonably foreseeable catastrophic impacts to the environment is unavailable because the cost to obtain it is exorbitant, or the means to obtain it are unknown, or there is uncertainty about its validity, and such information is essential to an agency's SEQR findings, the EIS must:*

(i) identify the nature and relevance of unavailable or uncertain information;
(ii) provide a summary of existing credible scientific evidence, if available; and
(iii) assess the likelihood of occurrence, even if the probability of occurrence is low, and the consequences of the potential impact, using theoretical approaches or research methods generally accepted in the scientific community.

This analysis would likely occur in the review of such actions as an oil supertanker port, a liquid propane gas/liquid natural gas facility, or the siting of a hazardous waste treatment facility. It does not apply in the review of such actions as shopping malls, residential subdivisions or office facilities.

[8] http://www.who.int/ionizing_radiation/pub_meet/polonium210/en/index.html

the region have existing basement radon levels above the EPA "action level" of 4 pCi/L. Between 20 and 40 percent of homes in the several Marcellus Shale counties have long-term exposure to radon levels above the EPA limit in their living areas.[9] Before completing the SEQRA process, NYSDEC should analyze the cumulative health risk posed by additional radon exposure from Marcellus Shale natural gas combustion so that appropriate mitigation measures can be identified to address the issue.

3.13.3 Hydraulic Fracturing Additives

The RDSGEIS does not present sufficient information to analyze the toxicology risks posed by hydraulic fracturing additives. It does not address the toxicology risks generically or at the site level. The proposed regulations do not require permit applicants to provide sufficient information for the risks of these additives to be considered at the site level. The RDSGEIS provides a long list of potential additives (Tables 5.4 and 5.5), but does not analyze their potential environmental impacts. The list of additives is almost certainly incomplete, specific information on the chemicals is lacking, and the specific rate of usage is not offered. Thus, not knowing the composition of the specific additives nor the amounts in which they would be used during the HVHF process there is no basis for estimating the risk of these components with regard to their presence in the produced flowback or produced water.

The RDSGEIS misrepresents the presence of hydraulic fracturing additives in flowback. Table 6.1 of the RDSGEIS states that no non-naturally occurring additives were detected. However, most of these additives cannot be detected through standard methods. Table 6.1 should be revised to indicate which additives were actually capable of being detected by the analytical methods selected and the associated detection limits. This is a customary practice and standard. The proposed regulations should require testing of flowback water for acrylonitrile, a non-naturally occurring chemical that if detected provides a clear indication of off-site contamination by hydraulic fracturing.

3.13.4 Disposal of Contaminated Wastewater

The water that flows back immediately following hydraulic fracturing is heavily contaminated, primarily with the Marcellus formation contaminants, and represents the most problematic chemical contamination potential, due to the large volumes of contaminated water generated. The produced brines that are released during production generally have higher concentrations of naturally occurring contaminants than flowback waster (although lower volumes) and similarly represent a serious chemical contamination potential. Four problematic components of the flowback water and produced brines are present: the radioactive component (NORM); the inorganic salts, metals and metalloids; the organic substances (from the hydrocarbon formation) and the hydraulic fracturing additives. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS. Reuse is not a

[9] http://www.wadsworth.org/radon/

complete disposal option because residual salts and other contaminants must still be managed. Beyond reuse, the disposal options considered in the RDSGEIS only included injection wells, municipal sewage treatment facilities (of which there are currently none that are permitted to accept flowback and produced water) and private treatment plants (of which none currently exist in New York). The RDSGEIS did not consider whether there are other, less environmentally harmful, options that exist for flowback and produced water. More importantly, the RDSGEIS fails to evaluate the potentially significant adverse environmental impacts and human health risks associated with these disposal options.

3.14 Air Quality and Odors

For supporting technical information for the comments provided in this section, refer to Chapters 17 and 20 of the Harvey Consulting, LLC report (Attachment 1).

3.14.1 Air Quality Modeling Assumptions

The air quality analysis in the RDSGEIS contains some substantial improvements compared to the DSGEIS, but the assumptions used still warrant additional review and justification. For example, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. In addition, the mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal). Limitations used in the modeling assumptions must all be translated into SGEIS mitigation measures and codified in the proposed regulations to ensure that the National Ambient Air Quality Standards will not be exceeded.

3.14.2 Air Quality Monitoring Program

The RDSGEIS includes a commitment to develop a regional air quality monitoring program to address the potential for significant adverse air quality impacts. However, more information is needed to understand the scope and duration of NYSDEC's proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

3.14.3 Greenhouse Gas Emissions Mitigation Plan

The RDSGEIS took a step in the right direction with the inclusion of a requirement for greenhouse gas emissions (GHG) impact mitigation plans. However, this requirement needs to be further defined. NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions

reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions. The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs. The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.4 Flare and Venting of Gas Emissions

Flares may be used during well drilling, completion, and testing to combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. During production operations, high pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. Reducing gas flaring and venting is widely considered best practice for reducing air quality impacts of natural gas development. The RDSGEIS air quality analyses of flaring assumed it would be limited to three days based on statements from industry, even though the actual duration should be longer. Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting restrictions should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.5 Reduced Emission Completions

Reduced Emission Completions (RECs, also known as "green completions") control methane and other GHG emissions following HVHF operations. RECs also reduce nitrogen oxide (NOx) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere. The RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of wellsites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale. Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a

mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.6 Gas Dehydrators

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. Gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions. The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement. In addition to this requirement, natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.7 Diesel Engine Emissions Control

NRDC's 2009 comments recommended limiting diesel engines to Tier 2 or higher. The RDSGEIS takes a step in the right direction by prohibiting "Tier 0" engines and requiring Tier 2 engines in most cases. To further strengthen air quality protection from diesel emissions SGEIS should examine whether it is possible to eliminate Tier 1 engine use altogether.

3.14.8 Leak Detection and Control

Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs. NYSDEC's proposed Leak Detection and Repair Program should be revised to require: a drillsite Leak Detection and Repair inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the proposed regulations, and be required for all natural gas operations, not just HVHF operations.

3.14.9 Cleaner Power and Fuel Supply Options

The RDSGEIS did not examine cleaner power and fuel supply options as was requested in NRDC's 2009 comments. In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where highline power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. These requirements should apply to all natural gas operations, not just HVHF operations.

3.14.10 Hydrogen Sulfide (H_2S) ("Sour Gas") Emissions

In addition to air quality risks associated with emissions of criteria pollutants and air toxics resulting from natural gas development, additional air quality risks can occur as a result of the release of hydrogen sulfide (H_2S) or sour gas. H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause very serious health symptoms, and can be deadly at the higher concentrations found in some oil and gas wells.

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public. The RDSGEIS does not analyze H_2S impacts based on the argument (supported by limited evidence) that to date H_2S has not been detected in high concentrations in HVHF operations in Pennsylvania. However, the early experience in Pennsylvania does not mean that there is no potential for H_2S issues to develop over time in New York.

A supplemental permit condition proposed in the RDSGEIS appropriately requires monitoring for H_2S during the drilling phase. However, a requirement should be added to the HVHF regulations to ensure that periodic monitoring occurs throughout production as gas fields age and sour. H_2S monitoring requirements should apply to all wells and therefore should be addressed through regulations, rather than through permit conditions that can be altered without public review. The regulations should stipulate that when monitoring detects H_2S, nearby neighbors, local authorities and public facilities should be notified of the risk of H_2S gas. They should be provided information on safety and control measures that the operator will be required to undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

3.15 Socioeconomics

This section addresses the socioeconomic impacts of HVHF. For supporting technical information for these comments, refer to the technical report from Dr. Susan Christopherson (Attachment 5).

3.15.1 NYSDEC's Socioeconomic Impact Analysis

Although NYSDEC has included more information on the social and economic impacts of gas development using HVHF in the RDSGEIS than it did in the 2009 draft, the RDSGEIS still does not effectively assess those impacts or provide appropriate mitigation strategies. There are a number of substantive concerns raised by the discussion of socioeconomic impacts presented in the RDSGEIS and by the Economic Assessment Report (EAR) prepared by NYSDEC's consultant, Environment and Ecology, on which that discussion is based.

1. The assessment of economic benefits (jobs and taxes) relies on questionable assumptions about the amount of gas extractable in the New York portion of the Marcellus Shale. The range of estimates for extractable gas appears to be skewed to the high end, leading to an overestimation of economic benefits.

2. The model used in the RDSGEIS to assess social and economic impacts presents natural gas development as a gradual, predictable process beginning with a "ramp-up" period and then proceeding through a regular pattern of well development over time. This model is misleading, and because many of the negative social and economic impacts of HVHF gas extraction (such as housing shortages followed by excess supply) are a consequence of unpredictable development, the model cannot appropriately assess those impacts.

3. The RDSGEIS does not assess public costs associated with natural gas development. A fiscal impact analysis of the base costs to the state and localities that will occur with any amount of HVHF gas development is required, along with an estimate of how costs will increase and accumulate as development expands.

4. The long-term economic consequences of HVHF gas development for the regions where production occurs are not addressed despite a widely recognized literature indicating that such regions have poor economic outcomes when resource extraction ends.

5. Mitigation of enumerated negative social and economic impacts of HVHF gas development is presumed to occur by means of phased development and regulation of the industry, but no evidence or information is provided to indicate whether, and if so how, that would occur.

3.15.2 Uncertainty and Volatility of Natural Gas Production and its Socioeconomic Impacts

The EAR's projections concerning population, jobs, housing, and revenue are predicated on the assumption of a regular, predictable roll-out of the exploratory, drilling, and production phases of the natural gas development process, rather than the irregular pattern typically associated with such development.

Natural gas drilling is a speculative venture and the commercially extractable gas from any particular well is uncertain. This central feature of natural gas development has critical implications for the economies of natural gas development regions. As production fluctuates, they may experience short- and medium-term volatility in population, jobs, revenues, and housing vacancies. The model used in the RDSGEIS to project socioeconomic impacts ignores those issues, however, and assumes instead that the HVHF natural gas development in New York will have a different pattern than that historically associated with such development. Rather than occurring in irregularly recurring waves (or "boom-bust cycles"), development in New York is assumed to be steady and predictable. Many of the economic benefits that the RDSGEIS and EAR associate with natural gas development are predicated on this unlikely gradual, regular development scenario, raising doubts about the projection of economic benefits based on that model.

The spatial distribution of impacts is also uneven. Some wells will have long production phases; others will have dramatic declines in productivity after a relatively short period. The uncertainties in the geographic extent of drilling and the potential for intensive development in "hot spots" have implications for social and economic impacts. If drilling is concentrated in particular locations rather than rolled out uniformly across sub-regions of the landscape (as was modeled in the RDSGEIS), wealth effects and tax revenues also will be concentrated in particular localities. The social and economic <u>costs</u> of spatially concentrated drilling, however, will be experienced across a much wider geographic area, because public services will be required in areas without HVHF development (and therefore not receiving tax revenues from drilling), but close enough to serve the transient population associated with the industry.

Contrary to the RDSGEIS' contention that the regularized development model "does not significantly affect the socioeconomic analysis," smoothing out the unpredictability and unevenness of development covers up many of the negative cumulative social and economic impacts that arise from the unpredictability of shale gas development. Finally, the RDSGEIS does not sufficiently model the resource depletion phase of the exploration, drilling, production, and resource depletion cycle and its implications for local and regional economies.

3.15.3 Economic Impact Study Fails to Address Costs

The 2011 RDSGEIS analyzes potential *economic benefits* of HVHF, but fails to provide the same level of analysis of the potential *costs* of HVHF. A central component of the EAR is use of a Regional Industrial Multiplier System (RIMS) model. This type of model is useful for comparing different types of investments and for examining inter-industry linkages, but it has a significant drawback as the central model for the RDSGEIS analysis of socioeconomic impacts because it can only project economic benefits. It cannot measure or assess the costs of proposed gas development using HVHF.

The RDSGEIS assumes, based on the RIMS model, that economic benefits from HVHF gas development, presumably including benefits to revenue, will be substantial, but there is no fiscal impact analysis or cost-benefit analysis to substantiate that assumption. A fiscal impact analysis is required, given that:

(1) Many purchases by drilling companies are tax exempt.

(2) Costs to the state that will reduce or offset tax revenues are not calculated.

(3) Substantial negative fiscal impacts are detailed in the EAR that are not quantified or fully acknowledged in the RDSGEIS, including public costs associated with the increased demand for community social services, police and fire departments, first responders, schools, etc., as well as costs associated with monitoring and inspection and infrastructure maintenance. Although experience in other shale gas plays demonstrates that these costs are likely, the RDSGEIS makes no attempt to calculate the costs and consider them in the context of a fiscal impact assessment.

(4) There is no analysis of the expected 2-3 year lag between immediate costs and anticipated revenues, during which communities will be faced with significant public service costs.

Given the inability of the EAR input-output model to address the costs of gas development and the significance of local and state costs to decisions about shale gas drilling in the state, revised EAR findings regarding costs must be prepared and an opportunity for public review and comment on the revised EAR afforded before the SGEIS is finalized.

3.15.4 Impacts on Other Industries

HVHF has the potential to have significant adverse effects on the viability of other industries in New York, particularly tourism and agriculture. In contrast with the pages of projected benefits from gas development, the RDSGEIS offers no detailed description and no quantitative analysis of the effects of HVHF development on existing industries and the associated impact on the state of New York's economy. This omission is particularly important for the counties defined in the EAR as "representative" because industries, including agriculture and tourism, are significant employers in those counties and are important to the overall economy of the State. There is no analysis of how the "crowding out" of existing industries may impact the regional or statewide economy or of the implications of the loss of industrial diversity to the long-term prospects for regional economic sustainability.

The inadequate assessment of the impacts on existing industries in the region that will be affected by HVHF gas development is problematic not only because the state does not have adequate information to assess costs and benefits of HVHF gas development, but also because negative impacts on industries such as tourism and agriculture, including dairies and wineries, will undermine

state investments intended to support those industries. Given the importance of these industries in the state and regional economy, the evidence that they will be negatively affected by HVHF gas development should have been analyzed in detail and quantified when possible.

3.15.5 Housing and Property Value Impacts

The potential impacts of HVHF on the housing supply, housing costs, and housing financing are inadequately addressed in the EAR. In addition, the social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed.

The report assumes that the current housing stock would be used to house any workers who move to the production region on a "permanent" (more than one year) basis. However, given the quality and age of the housing stock in the region, evidence from Pennsylvania indicates that it is likely that there will be a demand for new single-family housing. This new housing stock will create new and additional construction jobs, increasing population pressure, accelerating the "boomtown" phenomenon. This housing may also contribute to sprawl around urban population centers such as Binghamton. When drilling ceases, either or temporarily or permanently, the value of this new housing is likely to plummet. The social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed. These impacts pose environmental justice concerns and require mitigation strategies.

With respect to impacts on property value, the EAR authors found that having a well on a property was associated with a 22% reduction in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. Thus, "…residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights." (EAR, 4-114). The EAR's assumption of recovering property values after the completion of HVHF gas development does not take into account the potential for re-fracturing of wells to increase their productivity or the effects of waves of development in which drilling moves in and out of an area. The prospect of industrial activity is what drives down investment in regions open to boom-bust development and also negatively impacts property values. A more definitive analysis of impacts of on property values, including mortgage availability, in regions affected by drilling is needed.

3.15.6 Effects on Employment

The oil and gas industry is not likely to be a major source of jobs in New York, because of the project-based nature of the drilling phase of natural gas production (rigs and crews move from one place to another and activities are carried out at each well) and because of its capital intensity (labor is a small portion of total production costs). The emerging information on actual employment created in Pennsylvania in conjunction with Marcellus drilling shows much smaller numbers than industry-sponsored input-output models projected.

Although the industry points to years of drilling experience in New York, the oil and gas industry employed only 362 people in New York State in 2009 (0.01% of the state's total employment). 43% of those workers (157) were employed in Region C, the region where vertical natural gas drilling is most significant in New York. Wages for these workers constituted 0.04% of the wages in the two-county region with almost 4,000 active gas wells.

In contrast, nearly 674,000 New York jobs were sustained by tourism activity last year, representing

7.9% of New York State employment, either directly or indirectly. New York State tourism generated a total income of $26.5 billion, and $6.5 billion in state and local taxes in 2010. In the Southern Tier alone, the tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in 2008. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income. In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue.

The RDSGEIS assumes that as the industry "matures" in the region, local residents will be trained and hired for drilling jobs. If, as has been the case with vertical drilling in New York State and in the Western US shale plays, development follows a more irregular pattern, then the higher paid technical jobs are less likely to evolve into stable local employment. In addition, the jobs in ancillary industries (retail and services) are likely to disappear and reappear as rigs leave and re-enter the region at unpredictable intervals.

In addition, many of the highest paid jobs associated with HVHF will not be filled locally. Occupational employment statistics geographical analysis of petroleum engineers, one of the most common occupations in the oil and gas industry, indicates that the states with the highest employment in this occupation are Texas, Oklahoma, and Louisiana. This data suggests that the rural areas of New York that are likely to experience the most intensive gas development will not see an increase in highly skilled and highly paid jobs in petroleum engineering.

The creation of high-paying jobs as a result of expenditures in industries outside the extraction industry is also likely to occur <u>outside</u> the production region. This is important because regions where natural resource extraction takes place (and especially rural regions with little economic diversity) have been found to end up with poorer economies at the end of the resource extraction process. Although the EAR asserts that as the natural gas industry grows, more of the suppliers would locate to the representative regions and less of the indirect and induced economic impacts would leave the regions, no evidence is presented to substantiate this assumption. The more likely outcome is indicated by a study of the impact of gas drilling on Western State economies, which found that natural gas drilling may have positive fiscal impacts at the state level, but negative fiscal impacts for the regions in which it occurs.

3.15.7 Regional Plan of Development Approach to Mitigating Socioeconomic Impacts

The mitigation chapter of the RDSGEIS implies that negative impacts will be mitigated through the permitting process and a secondary level of review triggered by the operator's identification of inconsistencies with comprehensive land use plans. The measures are only advisory. The RDSGEIS proposes no requirements to mitigate adverse socioeconomic impacts in this process.

Mitigation measures should be developed that would require operating companies to submit plans for exploration and development in a county or counties to county planning offices for review of cumulative impacts and mitigation (for example truck traffic routing), a model used in Western U.S. drilling regions. Because the RDSGEIS acknowledges that the pace and scale of development are difficult to ascertain until exploration and production begin to proceed, it is critical that a permit and regional Plan of Development (POD) review process be set up that alerts local officials to the need for long term planning for land use, schools, public safety and public health. The POD, outlining the pace, scale, and general location in which development will occur enables local government to anticipate and develop strategies to mitigate cumulative impacts. The near-term projections of development activity should include all secondary facilities (e.g., water extraction, waste disposal,

pipeline construction) in the area to be affected. A POD would allow communities in that region to prepare for the disruption and negotiate the least disruptive and damaging development plan.

To further assist communities in planning for socioeconomic impacts, a series of reporting requirements should be incorporated into the RDSGEIS and regulations. As development activities begin and progress, the information provided in initial projections should be confirmed or revised on a semiannual basis. This information is critical to forecasting and meeting housing and service demands.

In addition, mitigation strategies need to be developed and described in the RDSGEIS that address long term costs to affected regions and the impacts of the resource depletion phase of the exploration, drilling, and development process, when population and jobs leave the region and tax revenues may be insufficient to pay for the capital investments made to serve the population influx during the drilling and production phases of development. Finally, mitigation strategies should include policies to prevent negative impacts on existing industries, including agriculture, tourism and manufacturing.

3.16 Traffic and Transportation

While the RDSGEIS improves upon the 2009 DSGEIS regarding estimates truck trip generation, the impact of HVHF on roadway congestion and safety has not been adequately addressed in the RDSGEIS.

The impacts of a typical multi-well development on congestion and safety should be analyzed in detail; such analysis should include a cumulative traffic effects analysis using a reasonable worst case development scenario. The reasonable worst case development scenario for regional traffic impacts should include indirect traffic generation associated with increased economic development and population growth attributable to natural gas extraction and related economic activity.

The LBG technical memo (Attachment 7) details the specific analyses that should be undertaken and describes how the transportation mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable. The transportation plan requirement in the RDSGEIS is a good first step, but additional detail is needed on the transportation plan including required contents, methodologies and impact criteria to make this mitigation measure meaningful.

3.17 Noise and Vibration

The construction and operation phase noise impact assessments presented in RDSGEIS are improved over the 2009 DSGEIS, but still contain important flaws that understate the impacts.

For example, the drilling and fracturing impact assessment presented is for one well, ignoring the cumulative impact of multiple wells being developed at the same time. Even using the analysis for a single well, the sound levels associated with the fracturing process are so extreme that hearing damage could result from exposure for 8-hours at a distance of 500 feet from the well pad.

Transportation-related noise impacts are not quantified in the RDSGEIS. Potential noise effects on wildlife are not evaluated, even though the noise of a single well and even more so the combination of noise of multiple wells could affect wildlife (especially sensitive bird species). The cumulative

effects of noise on wildlife habitat and fragmentation effects of almost continual disturbance are not evaluated.

Vibration impacts and low-frequency noise impacts (which are associated with health impacts) are similarly not addressed in the RDSGEIS. The LBG technical memo details the specific analyses that should be undertaken and describes how the noise mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable.

Similar to the transportation plan requirement mentioned above, the noise mitigation plan requirement lacks specificity regarding the analyses required and the thresholds that trigger the need for mitigation. A best practice template for NYSDEC to consider adopting to specify the requirements for noise impact analysis and mitigation plans is the Alberta Energy Resources Conservation Board (ERCB) Noise Control Directive (#38).

3.18 Visual Resources

The RDSGEIS describes in very broad terms the potential direct and cumulative impacts of various phases of natural gas development on NYSDEC-designated visually sensitive resources. This assessment should incorporate best practices for analyzing visual impacts, such as identifying the relevant view groups, landscape zones and photo simulations of well development in various contexts.

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would only be considered when designated significant visual resources (parks, historic resources, scenic rivers, etc.) are present *and* within the viewshed of proposed wells. This approach fails to consider visual impacts on nearby residences or tourists in areas where a significant visual resource is not present. In these situations, no mitigation would be required for individual wells to be consistent with the RDSGEIS. NYSDEC should make basic and low-cost mitigation measures mandatory for all well development sites (such as keeping lighting levels at the minimum level required and directing lights downward to minimize light pollution), regardless of whether or not state designated significant visual resources are present. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.19 Land Use

The RDSGEIS fails to provide any analysis of the reasonably foreseeable cumulative land use impacts that would result if HVHF development goes forward in New York. This should be corrected by providing information on existing land use patterns and analyzing the impact of the level of development anticipated in the economic impact study on land use change. The RDSGEIS fails to provide any discussion of mitigation measures for land use impacts. Mitigation measures such as buffer distances for incompatible land uses should be described and incorporated into enforceable regulations or supplemental permit conditions, as appropriate. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.20 Community Character

Community character is an amalgam of various elements that give communities their distinct "personality." These elements include a community's land use, architecture, visual resources,

historic resources, socioeconomics, traffic, and noise.[10] The community character impact assessment portion of the RDSGEIS lists some of the community character impacts that could be expected (focused on demographic and economic impacts), but does not analyze the significance of these impacts or draw conclusions on how HVHF would affect community character in the short-term and long-term. The impact assessment does not mention the contribution of visual, land use or historic resource impacts to community character. The discussion of traffic and noise impacts is superficial (two sentences each). A complete community character impact assessment is needed (including regional cumulative impacts) to ensure appropriate mitigation measures are included in the HVHF regulatory framework.

3.21 Cultural Resources

In addition to the ecological effects of the massive ground disturbance and industrial development that will occur with HVHF in New York, the integrity of historic architectural resources, archaeological sites and culturally significant areas to Native Americans is also threatened. The RDSGEIS does not address comments provided by New York Archaeological Council during scoping in 2008 on cultural resource issues and does not adequately address this important resource topic. There is no section of the RDSGEIS specifically devoted to the direct, indirect and cumulative impacts of HVHF on cultural resource or any discussion of mitigation measures (except for impacts related to visual resources). The reliance on the 1992 GEIS for protection of cultural resources is not sufficient given the significantly different type and scale of impacts that could occur with HVHF and the length of time that passed since the 1992 GEIS was prepared. The role of the New York State Office of Parks, Recreation and Historic Preservation (OPRHP) in the review of individual permit applications is not clear in the RDSGEIS. In addition, the RDSGEIS does not explained how tribal consultation regarding impacts to cultural resources will be accomplished in a manner consistent with NYSDEC's own 2009 policy *Contact, Cooperation, and Consultation with Indian Nations*. Cultural resource impacts, mitigation measures and project-level review requirements must be addressed before HVHF is approved. Refer to the LBG technical memorandum for more information supporting these comments (Attachment 7).

3.22 Ecosystems and Wildlife

The ecological effects of HVHF and related infrastructure development include direct losses of habitat, fragmentation of existing habitats and indirect "edge effects" such as the spread of invasive species and noise disturbance of wildlife. The RDSGEIS qualitatively acknowledges these impacts and summarizes the findings of studies conducted in other locations, but does not provide build-out analyses that could quantify the range of cumulative habitat loss and fragmentation effects in New York. As evidenced by The Nature Conservancy's build-out analysis of Tioga County, such an analysis is readily achievable with existing GIS tools and datasets available to NYSDEC.[11] The RDSGEIS should include quantitative build-out analysis of habitat fragmentation and edge effects using estimates of development potential consistent with those developed for the RDSGEIS economic impact assessment and include the impacts from reasonably foreseeable infrastructure such as pipelines and compressor stations. Based on the results of the build-out analysis, NYSDEC should also analyze the potential diminution of critical ecosystem services associated with the disruption of forest cover and soils (carbon sequestration and storage, air filtration, watershed flow rates and volume, surface water quality and thermal condition).

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[10] New York City Mayor's Office of Environmental Coordination. 2010. City Environmental Review Technical Manual.
[11] The Nature Conservancy. 2011 . "An Assessment of the Potential Impacts of High Volume Hydraulic Fracturing on Forest Resources."

The RDSGEIS characterizes the ecological impacts of HVHF as “unavoidable” and fails to consider alternative mitigation approaches that could lessen significant adverse environmental impacts. The site-specific ecological assessments and mitigation measures required by the RDSGEIS for well pads in grasslands greater than 30 acres and forest patches greater than 150 acres is a fragmented approach. It does not address the importance of landscape connectivity between habitat patches, which is essential to the movement and long-term viability of numerous species. A preferable methodology would be to set limits on deforestation, fragmentation and increases in impervious surface cover based upon ecological planning units such as the sub watershed. The SGEIS process should consider an alternative where rather than the current spacing unit requirements (which are intended to maximize production), land disturbance would be restricted region wide based on ecological carrying capacity. An ecologically oriented planning framework could significantly lessen the adverse impacts of HVHF development on terrestrial and aquatic systems.

In addition, consideration should be given to cumulative changes to land use within each watershed that could lead to detrimental changes in the affected stream to support critical species habitat. Limiting the percent increase in impervious area to less than five percent (inclusive of existing uses) in trout supporting watersheds, including upstream tributaries, would reduce the potential for adverse impacts to sensitive aquatic organisms and the loss of a waters best use designation.

The RDSGEIS fails to provide any meaningful guidance regarding the ultimate restoration of well pads, pipeline right-of-ways and access roads to full ecosystem functionality upon decommissioning. Effective restoration requires a comprehensive, site-level assessment of the existing plant community prior to disturbance and the use of local reference ecosystems as templates for restoration. Ecological restoration is based upon the concept of rebuilding degraded areas such that they are structurally and functionally similar to pre-disturbance conditions. Reclamation is not restoration. Grassy fields neither function in a biologically similar manner as a forest nor supply the ecosystem benefits of a forest system. The replacement of a decades-old, complex assemblage of woodland species with a simple mix of grasses is not “restoration”. It may retard erosion but it does not replace the original functionality and structure of the displaced ecosystem.

For supporting technical information for these comments and additional comments on ecological impacts and mitigation measures, refer to the technical report from Kevin Heatley (Attachment 8) and LBG (Attachment 7).

3.23 Climate Change

The RDSGEIS ignores the real possibility that climate change impacts will undermine the safety of HVHF operations, frustrate mitigation efforts proposed by NYSDEC, and therefore exacerbate adverse impacts to the environment and human health resulting from HVHF operations. Increases in extreme weather events, such as floods, pose considerable obstacles to the safety of HVHF operations and infrastructure in and around low-lying coastal areas and floodplains. Precipitation changes coupled with enormous surface and groundwater withdrawals may result in modified groundwater flow patterns, which may cause unexpected groundwater contamination that jeopardizes drinking water supplies. Increased temperatures can volatilize dangerous chemical compounds at drill sites, exposing workers and nearby residents to airborne carcinogens at a rate greater than would be expected by modeling baseline temperatures without climate change. Remarkably, the effect of climate change on the availability of water resources is ignored in the section on the cumulative impact of water withdrawals, and no provision is made for situations where HVHF operations and public needs may conflict over water usage. Underscoring these concerns is the notable failure of NYSDEC to conduct a comprehensive Health Impact Assessment, despite the real possibility that climate change impacts confluent with HVHF operations can pose serious human

health problems. Reliable reports on the effect of climate change on New York abound, including some produced within the last year by New York governmental bodies. The RDSGEIS fails to include current information relevant to climate change's potential effects on New York State, which may pose potentially significant adverse environmental and public health threats in conjunction with HVHF operations that should be identified and mitigated to the maximum extent possible.

For supporting technical information regarding these comments, refer to the technical report from Dr. Kim Knowlton (Attachment 9).

3.24 Health Impact Assessment

Numerous health concerns have been associated with natural gas development using hydraulic fracturing, and while the RDSGEIS addresses some aspects of a subset of these health issues, it fails to address other important health risks. The RDSGEIS not only omits several issues, but also it only addresses only some aspects of other issues such as air, water quality, and heightened traffic without fully considering health impacts in those areas. Lastly, it doesn't consider health issues as a group in a formal Health Impact Assessment (HIA), including interactive effects on the health of local residents and communities. A full HIA as part of the RDSGEIS is a necessary component, as there are already numerous reports of health complaints including dizziness, sinus disorders, depression, anxiety, difficulty concentrating, and many others, among people who live near natural gas drilling and fracturing operations in other states. Without a full assessment and mitigation of the impacts of the risks, the health of New York State residents and communities is likely to suffer.

For supporting technical information regarding these comments, refer to the technical report from Dr. Gina Solomon (Attachment 10).

3.25 Induced Seismicity

The RDSGEIS fails to require operators of HVHF wells to consider the risk of induced seismicity when siting wells and designing hydraulic fracture treatments. The justification provided is that high volume hydraulic fracturing is not expected to cause induced seismicity that will result in adverse impacts. Since the RDSGEIS was written, hydraulic fracturing has been confirmed to have caused induced seismicity strong enough to be felt at the surface. The RSDGEIS assumes that operators will manage seismic risks voluntarily and makes statements regarding the frequency of use of seismic monitoring techniques that are internally contradictory. It also fails to recognize the potential significance of unmapped faults and relies too heavily on the occurrence of natural seismicity as a future predictor of the potential for induced seismicity. Finally, it underestimates the potential adverse consequences of induced seismicity, which include risks to drinking water, well integrity, private and public property, and New York City drinking water supply infrastructure. The RSDGEIS provides insufficient analysis and scientific evidence to support its conclusion that regulations to reduce the risk of induced seismicity from hydraulic fracturing are not necessary. The RSDGEIS must require operators to evaluate and manage the risk of induced seismicity from hydraulic fracturing through proper site characterization and hydraulic fracture treatment design.

For supporting technical information regarding these comments, refer to the technical report from Briana Mordick (Attachment 11).

Attachment 1

Harvey Consulting, LLC.

2011 NYS RDSGEIS

Revised Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs and

Proposed Revisions to the New York Code of Rules and Regulations

Best Technology and Practice Recommendations

Report to:

Natural Resources Defense Council (NRDC)

Prepared by:

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

January 9, 2011

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Appendix A – Surface Casing Table
Appendix B – Intermediate Casing Table
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1. Introduction

This report responds to the Natural Resources Defense Council's (NRDC), and its partner organizations Earthjustice, Inc., Riverkeeper, Inc., Catksill Mountainkeeper and Delaware Riverkeeper Network, request for a review of the New York State (NYS) 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs and proposed revisions to the New York Code of Rules and Regulations (NYCRR).

NRDC, and its partners, requested a technical review of the RDSGEIS and the proposed revisions to the NYCRR to determine if best technology and practices were included. NRDC has also commissioned additional experts; therefore, this list of recommendations is not exhaustive and is complementary to the work assigned to other experts. A complete list of expert recommendations can be found in the summary cover letter submitted by The Louis Berger Group, Inc., on behalf of NRDC, to the New York State Department of Environmental Conservation (NYSDEC) during the RDSGEIS public comment period.

This report makes recommendations for improving the SGEIS and the proposed revisions to the NYCRR. Overall, HCLLC found that NYSDEC made a number of significant improvements in both the RDSGEIS and the proposed revisions to the NYCRR. HCLLC commends NYSDEC for integrating a number of new best practices and technology alternatives into its 2011 RDSGEIS and proposed regulations.

This report highlights the RDSGEIS areas of improvement and reinforces the importance of retaining those improvements in the final SGEIS and the proposed NYCRR revisions. However, there remain significant areas for improvement. This report provides additional technical justification and scientific support for best practices and technology that warrant further NYSDEC consideration. It also recommends area of further study. Recommendations are highlighted in blue text boxes throughout the document.

A systemic problem persists in the 2011 RDSGEIS, where NYSDEC proposes to build on the existing 1992 Generic Environmental Impact Statement (GEIS) for oil and gas drilling in NYS by providing additional information on the Marcellus Shale reservoir and high-volume hydraulic fracturing without addressing the fact that the technology and practices required by the 1992 GEIS are over two decades old.

Since 1992, numerous best technology and best management practice improvements have been made in the oil and gas industry. By relying on 1992-vintage decisions and technology as the foundation for Marcellus Shale development, NYS' RDSGEIS starts with an unstable foundation. This problem is magnified in the proposed revisions to the NYCRR where NYSDEC proposes to retain, with little revision, antiquated technology and practices for all oil and gas development in NYS, while proposing that new technology and practices only apply to HVHF operations. This creates a technically and scientifically unsupported two-tiered system for oil and gas regulation in NYS.

Accordingly, the first and most logical step in the State Environmental Quality Review Act (SEQRA) analysis is to examine the 1992 GEIS foundation and identify new best technology and best practice improvements have been made since 1992 that warrant adoption. Then, and only then, can NYS build a well-supported incremental analysis that examines the impact of new techniques such as horizontal drilling and high-volume fracture treatments.

2. Scope of SGEIS – Marcellus Only

Background: In 2009, NYSDEC proposed that the SGEIS cover all horizontal drilling and HVHF in low-permeability gas reservoirs, at all depths. However, only the Marcellus Shale Gas Reservoir was studied in any detail. The DSGEIS was incomplete for all other low-permeability gas reservoirs.

In 2009, HCLLC recommended that NYSDEC either include additional information and analysis on the impacts of exploring and developing other low-permeability gas reservoirs or limit the scope of the SGEIS to the Marcellus Shale Gas Reservoir.

NYSDEC's consultant, Alpha Geoscience, disagreed with HCLLC's recommendation to limit the SGEIS scope to the Marcellus Shale, stating that the time to modify the scope had lapsed.[1] Alpha Geoscience concluded that it would be best for NYSDEC to determine at a future date, once a specific application was before them, whether the SGEIS covered High-Volume Hydraulic Fracturing (HVHF) operations in other low-permeability reservoirs.

HCLLC disagrees with Alpha Geoscience's recommendation, because it lacks technical and scientific basis and misconstrues HCLLC's recommendation. HCLLC did not recommend that other low-permeability gas reservoirs be excluded from the analysis because they should not be studied at all. On the contrary, HCCLC recommended that if low-permeability gas reservoirs were included in the SGEIS, they should be thoroughly studied. The 2009 DSGEIS should have included a complete assessment of the Marcellus **and** all other low-permeability gas reservoirs in NYS; however, it did not. Unfortunately, the 2011 RDSGEIS suffers from the same lack of data on other low-permeability gas reservoirs.

Consequently, there is a technical and scientific choice that needs to be made in declaring whether the SGEIS content satisfies its title. Either the SGEIS had to be revised to cover all low-permeability gas formations in NYS, or the SGEIS had to conclude that NYSDEC has insufficient data and/or resources to examine anything more than the Marcellus Shale at this time, and limit the scope of the SGEIS.

HCLLC's 2009 recommendation was made to ensure the SGEIS document title matches its content. The title of the SGEIS purports to provide an environmental impact analysis on all low-permeability gas reservoirs, yet, as explained in HCLLC's 2009 comments, the SGEIS did not provide sufficient analysis of the Utica Shale, and provided no analysis of the other Lower Paleozoic, Devonian (other than Marcellus), and Middle to Upper Paleozoic low-permeability gas reservoirs.[2,3] If NYSDEC has additional information to support a complete SGEIS for the Marcellus **and** all other low-permeability gas reservoirs, it should certainly include that complete assessment.

Unfortunately, the 2011 RDSGEIS suffers from the same narrow focus on the Marcellus shale. There was little additional work completed to advance NYSDEC's understanding of exploration and development impacts from the Utica Shale and other low-permeability gas reservoirs.

[1] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 3.

[2] Ryder, R.T., 2008, Assessment of Appalachian Basin Oil and Gas Resources: Utica-Lower Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2008–1287.

[3] Milici, R.C., and Swezey, C.S., 2006, Assessment of Appalachian Basin Oil and Gas Resources: Devonian Shale-Middle and Upper Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2006-1237.

2011 RDSGEIS: The 2011 RDSGEIS provides some additional information on the Utica Shale Gas Reservoir, mostly in the form of geologic assessment. However, the RDSGEIS does not examine the peak or cumulative impacts of Utica Shale development.

No additional information is provided in the 2011 RDSGEIS on other low-permeability gas reservoirs in the region. The 2011 RDSGEIS states that industry's main focus in the near term is the Marcellus and Utica Shales; however, NYSDEC wants to cover all other low-permeability formations in the SGEIS because it may receive applications in the future for those formations:

> *The Department of Environmental Conservation (Department) has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus and Utica Shales for natural gas production…**Other shale and low-permeability formations in New York may also be targeted for future application of horizontal drilling and high-volume hydraulic fracturing** [emphasis added].* [4]

Chapter 4 provides a geologic description of the Marcellus and Utica shale gas reservoirs; however, no other low-permeability gas reservoirs are studied. Yet, it is well known that most unconventional reservoirs vary in mineralogy, permeability, rock mechanics, and natural fracture parameters (length, orthogonal spacing, connectivity, anisotropy) and that there will be differences between formations that could lead to different drilling, stimulation, and development techniques.

Chapters 5 and 6 provide an analysis of drilling, fracturing, and development approaches in the Marcellus Shale Gas Reservoir. Chapters 5 and 6 are essentially silent on how the Utica Shale Gas Reservoir would be developed. No other low-permeability gas reservoirs are examined.

A search of the 1537 page electronic version of the RDSGEIS for the term "low-permeability gas reservoirs" shows that the term is only used a few times in the entire document. This term is used twice in the Executive Summary, where NYSDEC concludes that it has effectively studied "low-permeability gas reservoir" air quality impacts; yet, as further explained in Chapter 17 of this report there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence of the term "low-permeability gas reservoirs" is not found until page 618 in the Air Quality Section, where again, NYSDEC states that it has included the impacts of "low-permeability gas reservoirs" in the air quality analysis; yet, there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence, after the Air Quality Section, is found at page 1008, where NYSDEC defends exclusion of pipeline and compressor stations. A few minor references to this term are found at page 1071 in Chapter 9 (Alternative Actions). More simply put, the RDSGEIS contents do not match the title, and that there is insufficient information contained in the RDGSEIS to support development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS. NYS has not developed a technical or scientific case to justify that the impacts described for the Marcellus Shale are representative of the peak or cumulative impact that would result from development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS.

The 2011 RDSGEIS does not include a complete list of the formation names that it considers fit under the umbrella term of "low-permeability" formations. The only place that the term "low-permeability" formation is defined is in the Glossary at the end of the document:

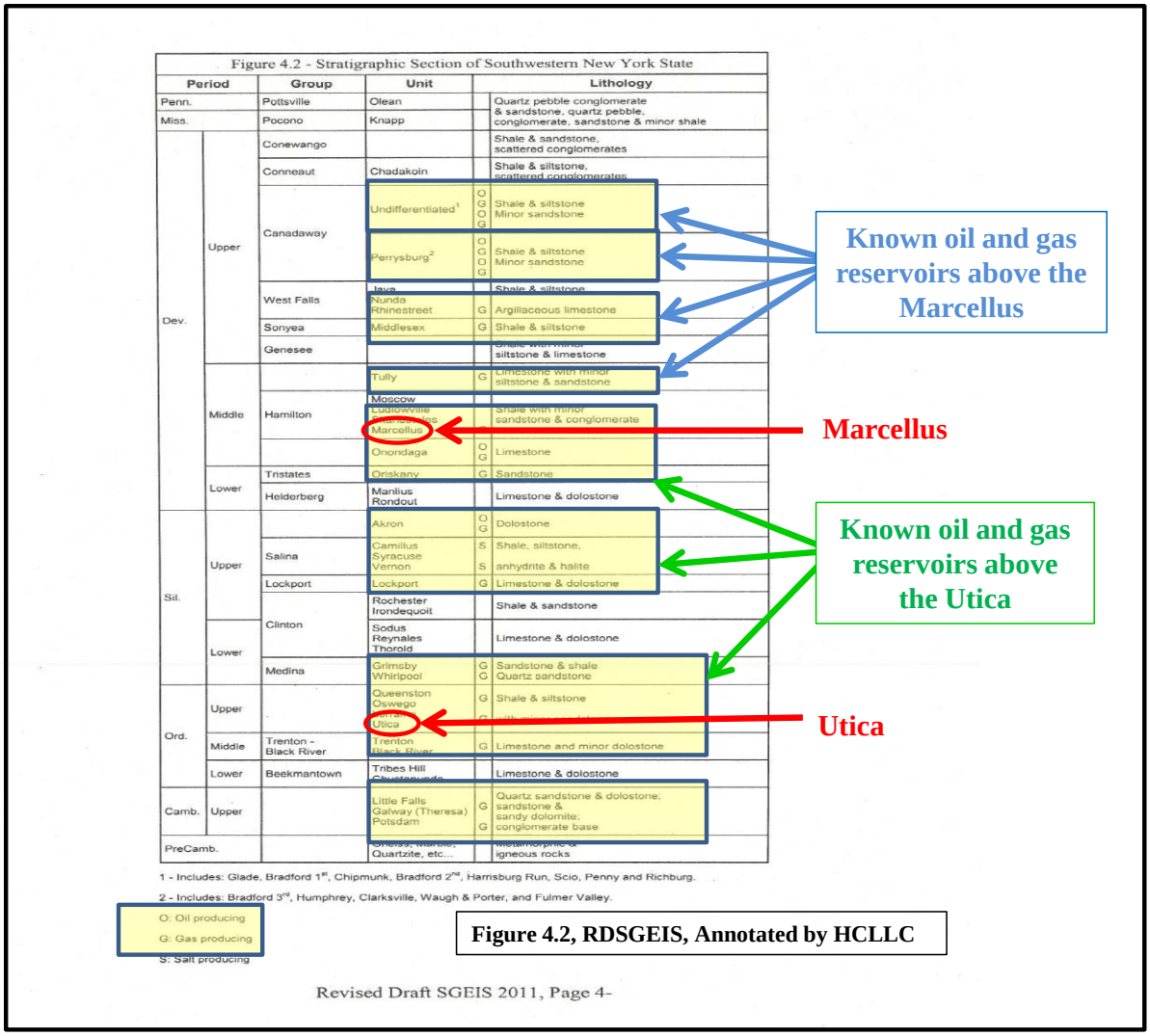
> *Gas bearing rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 0.10 milidarcies.*[5]

[4] 2011 NYSDEC, RDSGEIS, Page 1-1.

[5] 2011 NYSDEC, RDSGEIS, Glossary.

Using this definition, a low-permeability formation could include a shale, sandstone, limestone or other formation that is gas bearing with a permeability of less than 0.10 milidarcies. The RDSGEIS does not address the scope of the formations that could be encompassed by this definition.

Figure 4.2 of the RDSGEIS[6] includes a stratigraphic section showing existing known oil and gas intervals above the Marcellus and Utica Shales, including numerous shale and other low-permeability formations that are known to exist, that were not examined in the SGEIS.



On the next page is a table summarizing historical oil and gas production data from 1967 to 2010 in NYS.[7] This table shows that there is numerous gas zones present both above and below the Marcellus Shale that have been producing gas. Some of these reservoirs are low-permeability reservoirs that may be further developed using horizontal drilling and hydraulic fracturing techniques. Additionally, this table shows that there has been no Utica Shale production in NYS from 1967 to 2010; therefore, little is known about its productivity or how it may be developed.

[6] 2011 NYSDEC, RDSGEIS, Page 4-7.

[7] NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011, using NYS data found at http://www.dec.ny.gov/energy/1601.html. 1967-1999 data came from summary production history files. 2000-2010 data came from oil and gas production files.

NYS Oil & Gas Data Summary 1967-2010

		Formation	Oil (bbl)	Gas (mcf)		Oil (bbl)	Gas (mcf)
Devonian	Upper	DEVONIAN SHALE	12,274	323,975			
		UPPER DEVONIAN	364,054	881,848	DEVONIAN SHALE	376,328	1,208,697
		UPPER DEVONIAN SHALE	-	2,874			
		Canadaway Undifferentiated					
		GLADE	1,392,255	449,124			
		BRADFORD	7,665,427	1,639,511			
		BRADFORD 1ST & 2ND	21	-			
		BRADFORD & CHIPMUNK	416,357	676,506			
		Bradford 1st & Chipmunk	6,609	2,497			
		CHIPMUNK, BRADFORD 1ST & 2ND	44,943	10,217			
		CHIPMUNK	7,369,293	1,012,975			
		CHIPMUNK & BRADFORD 2ND	2,454,948	16,415			
		BRADFORD SECOND	21,724	2,520			
		CHIPMUNK, BRADFORD 2ND & 3RD	237,195	162,809	CANADAWAY UNDIFFERENTIATED	23,945,472	7,271,139
		Chipmunk, Bradford 1st,2nd,3rd	9,719	8,321			
		BRADFORD 2ND & 3RD	37,780	9,353			
		CHIPMUNK & BRADFORD 3RD	33,186	34,858			
		Chipmunk & Harrisburg	2,442	1,026			
		Harrisburg	1,682	-			
		SCIO	137,258	2,520			
		PENNY	13,232	46,567			
		PENNY & FULMER VALLEY	42,660	71,003			
		RICHBURG	4,057,637	3,121,677			
		RICHBURG-WAUGH & PORTER	1,104	3,240			
		Canadaway PERRYSBURG	-	395			
		BRADFORD THIRD	228,582	112,002			
		CLARKSVILLE	39,387	36,864	PERRYSBURG	2,055,287	4,746,392
		WAUGH & PORTER	42,100	247,245			
		FULMER VALLEY	1,745,218	4,349,886			
		Nunda	-	-			
		RHINESTREET	-	3,409			
	Middle	TULLY	1,108	275,643	TULLY	1,108	275,643
		HAMILTON	-	20,416	HAMILTON	-	20,416
		MARCELLUS	-	747,399	MARCELLUS	-	747,399
		ONONDAGA	647,251	25,843,114	ONONDAGA	647,251	25,843,114
		ONONDAGA-ORISKANY	-	223,157			
	Lower	ORISKANY	10,582	31,738,725	ORISKANY	10,582	31,961,882
		HELDERBERG	-	10,230,425	HELDERBERG	-	10,230,425
		ONONDAGA-BASS ISLAND	532,310	3,118,389			
Silurian	Upper	BASS ISLAND	1,021,802	5,739,620	BASS ISLAND	1,580,509	9,416,091
		BASS ISLAND/MEDINA	26,397	558,082			
		AKRON	1,577	1,729,358	AKRON	1,577	1,729,358
		SALINA	1,278	5,778			
		CAMILLUS	-	60			
		SYRACUSE	570	2,338			
		VERNON	-	358,405			
		CLINTON	-	87,231			
		LOCKPORT	-	69,528			
		ROCHESTER SHALE	-	70,693			
		SAUQUOIT	-	210			
	Lower	SODUS SHALE	-	164,071			
		MEDINA	213,688	514,545,705			
		GRIMSBY	-	1,501,854	MEDINA	213,688	521,205,687
		WHIRLPOOL	-	893,326			
		MEDINA-QUEENSTON	-	4,264,802			
		HERKIMER	-	5,849,567			
		HERKIMER-ONEIDA	-	1,178,375			
		ONEIDA	-	1,024,647	HERKIMER-ONEIDA-OSWEGO	-	9,169,025
		ONEIDA-OSWEGO	-	1,094,384			
Ordovician	Upper	QUEENSTON	-	56,439,648	QUEENSTON	-	56,439,648
		OSWEGO	-	22,052			
		UTICA	-	-			
	Middle	TRENTON	-	485,477	TRENTON	-	485,477
		BLACK RIVER	-	318,316,063	BLACK RIVER	-	318,316,063
Cambrian	Upper	LITTLE FALLS	-	501,440	LITTLE FALLS	-	501,440
		THERESA	-	3,588,222	THERESA	-	3,588,222
		POTSDAM	-	-			

NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011.

Using the Marcellus Shale impact assessment and proposed mitigation measures as a surrogate for peak and cumulative impact assessment in the Utica and all other unnamed low-permeability formations is an inadequate approach.

For example, the Utica Shale Gas Reservoir is almost twice as deep as the Marcellus Shale Gas Reservoir. The Utica Shale dips to 9,000' deep,[8] while the Marcellus Shale is approximately 5,000' deep.[9] Utica Shale wells will take longer to drill than Marcellus Shale wells, generating more air pollution and drilling waste, HVHF waste and resulting in longer duration surface impacts (e.g. noise, light, fuel and chemical storage periods, etc.). Additionally, waste generated translates into additional transportation and surface use impacts. Utica Shale development will also require more resources and equipment. Deeper shale gas formations will have higher reservoir pressure, and will penetrate more known oil and gas zones before reaching the Utica Shale, meaning increased blowout risk. Higher reservoir pressure will require additional combustion equipment to meet higher pump pressure and energy demands. Deeper wells can have more complex well construction designs. Fully cemented casing strings will be more difficult to complete at deeper depths and higher temperature cement mixtures will be required if subsurface temperatures exceed 200 ^{0}F. Therefore, the maximum impact assessment for a Marcellus Shale well is not sufficient to examine the maximum impact of a Utica Shale well.

Additionally, there is little information in Petroleum Engineering technical literature on the Utica Shale, and how it may be effectively developed. The 2011 RDSGEIS assumes that the Utica Shale will be developed using the same exact techniques as the Marcellus Shale; however, this may not be the case. For example, a 2007 a paper prepared by Universal Well Services Inc., CESI Chemical A Flotek Industries Co., in collaboration with the State University of New York noted some significant differences in the Utica Shale, and the likelihood for a unique stimulation method:

> *The primary purpose of stimulating fractured shale reservoirs is the extension of the drainage radius via creation of a long fracture sand pack that interconnects with natural fractures thereby establishing a flow channel network to the wellbore.* ***<u>However, there is limited understanding of a successful method capable of stimulating Utica Shale reservoirs. Indeed most attempts to data have yielded undesirable results</u>****. This could be due to several factors, including formation composition, entry pressure, and premature pad fluid leak-off. Furthermore, stimulation of Utica shale reservoirs with acid alone has not been successful. This treatment method leads to a fracture length and drainage radius less than expected resulting in poor well productivity [emphasis added].*[10]
>
> *…several recently drilled Utica shale wells have not responded well to the normal shale fracturing practices.* ***<u>An understanding of Utica shale mineralogy and rock mechanics is necessary before a stimulation method and fluid are selected</u>*** *[emphasis added].*[11]

Additionally, the authors point out that the Utica, unlike the Marcellus, contains a high percentage of acid soluble carbonate and dolomite that may require chemical treatment (e.g. acids) to treat the carbonates and dolomite to reduce entry pressures. They suggest that an acid stimulation treatment could potentially be the main stimulation method instead of a HVHF, or alternatively be added as an additional pre-

[8] 2009 NYSDEC, DSGEIS, Page 4-5.

[9] 2009 NYSDEC, DSGEIS, Page 4-14.

[10] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 1.

[11] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 2.

treatment to a HVHF. The Utica also contains a higher percentage of clays than the Marcellus, and has the potential to generate both siliceous and organic fines that may require additional chemical treatment.

Moreover, there are low-permeability gas reservoirs that are present at depths shallower than the Marcellus Shale, which were not studied at all. Those unnamed, unanalyzed low-permeability reservoirs are in closer proximity to protected water resources, and warrant a complete technical and scientific assessment. Most importantly, HVHF modeling and fracture design requirements should be established to ensure that man-made induced fractures in these shallower reservoirs do not propagate in a manner that pollutes protected groundwater resources. Man-made induced fractures in shallower formations will tend to propagate on the horizontal plane; however, the size of that horizontal fracture must be constrained so that it does not intersect with existing improperly constructed or improperly abandoned wells or transmissive faults and fractures that can provide a direct pollution pathway to protected groundwater resources.

Best technology and best practices and cumulative impacts, in many cases, are reservoir specific. Because the RDSGEIS does not contain information on the depth, type, activity, or equipment requirements for the general category called "***other*** *low-permeability gas reservoirs*," it is not possible to determine if the maximum impact assessment for a Marcellus Shale well sufficiently covers the maximum impact from "***other*** *low-permeability gas reservoirs*." Nor is it possible to determine whether best technology and best practices developed for the Marcellus Shale would apply to the Utica Shale since there is very little information and understanding of the optimal Utica Shale stimulation method at this time.

Recommendation No. 1: The SGEIS should either include additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the SGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

3. Liquid Hydrocarbon Impacts (Oil and Condensate)

Background: NYS 2009 Annual Oil and Gas Report[12] show that NYS produced 323,536 barrels of oil in 2009, primarily from the western counties of:

Cattaraugus	201,688 barrels
Allegany	47,421 barrels
Chautauqua	40,187 barrels
Steuben	9,992 barrels

NYSDEC did not separately report the amount of condensate or natural gas liquids production.

Chapter 2 of this report includes a table summarizing oil and gas production from 1967 to 2010 in NYS, showing that oil gas been produced from above the Marcellus and Utica Shale formations, verifying the potential to encounter liquid hydrocarbons while drilling into the Marcellus and Utica formations.

2011 RDSGEIS: The 2011 RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drillsites may be needed to develop those oil resources.

Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. [13] Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.[14,15]

The 2011 RDSGEIS provided several useful maps and a stratigraphic section that aid in understanding the overlap of NYS' oil and gas production intervals. Figure 4.2 includes a Stratigraphic Section of Southwestern NYS that shows oil is produced from the Upper Devonian, at shallower depths than the Marcellus Shale, meaning that wells drilled in this region may encounter oil before penetrating the Marcellus. An annotated version of Figure 4.2 is also shown in Chapter 2 of this report. Figures 4.8 and 4.9 indicate that there is an overlap of current oil production with possible Marcellus Shale development in Cattaraugus, Allegany, Chautauqua, and Steuben counties.

Oil is also found below the Marcellus Shale and above the Utica Shale in the Upper Silurian. Therefore wells drilled into the Utica Shale may encounter oil before penetrating the Utica. Figure 4.6 indicates that there is an overlap of current oil production with possible Utica Shale development in Steuben County.

[12] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009.

[13] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[14] Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

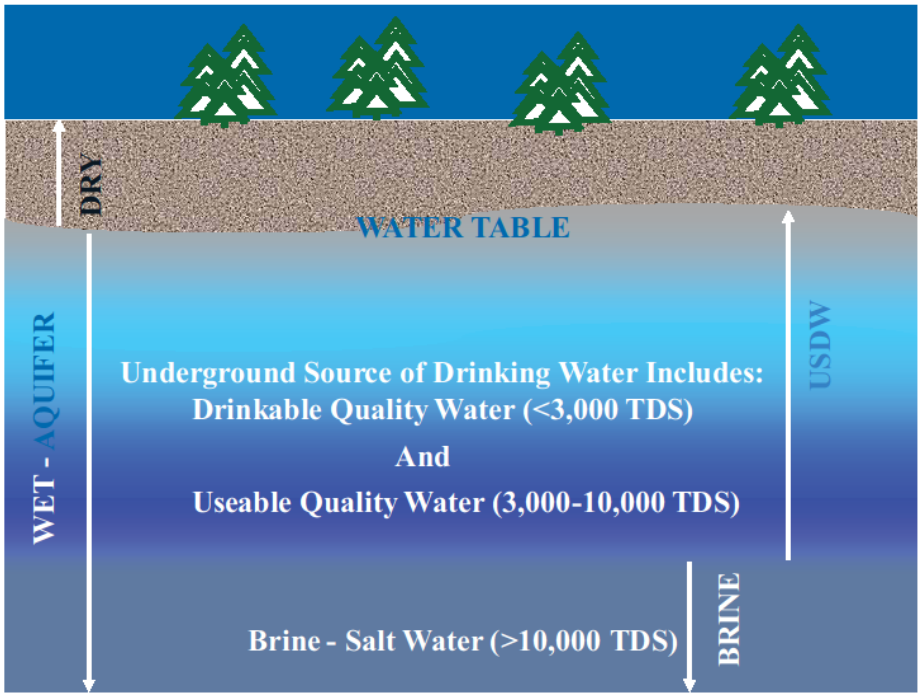
[15] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

There are low-permeability gas reservoirs that are present at depths both shallower and deeper than the Marcellus Shale, which were not studied in detail in the RDSGEIS. Absent geologic maps for these unnamed, unanalyzed low-permeability reservoirs, it is not clear where oil development and shale gas development overlap for these reservoirs may occur.

Recommendation No. 2: The SGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The SGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drillsites that may be required to develop oil resources identified by shale gas exploration and production activities.

4. Water Protection Threshold

Background: The regulations promulgated under the federal Safe Drinking Water Act (SDWA) define an Underground Source of Drinking Water (USDW) as an aquifer or part of an aquifer, which is not exempted (per 40 CFR § 146.4), and: (1) which supplies a public water system; or (2) which contains a sufficient quantity of groundwater to supply a public water system and either supplies drinking water for human consumption or contains fewer than 10,000 milligrams/liter of Total Dissolved Solids (TDS) [10,000 ppm TDS]. 40 CFR § 144.3. An EPA diagram depicting a USDW is shown below.[16]



The 2011 RDSGEIS: The 2011 RDSGEIS is based on the protection of potable water as defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS. The RDSGEIS states:

> *For oil and gas regulatory purposes, **potable fresh water is defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS** and salt water is defined as containing more than 250 ppm sodium chloride or 1,000 ppm TDS [emphasis added].*[17]

The RDSGEIS identifies 850' as the depth where 250 ppm of sodium chloride or 1,000 ppm TDS is typically reached, however the RDSGEIS notes that in some cases potable water is found deeper than 850'.

[16] USEPA, Karen Johnson, Chief Ground Water & Enforcement Branch, 2010 PowerPoint Presentation, EPA's Underground Injection Control Program, Regulation of Disposal Wells in Pennsylvania.

[17] 2011 NYSDEC, RDSGEIS, Page 2-23.

> ***Groundwater from sources below approximately 850 feet in New York typically is too saline for use as a potable water supply; however, there are isolated wells deeper than 850 feet that produce potable water*** *and wells less than 850 feet that produce salt water. A depth of 850 feet to the base of potable water is commonly used as a practical generalization for the maximum depth of potable water; however, a variety of conditions affect water quality, and the maximum depth of potable water in an area should be determined based on the best available data [emphasis added].*[18]

By comparison, USDWs are based on a TDS cutoff of 10,000 ppm. The RDSGEIS has not explained why it proposes, and NYS regulations rely on, a 1,000 ppm TDS threshold instead of the federally required USDW threshold of 10,000 ppm TDS.

Ohio issued updated Oil and Gas Well Construction Rules on October 28, 2011, that require surface casing and intermediate casing to be set to protect the deepest underground source of drinking water (USDW); Ohio's rules are based on the 10,000 ppm federal TDS threshold.[19]

Recommendation No. 3: The SGEIS and the NYCRR should require wells to be constructed to protect Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act.

NYS' use of a 1,000 ppm TDS cut-off instead of the USDW threshold of 10,000 ppm TSD is a two-fold problem: First, the RDSGEIS states that surface casing ("water protection piping") setting depths will be 925' if no other data is available.[20] The 925' surface casing setting depth is based on an 850' base plus 75'[21], where NYSDEC has assumed that TDS will exceed 1,000 ppm at deeper than 850'. The 925' casing setting depth does not take into account the fact that drinking water, under the SDWA definition of a USDW, could exist at depths below 850'. Therefore the RDSGEIS has not provided scientific justification for the default 925' casing setting depth, nor has it explained how such a proposal comports with federal law.

Second, the entire RDSGEIS is premised on the conclusion that a HVHF well initiated at a depth of 2,000' would be safe, because NYSDEC assumes that NYS does not have any drinking water resources deeper than 850' deep. However, the RDSGEIS does not indicate that any examination of the depth of 10,000 ppm TDS water or of the availability of drinking water resources below 850' has been or will be conducted and, therefore, cannot support its 850' assumption.

Additionally, the RDSGEIS states that potable water is found deeper than 850'. Therefore, the 2,000' threshold depth for initiating a HVHF under this SGEIS requires re-evaluation. And as explained in Chapter 10 of this report, HCLLC is recommending that initial drilling and completions occur below 4,000', while site-specific data is gathered in NYS to justify safe drilling at shallower depths.

[18] 2011 NYSDEC, RDSGEIS, Page 2-23.

[19] Proposed Ohio Oil and Gas Well Construction Rules, October 28, 2011, currently under public review and comment.

[20] 2011 NYSDEC, RDSGEIS, Page 7-50.

[21] See Chapter 6 of this report, where a 100' buffer is recommended, instead of 75'.

Recommendation No. 4: The SGEIS should re-examine the 925' casing default setting and the 2000' HVHF cut-off, and justify how these proposed thresholds will protect USDW sources. Protecting to a 10,000 ppm TDS standard will likely increase both depths.

The SGEIS should include data on the location of Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act, across NYS. The SGEIS should include USDW maps for all areas that will be affected by the proposed scope of the SGEIS. This data will be an important tool for industry and the public alike to ensure USDWs are protected.

NYCRR Proposed Revisions: Well construction regulations at 6 NYCRR § 550-559 instruct operators to construct oil and gas wells in a manner that protects potable fresh water, i.e., only water containing less than 250 ppm of sodium chloride or less than 1,000 ppm of TDS. 6 NYCRR § 550.3 (ai).

The NYCRR does not protect, under its definition of "potable fresh water," water resources with less than 10,000 ppm TDS but greater than 1,000 ppm TDS, which could qualify as USDWs under the Safe Drinking Water Act. See 40 CFR §§ 144.3, 146.4.

Regulations at 6 NYCRR § 554.1 require operators to prevent pollution to "surface or ground fresh water"; however, this term is not defined by the NYCRR, so it is unclear what additional groundwater beyond "potable fresh water" would be protected or how.

Recommendation No. 5: The NYCRR should be consistent with federal law [Underground Sources of Drinking Water (USDWs)] or NYSDEC should propose more protective standards for NYS if needed to protect NYS' future water supply needs, if the federal threshold is found insufficient.

5. Conductor Casing

Background: In 2009, HCLLC recommended the NYCRR and the SGEIS be revised to include conductor casing construction standards. While a number of changes were made to improve conduct casing requirements in the RDSGEIS, the proposed revisions to the NYCRR do not include conductor casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on conductor casing and the technical basis for HCLCC's recommendations.

Conductor casing construction standards are only partially addressed in the 2011 RDSGEIS, under Appendix 10, Proposed Supplementary Permit Conditions for HVHF, and Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers**.**

2011 RDSGEIS: The 2011 RDSGEIS Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, includes a conductor casing requirement that limits drilling fluid types. The requirement excludes synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*

Excluding synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore is a best practice.

Appendix 9 also includes procedures for ensuring conductor pipe is cemented from top to bottom, and firmly affixed in a central location in the wellbore, with a continuous, equally thick layer of cement around the pipe.

> *If conductor pipe is used, it must be run in a drilled hole and it must be cemented back to surface by circulation down the inside of the pipe and up the annulus, or installed by another procedure approved by this office. Lost circulation materials must be added to the cement to ensure satisfactory results.*
>
> *Additionally, at least two centralizers must be run with one each at the shoe and at the middle of the string. In the event that cement circulation is not achieved, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the conductor casing and squeeze cementing of perforations. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*

The 2011 RDSGEIS Appendix 10, Proposed Supplementary Permit Conditions for HVHF, includes a conductor casing condition that states:

> *When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the well bore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, three feet in diameter and shall be crowned up to the drive pipe (conductor casing), unless otherwise approved by the Department.*

NYCRR Proposed Revisions: In summary, NYSDEC has included important conductor casing construction guidelines in the 2011 RDSGEIS for wells drilled in primary and principal aquifer areas and HVHF wells, but has not proposed to codify those changes in the NYCRR.

The conductor casing construction guidelines listed in the 2011 RDSGEIS should apply to all wells in NYS, and should not just be limited to wells drilled in primary and principal aquifer areas and HVHF wells. These are best practices for construction of all oil and gas wells.

NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide solid structural anchorage. Also, the regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

Recommendation No. 6: Conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the NYCRR and should apply to all wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

6. Surface Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional surface casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on surface casing the technical basis for HCLCC's recommendations.

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well.

The drilling engineer determines the depth of surface casing installation with these key factors in mind: surface casing should stop above any significant pressure or hydrocarbon zone, ensuring the blowout preventer can be installed prior to drilling into a pressure or hydrocarbon zone, and surface casing should provide a protective barrier to prevent hydrocarbons from contaminating aquifers when the well is drilled deeper (below the surface casing) into hydrocarbon bearing zones.

Stray gas may impact ground water and surface water from poor well construction practices. Properly constructed and operated oil and gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion.

Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania.[22] Gas well leaks from improperly constructed gas wells have resulted in contamination of the Susquehanna River and adjacent private water supply wells.[23] A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. Duke University found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[24]

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for surface casing. Overall, NYS' surface casing requirements are fairly robust when the NYCRR, guidance documents, and standard stipulations are combined. NYSDEC proposed a number of substantial improvements in the surface casing requirements, most notably improved cement quality, casing quality, and installation techniques.

This chapter reviews the proposed changes and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and adds a few additional recommendations for NYSDEC to consider in completing its surface casing regulatory program revision.

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[22] *See, e.g.*, DEP Reaches Agreement with Cabot to Prevent Gas Migration, Restore Water Supplies in Dimock Township, Agreement Requires DEP Approval for Well Casing, Cementing, November 4, 2009, available at http://www.portal. state.pa.us/portal/server.pt/community/newsroom/14287?id=2418& typeid=1.

[23] *See, e.g.*, DEP Monitors Stray Gas Remediation in Bradford County Requires Chesapeake to Eliminate Gas Migration, Chesapeake Commits to Evaluate, Remediate All PA Wells to Conform with Improved Casing Regulations, September 17, 2010, available at http://www.portal.state.pa.us/portal/server.pt/ community/newsroom/14287?id=14274&typeid=1.

[24] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane contamination of drinking water accompanying gas- well drilling and hydraulic fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, Page 2.

The main recommendation in this section is to streamline surface casing regulations by amending the NYCRR to include requirements contained in the 2011 RDSGEIS and standard stipulations. As proposed, NYSDEC has included a number of surface casing requirements in the 2011 RDSGEIS at Appendices 8, 9, and 10 (Proposed Permit Conditions). NYSDEC also included some, but not all, of these requirements in the NYCRR. Unfortunately, there are a number of inconsistencies between the permit conditions and the NYCRR that create uncertainty about what will be required.

Additionally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in NYCRR Part 560 (drilling practices for HVHF wells).

In 2009, HCLLC recommended that improved casing and cementing practices be codified in the NYCRR, rather than through a combined patchwork of permit conditions and regulations. HCLLC's concern was that the proposed requirements, in a number of cases, were inconsistent with existing regulations, and could be more efficiently consolidated into a single, more concise set of regulations.

NYSDEC's consultant Alpha Geoscience disagreed. Alpha Geoscience concluded that it would be more logical to use a patchwork of regulations, add a long list of conditions to each permit, and forgo regulatory revision.

> *Harvey Consulting suggests that NYSDEC revise the NYS oil and gas regulations to specifically address new casing and cementing practices and fresh water aquifer supplementary permit conditions. The purpose of the SGEIS, however, is not to revise regulations. The purpose of the Proposed Supplementary Permit Conditions for shale gas activities is to customize the existing regulations and guideline framework to fit new and changing industry, relieving the need for frequent regulatory changes. Permit conditions must be met by the party seeking a permit for a proposed action, so whether or not the permit conditions are included in the New York State regulations is irrelevant.*[25]

HCLLC disagrees with Alpha Geoscience's recommendation. It is relevant whether new requirements are found in regulation or a permit condition. Foremost, revising the outdated NYCRR provides simplicity and clarity for industry and the public. It provides a concise set of co-located rules. Conversely, layering a complex patchwork of permit conditions on outdated NYCRR creates confusion, inconsistency, and enforcement challenges. Furthermore, permit conditions can be revised and modified by staff, without public review, and can be applied in a more discretionary manner. Regulations are not discretionary, and are not subject to modification without a formal public review process. Therefore, HCLLC recommends that requirements that apply to all wells be codified in the NYCRR, and permit conditions be reserved for site-specific, project-specific requirements. This will improve clarity and certainty for industry and the public alike, and will afford NYSDEC the opportunity to apply site-specific, project specific requirements to address unique project issues.

NYSDEC evidently agreed with HCLLC's recommendation to revise the NYCRR by proposing revisions for public review; however, the regulations have only been partially updated to include new surface casing best practices. Therefore inconsistency remains, and needs resolution.

Recommendation No. 7: The surface casing and cementing requirements should be consistent throughout the SGEIS text and with the NYCRR.

[25] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 13.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below and compared to the proposed NYCRR revisions. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: It appears that NYSDEC's intent is to require that all wells meet the minimum standards found at Appendix 8 (NYSDEC's Casing and Cementing Practices), and then layer on additional requirements for wells drilled in primary and principal aquifers (Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers). It appears that a third layer of requirements will be applied to wells that undergo HVHF stimulation treatments (Appendix 10 Proposed Supplementary Permit Conditions for HVHF).

Therefore, it is assumed that a shale gas well that is drilled in a primary and principal aquifer, and will undergo a HVHF stimulation treatment must meet all the conditions found in Appendices 8, 9, and 10; however, this would not be possible because the permit conditions are discordant. An evaluation of these layered conditions reveals inconsistencies, as explained in the text and summary table below.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires: surface casing be set at least 75' below freshwater or at least 75' into bedrock, whichever is deeper; surface casing be set before hydrocarbons are encountered; new pipe be used (or used pipe if tested); and centralizers and cement baskets be used.

> 2. *Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper, unless otherwise approved by the Department. However, the surface pipe must be set deeply enough to allow the BOP [blow-out preventer] stack to contain any formation pressures that may be encountered before the next casing is run.*
>
> 3. *Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).*
>
> 4. *All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi), unless otherwise approved. Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.*
>
> 5. *Centralizers shall be spaced at least one per every 120 feet; a minimum of two centralizers shall be run on surface casing. Cement baskets shall be installed appropriately above major lost circulation zones.*[26]

Appendix 8 requires the use of: 25% excess cement, spacer fluids between the drilling muds and cement, and lost circulation additives. Appendix 8 also requires that gas flows or lost circulation be addressed and

[26] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 1.

the hole be conditioned before cementing. NYSDEC reserves the right to require a cement evaluation log if cement does not return to the surface.

> 6. *Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the bore hole spacer or extra cement shall be used to separate the cement from the bore hole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.*
>
> 7. *The pump and plug method shall be used to cement surface casing, unless approved otherwise by the Department. The amount of cement will be determined on a site-specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless other amounts of excesses are approved or specified by the Department.*[27]

Appendix 8 requires: the water used in the cement be tested for pH and temperature; the cement be prepared according to manufacturer specifications; and the cement be allowed to harden to a compressive strength of at least 500 psi before being disturbed.

> 8. *The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing ticket.*
>
> 9. *The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.*
>
> 10. *After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The waiting-on-cement (WOC) time shall be recorded on the drilling log.*[28]

The 2011 RDSGEIS Appendix 9: Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, applies to wells drilled in primary and principal aquifer zones. Appendix 9 includes conditions that require: surface casing to be set at least 100' below the deepest freshwater zone and at least 100' into bedrock; the annulus be at least 1-1/4" wide to optimize cement placement and cement sheath width: the entire annulus be cemented, using at least 50% excess cement; the cement design include additives to control lost circulation; centralizers be run at least every 120'; new pipe be used (or reconditioned tested pipe); and NYSDEC be notified and present for cementing operations.

[27] 2011 NYSDEC, RDSGEIS, Appendix 8, Pages 1-2.

[28] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

> *A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. If shallow gas is known to exist or is anticipated in this bedrock interval, the casing setting depth may be adjusted based on site-specific conditions provided it is approved by this office. There must be at least a 2½" difference between the diameters of the hole and the casing (excluding couplings) or the clearance specified in the Department's Casing and Cementing Practices, whichever is greater. Cement must be circulated back to the surface with a minimum calculated 50% excess. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, cement baskets and centralizers must be run at appropriate intervals with centralizers run at least every 120'. Pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 psi or reconditioned pipe that has been tested internally to a minimum of 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to this office before the pipe is run. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*[29]

Appendix 9 requires the surface hole be drilled using compressed air or Water-Based Muds (WBM), meaning no Synthetic-Based Muds (SBM) or Oil-Based Muds (OBM) may be used.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*[30]

As found in Appendix 9, freshwater zone depths and the potential for shallow gas hazards must be estimated and documented in drilling applications; actual data must be collected during drilling to identify any freshwater zones and shallow gas hazards that require additional NYSDEC review and approval.

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.* [31]

Appendix 9 requires cement fill the surface casing annulus, and if cement placement in the annulus is not initially successful, additional cement must be pumped into the annulus until it is filled with cement.

> *In the event that cement circulation is not achieved on any surface casing cement job, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. This office must be notified _____ hours prior to cementing operations and cementing cannot commence until a state inspector is present. In lieu of or in*

[29] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[30] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[31] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

> *combination with such grouting or squeezing from the surface, this office may require perforation of the surface casing and squeeze cementing of perforations.* [32]

In Appendix 9, NYSDEC reserves the right to require the operator to run a cement bond log; however, it does not require one to verify the integrity of all surface casing cement jobs.

> *This office may also require that a cement bond log and/or other logs be run for evaluation purposes. In addition, drilling out of and below surface casing cannot commence if there is any evidence or indication of flow behind the surface casing until remedial action has occurred. Alternative remedial actions from those described above may be approved by this office on a case-by-case basis provided site-specific conditions form the basis for such proposals.*[33]

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional surface casing requirements. The 2011 RDSGEIS does not explain why these additional pollution prevention and quality control/quality assurance (QC/QA) requirements do not apply to all oil and gas wells in NYS.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
>
> *b) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
>
> *c) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
>
> *d) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[34]

[32] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[33] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[34] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

Appendix 10 also requires: drilling mud be circulated and conditioned prior to cementing; spacer fluid be used to separate the drilling mud from the cement, to avoid drilling mud contamination; and cement be installed using methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond… The surface casing must be run and cemented immediately after the hole has been adequately circulated and conditioned.*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…*[35]

Appendix 10 establishes a specific period of time for the cement to harden, and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> > *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
> >
> > *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[36]

Appendix 10 requires records be kept for a period of 5 years and be available to NYSDEC upon request.

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[37]

[35] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[36] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[37] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 reserves the right for NYSDEC to require additional casing strings to be set in the well if the surface casing fails to adequately protect water resources or poses a safety hazard.

> *38) The installation of an additional cemented casing string or strings in the well as deemed necessary by the Department for environmental and/or public safety reasons may be required at any time.*[38]

Appendix 10 requires NYSDEC's Casing and Cementing Practices be followed. NYSDEC's Casing and Cementing Practices are included in the 2011 RDSGEIS as Appendix 8. Yet, a number of the Casing and Cementing Practices found in Appendix 8 conflict with the new requirements in Appendix 10 for wells subject to HVHF.

The RDSGEIS does not provide a rationale or basis for the use of a 75' surface casing setting depth for some wells and a 100' surface casing setting depth for others. NYSDEC determined that a 100' setting depth is best practice for groundwater protection in areas of primary and principal aquifers, but does not explain why a 100' standard would not be best practice for all wells, or at least wells that undergo HVHF.

An analysis of the surface casing permit condition requirements and inconsistencies is provided in table format as Appendix A. Recommendations are listed in the table.

NYCRR Proposed Revisions: A number of the requirements listed in the RDSGEIS Appendices 8, 9, and 10 are not codified in the NYCRR, or conflict with the proposed changes to the NYCRR.

Listed below is an analysis of the proposed NYCRR revisions for surface casing and cementing. Specific recommendations for improving surface casing design, installation, and quality control/ quality assurance requirements are also included.

Surface Casing Setting Depth: 6 NYCRR § 554.1(d) requires that:

> *Surface casing shall be run in all wells to extend below the deepest potable fresh water level*.

Neither the 75' nor the 100' setting depths below the deepest protected water zone (described in the RDSGEIS) are specified in regulation. Furthermore, this regulation only protects "potable fresh water." As explained in Chapter 4 of this report, NYSDEC should consider its long-term water needs.

> **Recommendation No. 8**: 6 NYCRR § 554.1(d) should be revised to require the surface casing setting depth to be at least 100' below protected groundwater for all wells, or NYSDEC should provide a technical justification for reducing the setting depth to 75' for some wells.

Surface Casing Definition: 6 NYCRR § 550.3(au) reads:

> *Surface casing shall mean casing extending from the surface through the potable fresh water zone*.

This definition requires surface casing be set through only the protected water zone, and does not require the casing be set deeper. This definition, as written, does not include the important requirement for the casing to be set at least 100' below protected groundwater and be cemented in place.

[38] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 8.

Recommendation No. 9: 6 NYCRR § 550.3(au) should be revised to read: surface casing shall mean casing installed and cemented from the surface, through protected groundwater, to a point at least 100' below the deepest protected groundwater. Protected groundwater should be defined in a way that meets NYS' long-term water needs.

Rotary Tool Drilling Practices: 6 NYCRR § 554.4 should be revised to be consistent with the proposed RDSGEIS surface casing conditions, and remove reference errors. 6 NYCRR § 554.4(a) provides the operator with a choice of installing surface casing in accordance with 6 NYCRR § 554.1(b) (which does not provide specific instruction to the operator) or by cementing the production casing from below the deepest potable fresh water level to the surface (which does not provide specific instruction to the operator).

§554.4 Rotary tool drilling practices

(a) On all wells where rotary tools are employed, and the subsurface formations and pressures to be encountered have been reasonably well established by prior drilling experience, the operator shall have the option of either running surface casing as provided in section 554.1(b) of this Part or of cementing the production casing from below the deepest potable fresh water level to the surface. In areas where the subsurface formations and pressures to be encountered are unknown or uncertain, surface casing shall be run as provided in section 554.1(b) of this Part.

6 NYCRR § 554.1(b) does not provide any specific direction on the type or amount of surface casing to be installed; it just says:

Pollution of the land and/or of surface or ground freshwater resulting from exploration or drilling is prohibited.

Nor does 6 NYCRR § 554.4(a) provide any specific direction on the type or amount of surface casing to be installed, other than to say that it must be set below *the deepest potable fresh water level,* but the minimum depth that the casing must be set below the deepest freshwater located is not specified.

Recommendation No. 10: 6 NYCRR § 554.1(d) and 6 NYCRR § 554.4(a) should be combined or at least be consistent to require the surface casing setting depth to be at least 100' below protected groundwater.

NYCRR does not provide the operator with instructions on how to determine protected groundwater depth. The RDSGEIS explains that the depth of potable freshwater in NYS is typically 850' deep, but this depth will vary across the state. Using the 850' benchmark may not sufficiently protect all groundwater covered under the Safe Drinking Water Act. NYCRR should be revised to provide instructions to the operator on how to estimate protected water depth in drilling applications and well construction designs. NYCRR should require that depth be confirmed before setting surface casing.

Recommendation No. 11: NYCRR should require the protected groundwater depth be estimated in the drilling application to aid in well construction design. NYCRR should require the protected water depth be verified with a resistivity log or other sampling method during drilling. If the protected water depth is deeper than estimated, an additional string of intermediate casing should be required. Additionally, the NYCRR needs to be clear on whether its purpose is to protect potable freshwater only, or a broader definition of protected groundwater, which would result in surface casing being set deeper.

6 NYCRR § 554.4(b) correctly requires: cement be placed by the pump and plug or displacement methods; cement be placed in the entire annulus; and a wait on cement time before further drilling. However, 6 NYCRR § 554.4(b) does not include the best practices listed in the permit conditions (Appendices 8 and 9). Additionally, many of the best practices included in Appendix 10 for HVHF wells should be included in regulations for all oil and gas wells.

Recommendation No. 12: 6 NYCRR § 554.4(b) should be revised to be consistent with the proposed Appendices 8 and 9 permit conditions. Also, the best practices listed in Appendix 10 for HVHF should apply to all oil and gas wells and be included in 6 NYCRR § 554.4(b).

Cable Tool Drilling Practices: 6 NYCRR § 554.3 includes requirements for cable tool drilling.

Recommendation No. 13: NYSDEC should verify whether cable tool drilling is still anticipated in NYS. If cable tool drilling is still allowed, 6 NYCRR § 554.3 should be revised to require these wells be constructed to the same quality standards as wells drilled with rotary drilling equipment.

Newly proposed surface casing regulations for HVHF wells at 6 NYCRR § 560.6(c)(10) require casing be run in accordance with the "department's casing and cementing requirements." Presumably this refers to the requirements set out in the RDSGEIS at Appendix 8, but this needs to be clarified. All surface casing requirements for HVHF operations should be codified in NYCRR.

A number of new requirements proposed at 6 NYCRR § 560.6(c)(10) should be applied to all wells in NYS, not just those that will undergo a HVHF treatment. 6 NYCRR § 560.6(c)(10) proposes to add these requirements only to HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*

(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and

(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.

(11) The surface casing must be run and cemented as soon as practicable after the hole has been adequately circulated and conditioned.

The zone of critical cement (e.g. cement placed at bottom of surface casing, typically bottom 300-500') should achieve a 72-hour compressive strength standard of 1,200 psi and the free water separation for the cement should be no more than 6 ml per 250 ml of cement. For example, this requirement is found in the Pennsylvania surface casing code (25 PaCode § 78.85 (b))

An analysis of the proposed Appendices 8, 9, and 10 permit condition requirements and inconsistencies, with comparisons to NYCRR, is provided in table format as Appendix A. Recommendations for improving requirements and addressing inconsistencies are listed in the table.

Recommendation No. 14: The recommendations listed in the Surface Casing Analysis Table (Appendix A to this report) should be considered for the SGEIS and the NYCRR, including:

Surface Casing Setting Depth: NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.

Protected Water Depth Verification: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.

Shallow Gas Hazards: If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

Cement Type: The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

Casing Quality: New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.

Cement Setting Time: Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.

NYS Inspectors: Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

Cement QA/QC: Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.

Formation Integrity Test: It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

BOP Installation: The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[39]

[39] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

7. Intermediate Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional intermediate casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on intermediate casing and the technical basis for HCLCC's recommendations.

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. A drilling engineer may set hundreds or thousands of feet of intermediate casing to: isolate unstable hole sections (to prevent collapse); isolate high or low pressure zones; isolate geologic "thief" zones prone to robbing mud from the well bore (lost circulation); put gas or saltwater zones behind pipe before drilling into the production zone; or provide additional wellbore structure.

Intermediate casing is set prior to drilling through the hydrocarbon bearing zone, and may be cemented behind the entire casing string from the top of the well to the bottom of the casing shoe, depending on intermediate casing depth. Intermediate casing provides an additional protective barrier across to prevent contamination of protected groundwater zones.

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for intermediate casing. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. NYSDEC proposed a number of substantial improvements in the intermediate casing requirements. The most notable improvement to the RDSGEIS mitigation and the NYCRR is that intermediate casing will be required in wells that undergo HVHF treatments to provide an additional protective layer of casing and cementing in the well. The RDSGEIS and the NYCRR requires intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools.

However, the remaining area for improvement in the NYCRR is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing. The proposed NYCRR is silent on the intermediate casing and cementing standards for wells that will not undergo HVHF treatment. NYS should provide instruction on intermediate casing standards for all wells that require it.

There are a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new NYCRR Part 560 (drilling practices for HVHF wells).

Recommendation No. 15: The NYCRR should be revised to establish intermediate casing and cementing standards for all wells at NYCRR Part 554 (drilling practices for all oil and gas wells).

This section reviews the proposed changes to intermediate casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS recommends that intermediate casing be required in wells that undergo HVHF treatments, to provide an additional protective layer of casing and cementing in the well. The 2011 RDSGEIS recommends that intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools. This is an excellent recommendation. The 2011 RDSGEIS states:

> *Current casing and cementing practices attached as conditions to all oil and gas well drilling permits state that intermediate casing string(s) and cementing requirements will be reviewed and approved by the Department on an individual well basis.* ***The Department proposes to require, via permit condition and/or regulation, that for high-volume hydraulic fracturing the installation of intermediate casing in all wells covered under the SGEIS would be required****. However, the Department may grant an exception to the intermediate casing requirement when technically justified [emphasis added].*[40]
>
> *The current dSGEIS proposes to require in most cases fully cemented intermediate casing, with the setting depths of both surface and intermediate casing determined by site-specific conditions*[41]
>
> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool; and*[42]
>
> *Fully cemented intermediate casing would be required unless supporting site-specific documentation to waive the requirement is presented. This directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[43]
>
> *Depending on the depth of the well and local geologic conditions, there may be one or more intermediate casing string.*[44]
>
> *Use of centralizers to ensure that the cement sheath surrounds the casing strings, including the first joint of surface and intermediate casings.*[45]

The 2011 RDSGEIS proposes a waiver process to exclude intermediate casing under some circumstances:

> *A request to waive the intermediate casing requirement would need to be made in writing with supporting documentation showing that environmental protection and public safety would not be compromised by omission of the intermediate string. An example of circumstances that may warrant consideration of the omission of the intermediate string and granting of the waiver could include: 1) deep set surface casing, 2) relatively shallow total depth of well and 3) absence of fluid and gas in the section between the surface casing and target interval. Such intermediate casing waiver request may also be supported by the inclusion of information on the subsurface and geologic conditions from offsetting wells, if available.*[46]

[40] 2011 NYSDEC, RDSGEIS, Page 7-52.
[41] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.
[42] 2011 NYSDEC, RDSGEIS, Page 1-12.
[43] 2011 NYSDEC, RDSGEIS, Page 1-12.
[44] 2011 NYSDEC, RDSGEIS, Page 5-92.
[45] 2011 NYSDEC, RDSGEIS, Page 7-42.
[46] 2011 NYSDEC, RDSGEIS, Page 7-52.

The proposed waiver process conflicts with the stated intent of requiring intermediate casing for HVHF wells. The RDSGEIS states that the reason intermediate casing is required for a HVHF well is because it:

> *...directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[47]

As proposed, NYSDEC would consider a wavier if the surface casing is set "deep" or if the well is "shallow"; however, these depths are not defined. The RDSGEIS does not explain how the use of deep-set surface casing or shallow surface casing provides the same protection to aquifers as installing a second string of intermediate casing and cement.

Additionally, as proposed, NYSDEC would consider a wavier if there is an "*absence of fluid and gas in the section between the surface casing and target interval.*[48]" This requirement is incongruous, because there will always be some type of fluid in the formation between the surface casing and target interval; therefore, the conditions for this waiver to occur would never be realized.

Recommendation No. 16: The SGEIS and NYCRR should be revised to remove the waiver provisions for intermediate casing on HVHF wells, or the SGEIS and NYCRR should be revised to include technical justifications, rationale and thresholds for proposed waivers.

The 2011 RDSGEIS requires that intermediate casing be cemented and evaluated for quality as follows:

> *Intermediate casing would be cemented to the surface and cementing would be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess would suffice.*[49]
>
> *The operator would run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing and the production casing. The quality and effectiveness of the cement job would be evaluated using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of API Guidance Document HF1 (First Edition, October 2009). Remedial cementing would be required if the cement bond is not adequate to drill ahead and isolate hydraulic fracturing operations, respectively.*[50]

The requirements for intermediate casing are listed in Appendices 8, 9, and 10 of the RDSGEIS.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires intermediate casing be set only in certain circumstances.

> *Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.*[51]

[47] 2011 NYSDEC, RDSGEIS, Page 1-12.

[48] 2011 NYSDEC, RDSGEIS, Page 7-52.

[49] 2011 NYSDEC, RDSGEIS, Page 7-53.

[50] 2011 NYSDEC, RDSGEIS, Page 7-54.

[51] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers requires intermediate casing be set:

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.*[52]

The main problem with the conditions of Appendices 8 and 9 is that there is no specific guidance for intermediate casing and cementing, if the intermediate casing string is required as part of the well construction design.

Recommendation No. 17: The SGEIS (Appendices 8 and 9) and NYCRR should be revised to provide specific intermediate casing and cementing requirements, as explained further in Appendix B.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional intermediate casing requirements.

The 2011 RDSGEIS Appendix 10 requires intermediate casing be set, unless a waiver is granted:

> *Intermediate casing must be installed in the well. The setting depth and design of the casing must consider all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the Department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may serve to form the basis for the Department waiving the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*[53]

The 2011 RDSGEIS Appendix 10 requires intermediate casing be completely cemented and the department be notified of cementing operations:

> *This office must be notified _____ hours prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess will suffice. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[54]

The 2011 RDSGEIS Appendix 10 requires a cement bond evaluation log:

[52] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[53] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[54] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).*[55]

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
>
> *b) casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
>
> *c) at least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
>
> *d) cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[56]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of a spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement; and*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus...*[57]

[55] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[56] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[57] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> > *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
> >
> > *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[58]

Appendix 10 requires records be kept as follows:

> *i) A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.* [59]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix B. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 do not include specific requirements for intermediate casing, when intermediate casing is part of the well construction design.

A new section of regulations at 6 NYCRR § 560.6(c)(13, 14 and 15) proposes to add intermediate casing requirements for HVHF wells:

> *(13) Intermediate casing must be installed in the well. The setting depth and design of the casing must be determined by taking into account all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may be considered by the department upon a request for a waiver of the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*

[58] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[59] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

(14) As specified on a permit to drill, deepen, plug back and convert, the department must be notified prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25 percent excess cement unless caliper logs are run, in which case 10 percent excess will suffice.

(15) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the intermediate casing. Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).

Additional intermediate casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells:

(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:

(i) all casings must be new and conform to industry standards specified in the permit to drill;

(ii) welded connections are prohibited;

(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;

(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;

(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;

(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;

(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and

(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued

pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to NYCRR is provided in table format in Appendix B. Recommendations for improving requirements are listed in the table.

Recommendation No. 18: The recommendations listed in the Intermediate Casing Analysis Table (Appendix B to this report) should be considered for the SGEIS and the NYCRR, including:

Waiver Provisions: It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.

Setting Depth: Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.

Protected Water Depth Verification: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.

Amount of Cement in Annulus: It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing cannot be fully cemented, most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.

Excess Cement: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the

current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the

well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

Pressure Testing: Casing and piping should be pressure tested.[60]

[60] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, Page 109.

8. Production Casing

Background: In 2009, HCLLC recommended NYCRR be revised to include additional production casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on production casing the technical basis for HCLCC's recommendations.

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone, or alternatively sets just above the hydrocarbon zone. Production casing can be run all the way from the surface of the well across the hydrocarbon zone (production casing string) or can be hung from the surface or intermediate casing at a point deeper in the well (production liner).

If production casing is set across the hydrocarbon-producing zone, it is called a "cased hole" completion. In this scenario, production casing is lowered into the hole and cemented in place. Explosives are then lowered inside the production casing (perforation guns) to perforate holes through the pipe/cement barrier to allow oil and/or gas to enter the wellbore. In some cases, a drilling engineer may elect not to set production casing. This is called an "open hole" completion.

NYSDEC recommends a full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place. This is a best practice for HVHF wells.

Production casing is used to isolate hydrocarbon zones and contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The 2011 RDSGEIS and proposed revisions to the NYCRR include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the NYCRR is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and NYCRR requires production casing be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. NYCRR also requires the cement placement and bond be verified by well logging tools. These requirements are best practice.

NYSDEC's proposed HVHF production casing design prevents pollution of protected groundwater by constraining the HVHF pressurized fluid treatment to the inside of the production casing string as it passes the protected groundwater zone. Additionally, behind the production casing string there are two additional layers of casing and cement installed as a barrier across protected waters (e.g. surface and intermediate casing).

This section reviews the proposed changes to production casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS requires that production casing be installed and fully cemented across the production zone in wells that undergo HVHF treatments. The 2011 RDSGEIS states:

> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool.* [61]
>
> *Anticipated Marcellus Shale fracturing pressures range from 5,000 pounds per square inch (psi) to 10,000 psi, so production casing with a greater internal yield pressure than the anticipated fracturing pressure must be installed.* [62]

The 2011 RDSGEIS Appendix 8: Appendix 8 NYSDEC's Casing and Cementing Practices includes the following production casing requirements for all wells.

12. *The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.*
13. *Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.*
14. *The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.*
15. *The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.*
16. *Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.*[63]

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers does not include any additional requirements for production casing.

[61] 2011 NYSDEC, RDSGEIS, Page 1-12.

[62] 2011 NYSDEC, RDSGEIS, Page 5-92.

[63] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2-3.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional production casing requirements.

The 2011 RDSGEIS Appendix 10 requires production casing run the entire length of the wellbore, which is an excellent recommendation. Appendix 10 also requires production casing be tied into intermediate casing with at least 500' of cement:

> *36) Production casing must be run to the surface. This office must be notified _____ hours prior to production casing cementing operations. If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[64]

Appendix 10 requires a cement bond evaluation log, which is another excellent recommendation:

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*[65]

However, Appendix 10 includes a waiver provision that would exempt an operator from installing production casing cement as described above. This waiver provision is based solely on whether oil and gas might migrate from one pool or stratum to another. It does not address any of the other reasons why production casing cementing is important and required by NYSDEC in HVHF wells.

> *Any request to waive any of the preceding cementing requirements must be made in writing with supporting documentation and is subject to the Department's approval.*
>
> *The Department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will be prevented. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[66]

Recommendation No. 19: The production casing cementing waiver should be removed for HVHF wells, or NYSDEC should provide more technical justification and rationale for the waiver. NYSDEC should show how environmental protection and safety objectives can be achieved to the same level with the waiver as without it.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

[64] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[65] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[66] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:

e) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;

f) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);

g) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);

h) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…[67]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

h) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…[68]

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

h) After the cement is pumped, the operator must wait on cement (WOC):

1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and

2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.[69]

[67] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[68] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[69] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 requires records be kept as follows:

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[70]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix C. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 include requirements for production casing:

> *If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing. In such instance, operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.*[71]

A new section of regulations at 6 NYCRR § 560.6(c)(16) proposes to add production casing requirements for HVHF wells.

> *(16) Production casing must be run to the surface. If installation of the intermediate casing is waived by the department, then production casing must be fully cemented to surface.* ***If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 300 feet of cement measured using True Vertical Depth****. Any request to waive any of the cementing requirements of this paragraph must be made in writing with supporting documentation and must be approved by the department. The department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will otherwise be prevented [emphasis added].*

The proposed regulations at 6 NYCRR § 560.6(c)(16) are inconsistent with the Appendix 10 requirement to cement the production casing with a 500' overlap into the intermediate casing.

> *If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[72]

[70] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[71] 6 NYCRR V.B. §554.4(d)

[72] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

Recommendation No. 20: A production casing 500' cement overlap into the intermediate casing is more protective; 6 NYCRR § 560.6(c)(16) should be revised to match Appendix 10.

A new section of regulations at 6 NYCRR § 560.6(c)(17) requires production casing cement be verified for HVHF wells:

> *(17) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the production casing. Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*

Additional production casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*
>
> *(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and*
>
> *(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.*

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to the NYCRR is provided in table format in Appendix C. Recommendations for improving requirements are listed in the table.

Recommendation No. 21: The recommendations listed in the Production Casing Analysis Table (Appendix C to this report) should be considered for the SGEIS and the NYCRR, including:

Casing Design: For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging, and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.

Centralizers: Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where production casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[73]

[73] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

9. Permanent Wellbore Plugging & Abandonment Requirements

Background: In 2009, HCLLC recommended that NYSDEC establish specific criteria to determine when a well must be permanently plugged and abandoned (P&A'd) and recommended improvements in NYS' well plugging regulations, incorporating best technology and practices.

Several terms are used to describe the condition of oil and gas wells that are not active hydrocarbon producers.

- Temporary Abandonment. This term is used to describe a well that may be temporarily suspended as a production well. The well may be shut-in awaiting repairs, a stimulation treatment, workover (e.g. drilling into a new zone) or a decision to finally P&A the well. A reasonable amount time should be afforded to the operator to complete the well work, or to decide when to P&A the well; however, a well should not be temporarily abandoned for a long period of time, because it poses a risk to the environment, especially if the well is known to have a leak or mechanical malfunction. Leaking or malfunctioning wells should be repaired in a timely manner or the well should be permanently P&A'd.

  In 2003, ICF Consulting produced a report for the New York State Energy Research and Development Authority (NYSERDA) that concluded NYS had 5,900 shut-in or temporarily abandoned wells, 39% of the 15,000 known wells.[74] ICF concluded that more than half the 5,900 wells have been "temporarily" abandoned for more than nine years. ICF concluded that:

  > *NYS is one of the few oil and gas producing states that have no specific regulatory provisions for long-term shut-in wells (more than two years). New York's current regulations allow an initial shut in period of one-year and an extension of up to one year, renewable for additional successive periods…*[75]

  ICF concluded that while operators are required to contact NYS to justify temporary abandonment extensions beyond one year, NYS' lack of resources to oversee the program has resulted in many wells remaining idle and not properly P&A'd for years:

  > *The practical effect is that New York's idle well regulation cannot be adequately enforced due to constraints on manpower and other agency resources, and as a result, New York has a defacto long-term inactive well program. For example New York has approximately 1,379 gas wells and 1440 oil wells with either inactive or unknown status that have no reported production since 1992.* [76]

- Permanent Abandonment. A well that is no longer needed to produce hydrocarbons should be plugged (e.g. cement barriers installed, failed casing removed, mechanical plugs set), surface equipment removed (e.g. wellhead and piping), and permanently abandoned. Operators typically do not monitor well condition once a P&A'd job is complete and approved by an agency.

[74] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 1. A final version of this report could not be located on the world-wide web.

[75] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 5.

[76] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 36.

- Improperly Abandoned Well. This term describes a well that was P&A'd, but was done so in a manner where the well still poses a risk to the environment (e.g. insufficient barriers or cement used to seal the well). Because operators typically do not monitor the condition of P&A'd wells, improperly abandoned wells often go un-resolved.

  The problem of improperly abandoned wells in NYS may be a significant issue, because NYS' P&A regulations currently only require 15' cement plugs, which NYSDEC now recognizes as deficient. Therefore, most wells in the state were not P&A'd using a quality standard that would be considered best technology and best practice today.

- Orphaned Well. This term describes a well that was orphaned by the well operator (e.g. insolvent, absentee, or non-responsive well owners) and the well was not P&A'd. Because, by definition, an "orphaned well" does not have an operator to monitor its condition, permanent abandonment of these wells typically becomes a government or property owner responsibility. Given limited agency resources, the magnitude of the environmental hazard posed by any particular orphaned well often is unknown. Unless government or property owners make it a priority to fund well monitoring or plug the well, the potential environmental impacts of orphaned wells cannot be ascertained.

In 2003, ICF Consulting, further examined 4,140 of the long-term inactive wells in NYS and concluded that:

- 546 of the 4,140 wells (13%) were drilled and completed before 1924 (over 87 years old now);
- 1,568 of the 4,140 wells (38%) were drilled and completed from 1924-1964 (at least 47 years old now, and possibly up to 87 years old); and
- 2,026 of the 4,140 wells (49%) had no information on the date of complete or condition.[77]

Therefore, there are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned).

NYS' 2009 Annual Oil and Gas Report[78] shows improperly abandoned and orphaned wells continue to be a significant problem in NYS. NYSDEC reports:

> ***Abandoned, unreported and inactive wells continued to be a problem. In 2009 a total of 450 operators reported 3,043 wells with zero production. This is in addition to over 4,100 orphaned and inactive wells in the Department's records****. Enforcement actions have reduced the number of unreported wells yet some operators refused to file their annual reports. The operators that remained out of compliance have been referred to the Office of General Counsel for additional enforcement actions.[emphasis added]*
>
> *DEC has at least partial records on 40,000 wells, but estimates that over 75,000 oil and gas wells have been drilled in the State since the 1820s.* ***Most of the wells date from before New York established a regulatory program****.* ***Many of these old wells were never properly plugged or were plugged using older techniques that were less reliable and long-lasting than modern methods.*** *[emphasis added]*

[77] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 32.

[78] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009, pp. 22-23.

> *Every year while conducting scheduled inspections or investigating complaints, DEC staff discover more abandoned wells. Extensive courthouse research is often required to identify a well's previous owners. Many of these cases take several years to resolve as DEC pursues legal action against the responsible parties.*
>
> *New York has an Oil and Gas Account which was created to plug problem abandoned wells. It is funded by a $100 per well permit fee; at the end of 2009 the balance was $208,806. DEC has over 500 wells on its priority plugging list. Since* ***the funds are insufficient to plug all the priority wells****, DEC continues to pursue other mechanisms to plug abandoned wells [emphasis added].*

Well construction standards, techniques and technology have improved over time, and it is reasonable to assume that most of these long-term idle wells were not constructed to today's standards, have been subject to mechanical wear and corrosion, and warrant proper abandonment to mitigate risk to protected groundwater resources.

To compound problems, many wells that have not been properly abandoned do not have financial security (e.g. bonds) in place to fund P&A work. ICF reported that, in 2003, NYS had more than 3,500 wells that needed to be P&A'd, but there was no financial security in place (e.g. wells that were grandfathered from NYS bonding requirements). Additionally, ICF reported that 675 of the existing oil and gas wells in NYS have operators that do not comply with the current bonding requirements, and numerous operators that might comply with the existing bonding requirements have plugging liability in amounts that exceed NYS' current bonding requirements, which are too low and do not keep pace with the actual costs of P&A'ing wells today.[79]

The number of temporarily abandoned wells, improperly abandoned wells, and orphaned wells in NYS is a significant issue as shale gas resources are developed, because these old wells could provide a vertical conduit for pollutants to reach protected aquifers. Shale gas wells drilled and fracture stimulated nearby a temporarily abandoned, improperly abandoned, or orphaned well pose a risk. For example, a HVHF treatment can propagate a fracture that, depending on geology, HVHF design, and well depths, could pose a risk of intersection with a nearby well (active producer, abandoned or orphaned well).

Temporarily abandoned wells, improperly abandoned wells, and orphaned wells all pose a risk to the environment. Wellbore infrastructure can corrode and erode, failing over time and creating a potential pollutant pathway for hydrocarbons to move vertically through failed casing or cement to groundwater resources. These wells can either leak gas on their own or provide a vertical pollutant pathway to groundwater resources that can be activated by new well activity nearby.

In 2009, HCLLC recommended that temporary abandonment be limited to no longer than a one-year period, with a wellbore integrity monitoring requirement to ensure that the well is not leaking during temporary abandonment, and a requirement to permanently abandon the well after it is idle for more than a year. HCLLC recommended that NYSDEC carefully examine idle wells that have not been properly P&A'd and that are in close proximity to drinking water sources and in areas under consideration for new HVHF treatments, and require those wells to be P&A'd as a high priority and before shale gas drilling operations commence in those areas.

[79] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 35-36.

A report documenting specific cases of well pollution caused by NYS' improperly abandoned wells or orphaned wells could not be located; however, neighboring Pennsylvania has completed an analysis of this problem, and it sheds light on the problems NYS may encounter.

Pollution caused by improperly abandoned wells in Pennsylvania is documented in a 2009 report prepared by Pennsylvania Department of Environmental Protection (PADEP). The PADEP report lists 27 cases where improperly abandoned wells have been the source of groundwater contamination.[80] In some of the 27 cases the wells were abandoned according to the standard practices of the time, but now leak and need to be re-abandoned using improved materials and techniques. Some of the cases cited by PADEP include very old well construction techniques, for example, surface casing made out of wood that has rotted away, and wells with no surface casing or cement installed at all. These wells have provided a conduit for gas and other pollutants to reach groundwater through damaged or worn casing, poorly installed cement, or more directly where casing or cement was not initially installed.

PADEP also identified wells that need to be P&A'd, but have not yet been addressed due to the lack of a responsible party and/or on account of PADEP resource limitations.[81]

There were three cases cited by PADEP where fracture stimulations in an operating well communicated with a nearby abandoned well, causing a gas leak in the abandoned well.[82] PADEP's study highlighted the importance of locating orphaned and improperly abandoned wells near new oil and gas developments, and study shows the importance of properly abandoning wells before new development proceeds.

A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. The study found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[83] Clearly, the higher incidence rate of methane contamination in drinking water wells in shale gas extraction areas is not a coincidence, but is an indicator of shale gas drilling and completion operations mobilizing gas from the shale gas reservoir into protected aquifers. One of the most likely pathways for leaking of gas mobilized by HVHF is a nearby existing well that either was improperly constructed or improperly plugged. Given their failed cement, corroded casing, or lack of casing or cement, such improperly abandoned wells present vertical pathways to aquifers and drinking water resources.

Mechanical failure, human error, and engineering design flaws do occur in the construction and operation of wells. Indeed, groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

[80] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[81] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009. Cases include: Independent Valley News Migration, Allegheny County – SWRO – March 2009; Versailles Migration, Versailles, Allegheny County – SWRO – 2007 through 2008; Childers Migration, Washington County – SWRO – June 2005; Groshek Migration, Keating Twp., McKean County – NWRO – 2008; and Skinner Migration, Columbus Twp., Warren County – NWRO.

[82] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[83] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane Contamination of Drinking Water Accompanying Gas Well Drilling and Hydraulic Fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, p.2.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[84] PADEP inspectors "…discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County."[85] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[86]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[87]

In May 2011, PADEP determined that improper well casing and cementing in Chesapeake Energy Corporation's shallower wells allowed migration into groundwater and caused contaminated 16 families' drinking water supplies in Bradford County.[88]

Pennsylvania has found that significant planning and research is needed to identify orphaned and improperly abandoned wells before drilling nearby wells. At a 2009 Stray Gas Workshop in Pennsylvania, Garrett Velosi, from the National Energy Technology Laboratory, pointed out that one of the main problems with stray gas leaks from abandoned wells is verifying the location of improperly abandoned wells. Records on older wells are often limited or non-existent. Mr. Velosi presented methods for locating unmarked abandoned wells. They include the use of historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).[89]

In January 2011, NYS' consultant Alpha Geoscience agreed that timely well plugging and abandonment requirements are important; however, it recommended that establishing "a specific timeline for plugging and abandonment is neither practical nor necessary."[90] Alpha Geoscience did not examine the large backlog of improperly abandoned wells in NYS or the risk of groundwater contamination from improperly abandoned wells located within the radius of influence of new gas wells and HVHF operations. Alpha Geoscience did not recommend any improved P&A procedures, despite NYCRR's outdated requirements. 6 NYCRR § 555.5 requires only 15' cement plugs, as compared to Texas, Alaska, and Pennsylvania regulations that require a series of 50'-200' cement plugs at various locations within the wellbore.

[84] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[85] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[86] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[87] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

[88] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[89] Veloski, G., National Energy Technology Laboratory, Methods for Locating Wells in Urban Areas – A Summary of Case Studies, Pennsylvania Stray Gas Workshop, November 2009.

[90] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011

HCLLC disagrees with Alpha Geoscience's recommendation to NYSDEC. Alpha Geoscience's recommendation also conflicts with prior advice from ICF to NYSERDA. HCLLC finds that it is practical and necessary to properly abandon wells on a reasonable timeline, and recommends that NYCRR be improved to include best practices and techniques for permanent wellbore abandonment.

2011 RDSGEIS: The 2011 RDSGEIS document is inconsistent on its recommendations for P&A'ing wells. In Chapter 5, NYSDEC concludes that no improvements are needed in the NYCRR regulations, but proposes changes to improve the regulations at 6 NYCRR § 555.5. In Chapter 6, NYSDEC concludes that it is not possible for HVHF treatments to intersect improperly abandoned wells; yet, in Chapter 7 NYSDEC proposed mitigation to address this very risk. These inconsistencies are further explained below, with recommendations for resolving them.

Chapter 5 of the RDSGEIS concludes that well plugging procedures and requirements in the existing NYCRR (described in the 1992 GEIS) are sufficient to address the risk of improperly abandoned wells. The 2011 RDSGEIS states:

> *As described in the 1992 GEIS, 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 continue 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 [emphasis added].*[91]
>
> *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 (i.e., 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. Removal of all surface equipment and full site restoration are required after the well is plugged.*
>
> *The plugging requirements summarized above are described in detail in Chapter 11 of the 1992 GEIS and are enforced as conditions on plugging permits. Issuance of plugging permits is classified as a Type II action under SEQRA. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action.* ***Horizontal drilling and high-volume hydraulic fracturing do not necessitate any new or different methods for well plugging that require further SEQRA review*** *[emphasis added].*[92]

[91] 2011 NYSDEC, RDSGEIS, Page 5-143.

[92] 2011 NYSDEC, RDSGEIS, Page 5-144.

While NYSDEC agrees that proper well P&A is critical to the protection of groundwater, surface water, and soil, it concludes that horizontal drilling and HVHF shale gas wells do not require any new or different P&A methods. However, this conclusion is inconsistent with NYSDEC's proposed revisions to the P&A procedures at 6 NYCRR § 555.5, this proposal suggests that the existing regulations do not represent best practices.

Recommendation No. 22: The SGEIS should be revised to state that the existing P&A procedures at 6 NYCRR § 555.5 were determined to be outdated and not best practice and that NYSDEC has proposed revisions. The basis for NYSDEC's proposed revisions should be justified in the SGEIS, and include a review of other states' best practices for P&A.

Chapter 5 of the RDSGEIS does not address: (1) whether NYS has a backlog of wells requiring P&A in close proximity to drinking water sources; (2) whether NYS has a backlog of wells requiring P&A in close proximity to areas under consideration for HVHF treatments; (3) whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and (4) whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

Recommendation No. 23: The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

For example, maps showing the location and depth of NYS' temporarily abandoned, improperly abandoned, or orphaned wells could not be located; however, this data is needed to ensure safe development of shale gas resources. The RDSGEIS proposes that operators identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[93]; however, ICF's 2003 report to NYSERDA points out that there are a large number of old wells in NYS where location or well condition data is not available in NYSDEC's Oil & Gas database. If NYSDEC has improved the Oil & Gas database to accurately document all existing wells this information should be included in the SGEIS and maps of the wells should be made available.

Recommendation No. 24: The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

In Chapter 6 of the RDSGEIS, NYSDEC discounts the risks of new HVHF shale gas wells communicating with nearby abandoned wells. NYSDEC relies on its consultant's (ICF) analysis that concludes it is not possible for HVHF treatments to intersect with improperly abandoned wells.[94] Yet, in Chapter 7, NYSDEC recommends precautionary measures to be taken by operators to ensure that wells

[93] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[94] 2011 NYSDEC, RDSGEIS, Page 6-52.

near HVHF operations are properly P&A'd to prevent freshwater contamination. The RDSGEIS is internally inconsistent on this point and the two diametrically opposed conclusions need reconciliation.

Recommendation No. 25: Chapter 6 of the SGEIS should be revised to be consistent with and support the Chapter 7 recommendation for HVHF operators to ensure all nearby wells are properly P&A'd before HVHF operations are conducted to mitigate the risk of HVHF treatments intersecting improperly abandoned wells. This requirement should also be codified in NYCRR.

In 2009 HCLLC recommended that preventative measures be taken to identify and properly abandon existing wells before proceeding with nearby shale gas drilling and HVHF operations. NYSDEC responded favorably to this recommendation by proposing that the operator identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[95] and by proposing that any improperly abandoned wells be plugged within that one-mile radius.[96] While NYS' recommendation is a step in the right direction, additional analysis is needed to justify the one-mile radius selected.

The RDSGEIS does not provide data on the maximum horizontal fracture propagation length that could occur at NYS' proposed 2000' depth cut-off. The RDSGEIS assumes the maximum horizontal well length will be 4000'. However, as highlighted in other sections of this report, current horizontal drilling technology allows for wells to be drilled substantially longer than 4000'. Fractures induced along that horizontal wellbore section can propagate several thousand feet from the well, depending on fracture treatment design parameters. Therefore, the wellbore length and the maximum fracture length combined could result in a radius of influence of more than one mile (5,280').

Recommendation No. 26: The SGEIS should provide technical justification for selecting a one-mile wellbore intersection radius and should explain the maximum horizontal drilling length and horizontal fracture length that corresponds with the proposed one-mile radius. This will be especially important for shallower wells where fractures tend to propagate on a horizontal plane, and where there will be a large number of potential shallow well intersection possibilities.

The SGEIS should examine the potential for longer wellbores and large fracture influence zones to occur now or in the future, and a wellbore intersection radius that corresponds to the largest areas of influence that are reasonably foreseeable should be included in the SGEIS as a mitigation measure and be codified in the NYCRR. Alternatively, if NYSDEC selects a one mile radius, the SGEIS should limit drilling length and horizontal fracture length in the SGEIS as a mitigation measure and in the NYCRR to ensure that the radius of influence does not extend beyond the one-mile impact area proposed.

The RDSGEIS proposes, in Table 11.1, that operators identify and plug wells within a one-mile radius, but this requirement is not translated into a permit condition or codified in NYCRR. Table 11.1 proposes:

> *Operators must identify and characterize any existing wells within the spacing unit and within one mile of proposed well and* ***plug and abandon any well which is open to the target formation or is otherwise and immediate threat to the environment*** *[emphasis added].*[97]

[95] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[96] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

[97] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

Appendix 6, PROPOSED Environmental Assessment Form Addendum requires the operator to complete the one-mile radius of investigation, yet, there is no requirement in Appendix 10 or in the NYCRR requiring the offset wells to be plugged by the HVHF operator if needed.

In direct contrast to the conclusions reached in Chapter 6, Chapter 7 of the RDSGEIS acknowledges the potential risk of HVHF wells intersecting improperly abandoned wells and proposes a process to address these risks:

> ***To ensure that abandoned wells do not provide a conduit for contamination of fresh water aquifers, the Department proposes to require that the operator consult the Department's Oil and Gas database as well as property owners and tenants in the proposed spacing unit to determine whether any abandoned wells are present. If (1) the operator has property access rights, (2) the well is accessible, and (3) it is reasonable to believe based on available records and history of drilling in the area that the well's total depth may be as deep or deeper than the target formation for high-volume hydraulic fracturing, then the Department would require the operator to enter and evaluate the well, and properly plug it prior to high-volume hydraulic fracturing if the evaluation shows the well is open to the target formation or is otherwise an immediate threat to the environment.*** *If any abandoned well is under the operator's control as owner or lessee of the pertinent mineral rights, then the operator is required to comply with the Department's existing regulations regarding shut-in or temporary abandonment if good cause exists to leave the well unplugged. This would require a demonstration that the well is in satisfactory condition to not pose a threat to the environment, including during nearby high-volume hydraulic fracturing, and a demonstrated intent to complete and/or produce the well within the time frames provided by existing regulations [emphasis added].*[98]

While Chapter 7 correctly acknowledges the need for P&A procedure improvement and review of nearby abandoned wells before HVHF treatments, NYSDEC incongruously proposes to limit P&A due diligence to: 1) wells that are within the HVHF well operator's control and 2) wells that are "accessible." This approach discounts the risks posed by improperly abandoned wells that are owned by another operator, orphaned, or difficult to access.

The inconsistency in P&A improvement recommendations persists in the Appendix 10 HVHF Permit Conditions where the recommended improvements in Chapter 7 are not included. The Chapter 7 recommendations are not included in the revised NYCRR either.

[98] 2011 NYSDEC, RDSGEIS, Page 7-58.

Recommendation No. 27: If a well was not properly P&A'd to current standards, the operator should be required to work with the well owner or take the initiative itself to ensure the well is properly P&A'd before new drilling begins and before a nearby HVHF treatment occurs. Approval of a HVHF well application should be conditioned on verification that any necessary P&A work is complete. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC should consider requiring operators to use a variety of proven methods to locate unmarked, abandoned wells, including: historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).

The proposed mitigation measure, requiring improperly abandoned or orphaned wells to be plugged prior to a HVHF treatment, should be included in Appendix 10, of the SGEIS and codified in the NYCRR.

Additionally, NYSDEC should request ICF to further examine additional technical and scientific questions that were not addressed in its analysis.

Foremost, ICF's report does not indicate that ICF evaluated the difference in reservoir pressure near a new shale gas wellbore, drilled into an un-depleted higher pressure gas reservoir, as compared to the lower reservoir pressure in the drainage radius around a well that previously served or is currently serving as a production well. The reservoir pressure in the drainage radius around a production well will be substantially lower creating a pressure sink around that well. By the laws of physics, gas and fluid will flow from higher pressure regimes to lower pressure regimes. Therefore, if a HVHF treatment intersects the drainage radius around a nearby pressure-depleted reservoir connected to an improperly abandoned well, the HVHF fluid and associated mobilized gas will continue to move towards the improperly abandoned well, not back to the new shale gas well as ICF suggests.

As explained in Chapter 10 of this report, industry data shows that HVHF treatments are propagating well beyond the shale zone into formations located above and sometimes below the shale, meaning that the HVHF treatment can potentially intersect the depleted well drainage area of a well that has produced from a zone above or below the shale.

However, ICF concludes that, once the HVHF treatment pressure ceases, all HVHF fluid will return to the shale gas well, and there is no possibility that HVHF fluid or associated mobilized gas will travel up an improperly abandoned well conduit. This conclusion is based on the assumption that the lowest pressure pathway for HVHF fluids injected into the formation is back to the shale gas well, but such assumption does not account for the possibility that a lower pressure regime at an abandoned or active well site could influence the flow of HVHF fluids and newly mobilized gas. It also discounts the possibility that other lower pressure intervals could be located above or below the shale zone that would preferentially accept HVHF fluids and gas mobilized during the treatment.

In these cases, HVHF fluids and gas would continue towards the improperly abandoned well and up the well conduit until pressure equilibrium is reached or into adjacent lower pressured reservoirs. This could result in HVHF fluids and associated gas that is mobilized during the HVHF treatment contaminating groundwater if an exposure pathway exists in the improperly abandoned well or from an adjacent lower pressure reservoir to a shallower protected water zone.

While it is true that HVHF fluids will flow back to the new shale gas well if such well presents the lowest pressure regime for fluid to flow to, this will not always be the case, as evidenced by the fact that not all the HVHF fluid returns to the well. The RDSGEIS states that:

> *Flowback water recoveries reported from horizontal Marcellus wells in the northern tier of Pennsylvania range between 9 and 35 percent of the fracturing fluid pumped. Flowback water volume, then, could be 216,000 gallons to 2.7 million gallons per well, based on a pumped fluid estimate of 2.4 million to 7.8 million gallons, as presented in Section 5.9.*[99]

Therefore, several million gallons of HVHF treatment fluid remain in the reservoir and will travel to the lowest pressure formation/regime present, including such lower pressure regimes present around nearby existing wells that have previously produced hydrocarbons. An out-of-zone HVHF, as described in Chapter 10 of this report could potentially connect with this lower pressure reservoir, if not properly designed and implemented.

Secondly, ICF's analysis did not examine the maximum horizontal distance a HVHF could travel, nor identify minimum safe separation distances between horizontal fractures and abandoned wells. Thus, ICF did not attempt, to compare the maximum HVHF length to the closest distance that an abandoned well may occur.

Instead, ICF's analysis assumes that the HVHF impact radius would always be less than the distance to a nearby well (which may not be true in all cases, and will depend on reservoir characteristics and job design). ICF concludes, without basis, that a fracture created by a HVHF would never intersect a nearby well, but does not establish the well spacing distance required for this to be true nor does it consider the fact that Marcellus Shale fractures (as shown in Chapter 10 of this report) do routinely propagate out of zone.

Additionally, the Chapter 6 conclusion that it is not possible for a HVHF treatment to intersect an improperly abandoned well is discordant with three cases cited in PADEP's 2009 Report that document situations in which fracture stimulations in operating wells communicated with nearby abandoned wells, causing gas leaks in the abandoned wells.[100] PADEP's cases confirm that fracture stimulations, if improperly designed and executed, can intersect improperly abandoned and orphaned wells.

Recommendation No. 28: The SGEIS and NYCRR should require HVHF well operators to identify previously drilled wells that may be located within the hydraulic radius of the new shale gas well that may be affected during a HVHF treatment. The operator should be required to estimate the maximum horizontal and vertical extent of the fracture length that will be propagated and ensure that there are no abandoned or improperly abandoned wells in that intersection radius. An additional safety factor should be applied in this analysis to account for uncertainty in fracture design and implementation, and the potential for the actual fracture length to be longer than estimated (e.g. a conservative analysis is needed).

The HVHF treatment size should be designed to ensure that it does not intersect with any abandoned or improperly abandoned wells, with an additional margin of safety.

[99] 2011 NYSDEC, RDSGEIS, Page 5-99.

[100] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

Any improperly abandoned wells nearby, and just outside, the intersection radius should be properly abandoned to current standards before new drilling begins and before the HVHF treatment occurs.

NYCRR Proposed Revisions: Despite the 2011 RDSGEIS conclusion that no new P&A requirements are needed, and NYSDEC's consultant's (Alpha Geoscience) recommendation that no improvements are necessary, NYSDEC proposed revisions to its existing well P&A requirements at 6 NYCRR § 555.5, Plugging Methods, Procedures and Reports:

(a) The plugging of a well shall be conducted in accordance with the following sequence of operations[:] ***. The Division at its discretion may require the tagging of all plugs and require casing and/or cement evaluation logs to be run to determine proper plugging procedures. The following are minimum requirements for plugging and the department may impose additional requirements****: [emphasis added]*

> *(1) The well bore, whether to remain cased or uncased, shall be filled with cement from total depth to at least [15] 50 feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity. Alternatively, a bridge topped with at least [15] 50 feet of cement shall be placed immediately above each formation from which the production of oil or gas has ever been obtained in the vicinity.*
>
> *(2) [If] For any casing [is to be] left in the ground, a cement plug of at least [15] 100 feet in length shall be placed [at the bottom of such section of casing] 50 feet inside and 50 feet outside of the casing shoe . Uncemented casing must be pulled as deep as practical with a 50-foot plug placed in and above the stub of the casing. If the uncemented casing is unable to be pulled the casing must be ripped or perforated 50 feet below the shoe of the next outer casing and a 100-foot plug placed across that shoe. A [similar] 50 foot plug shall be placed at [the top of such section of casing unless it shall extend to]the surface. [In the latter event, the casing shall be capped in any such manner as will prevent the migration of fluids and not interfere with normal soil cultivation.]*
>
> *(3) If casing extending below the deepest potable fresh water level shall not remain in the ground, a cement plug of at least [15] 50 feet in length shall be placed in the open hole at a position approximately 50 feet below the deepest potable fresh water level.*
>
> *(4) If the conductor casing or surface casing is drawn, a cement plug of at least [15] 50 feet in length shall be placed immediately below the point where the lower end of the conductor or surface casing shall previously have rested. The hole thereabove shall be filled with cement, sand or rock sediment or other suitable material in such a manner as well prevent erosion of the well bore area and not interfere with normal soil cultivation.*
>
> *(5) The interval between all plugs mentioned in paragraphs (1) through (4) of this subdivision shall be filled with [a heavy mud-laden] gelled fluid with a minimum density equal to 8.65 pounds per gallon with a 10 minute gel-shear strength of 15.3 to 23.5 pounds per hundred square feet or other department approved fluid.*

NYSDEC's proposed revisions are a step in the right direction. Overall, NYSDEC proposes to require longer cement plugs, weighted mud, and some additional QA/QC procedures, including tagging the cement plugs and possibly running cement evaluation logs.

NYSDEC's existing P&A regulations require short cement plugs (15'), which are woefully inadequate, compared to current best practices of installing a series of 50'-200' cement plugs within a wellbore, and removing corroded casings to isolate water resources. Unfortunately, this means that most of NYS'

abandoned wells, if plugged to NYCRR's existing standards, are not likely to provide adequate groundwater protection. To address this problem, the P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards.

Recommendation No. 29: P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards and this requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC's proposed increase to 50' cement plug length is an improvement; however, best practices used in other states such as Texas, Alaska, and Pennsylvania require longer cement plugs. NYSDEC should consider enhancing the regulations to require longer and additional cement barriers to ensure that hydrocarbons and freshwater are confined to their respective indigenous strata, and are prevented from migrating into other strata or to the surface. For example, while NYSDEC has proposed to revise the NYCRR to require a 50' cement barrier, Alaska requires double that protection at 100'.[101] Pennsylvania recently upgraded its P&A requirements from its previous 50' standard to plugs of 50'-100'.[102] Texas requires cement plugs ranging from 50'-200' at numerous locations in the well, and requires cement QA/QC procedures.[103] For example, Texas requires each cement plug to be a minimum of 200' in length and extend at least 100' below and 100' above the top of each hydrocarbon stratum and the base of the deepest protected water stratum, which is a substantial difference from NYS' current requirement for 15' plugs.

Recommendation No. 30: The SGEIS mitigation measures and NYCRR should be revised to clearly specify that:

Plugging a wellbore should be performed in a manner that ensures all hydrocarbons and freshwater are confined to their respective indigenous strata, and prevented from migrating into other strata or to the surface.

All hydrocarbon-bearing strata should be permanently sealed off by installing a cement barrier at least 100 feet below the base to at least 100 feet above the top of all hydrocarbon-bearing strata (200' plug).

The plugging of a well should include effective segregation of uncased and cased portions of the wellbore to prevent the vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to at least 100 feet above the casing shoe (200' plug).

The operator should be required to submit records to NYSDEC to demonstrate that the well is P&A'd in compliance with regulations.

NYSDEC should consider specifying the grade of cement required to plug the well. It should also consider requiring the use of gas blocking agents.

[101] 20 AAC 25.

[102] PA Code, § 78.91.

[103] 16 TAC Part 1, § 3.14.

Revisions to the NYCRR include some improved QA/QC procedures, but these revisions are loosely written and do not specify when QA/QC procedures will be mandatory. For example, it is best practice to tag all cement plugs to verify placement depth; this should not be an optional, discretionary procedure. Also, NYSDEC should specify under what circumstances a cement evaluation tool will be required.

Recommendation No. 31: The SGEIS mitigation measures and NYCRR should be revised to require cement quality standards, including the use of gas blocking cement. The SGEIS and NYCRR should require tagging of all cement plugs and provide instructions on when additional cement evaluation tools must be run.

10. HVHF Design and Monitoring

Background: In 2009, HCLLC recommended that NYSDEC revise its regulations to specify and require best technology and best practices for collecting data, and modeling, designing, implementing, and monitoring a fracture treatment, including:

(a) Collecting additional geophysical and reservoir data to support a reservoir simulation model;

(b) Developing a high-quality Marcellus Shale 3D reservoir model(s) to safely design HVHF treatments;

(c) HVHF modeling prior to each fracture treatment to ensure that the fracture is contained to the Marcellus Shale zone;

(d) Careful monitoring of the fracture treatment, including shutting the treatment down if data indicates casing leaks or out-of-zone fractures;

(e) Starting with smaller fracture treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience (e.g. 4,000' deep and 150' thick);[104]

(f) Using the experience gained with fracture testing on deeper sections of the Marcellus to design and implement larger treatment volumes over time (potentially allowing increasingly shallower and thinner intervals *only* if technical data supports the safety of this technique); and

(g) Documenting, reporting, and remediating fracture treatment failures to ensure drinking water protection.

In 2009, HCLLC recommended that fracture treatments be carefully monitored and shut down if pressure data indicates casing leaks. HCLLC noted the American Petroleum Institute recommends continuous and careful monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate, [105] and that fracture treatments should be immediately shutdown if abnormal pressures indicate a casing leak. The 2011 RDSGEIS now requires the operator to carefully monitor fracture treatments and shut down the treatment if data indicates casing leaks or out-of-zone fractures. This is an important improvement to the SGEIS.

Experts agree that Marcellus Shale gas production can be maximized by: 1) drilling long horizontal wells to increase the drainage area and 2) conducting hydraulic fracture treatments to improve permeability and access to trapped gas. However, successful, safe development requires hydraulic fracture treatments be properly designed and sized to remain <u>within</u> the shale zone. Fracture treatments that propagate <u>outside</u> the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport. There is extensive industry literature on the importance of hydraulic fracture design, modeling, and field verification to optimize fracture stimulation. Therefore, in 2009 HCLLC recommended that the DSGEIS be improved to provide additional technical and scientific data and require specific mitigation, ensuring that operators are designing jobs that will not fracture out-of-zone.

[104] Smaller, deeper fracture treatments could be used initially in NYS, the performance examined, the predictive model improved based on that data, and then fracture treatment size and proximity to protected waters and other wellbores could be modified, as confidence increases in the predictive ability of the model to ensure a safe and favorable result.

[105] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

Pollutant transport and pollutant toxicity issues are addressed in Dr. Tom Myers' and Dr. Glenn Miller's reports to NRDC on the 2009 DSGEIS and the 2011 RDSGEIS. HCLLC's recommendations center on what type of data, analysis, tools, and methods an engineer/operator should have in place and use to ensure that a fracture treatment can be contained within the Marcellus Shale zone.

In 2009, HCLLC observed that NYSDEC and/or operators had not provided sufficient data to demonstrate that a HVHF treatment can be contained to the Marcellus Shale. HCLLC pointed out that the 2009 DSGEIS did not require the operator to demonstrate that it is equipped with sufficient expertise, training, qualifications, and engineering tools to safely design, implement, and assess the performance of HVHF treatments. HCLLC recommended that NYSDEC consider operator qualifications.

HCLLC's recommendations on the 2009 DSGEIS explained that it is best practice in newly developed formations, such as the NYS Marcellus Shale, to build hydraulic fracture models. Fracture models are used by engineers to safely design fracture treatments. During actual fracture stimulation treatments, data are collected to verify model accuracy, and the model is continually refined to improve its predictive capability.

Because fracture treatments may be executed several thousand feet below the surface of the earth, and can only be indirectly observed, it is important for engineers to have a 3D model to guide design. While 3D modeling is not an exact science, the model provides an engineer with an estimating method for predicting both horizontal and vertical fracture length.

As further explained below, data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability.

In newly developed areas it is important to conduct initial HVHF treatments in the lowest risk zones, far below protected aquifers and with large horizontal offsets from existing wells. Until the predictive capability of site-specific models improves from the input of actual field data, larger buffer zones should be used. Absent hydraulic fracture modeling in newly developed areas such the NYS Marcellus Shale, engineers would blindly be making decisions on the size, type, and execution of HVHF treatments.

NYS' consultant, Alpha Geoscience, agreed with HCLLC's 2009 recommendations and in January 2011 reported to NYSDEC that:

> *Harvey Consulting's [HCLLC] assessment of the dSGEIS' discussion of hydraulic fracture design and monitoring is thorough…*
>
> *Harvey Consulting has thoroughly documented its discussion of hydraulic fracture design and monitoring, citing professional journal articles, professional conference papers, technical guidance documents, and consultant reports.*[106]

Alpha Geoscience recommended to NYSDEC that HCLLC's 2009 recommendations be included in the SGEIS:

> *Harvey Consulting's ideas should be considered for inclusion in the dSGEIS as possible permit conditions, especially for the first wells drilled in an area.*[107]

[106] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 26-27.

[107] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 28.

While Alpha Geoscience's report acknowledges the importance of proper HVHF design and monitoring, it includes several misrepresentations about HCLLC's 2009 comments that require correction.

First, Alpha Geoscience incorrectly contends that HCLLC recommended industry and NYS develop separate hydraulic fracture models; this is not correct. HCLLC recommended that industry develop models, **or** that joint model funding be implemented as a more cost-effective approach. Typically, companies build their own proprietary models to seek competitive advantage, especially in newly developed areas where the models are used as part of the competitive bidding process. However, it is possible for one or more companies to pool resources to develop a joint model as a cost savings.

Second, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform fracture modeling at every location, **including locations that have been thoroughly modeled and assessed.** Alpha Geoscience concluded that this would be extremely costly compared to the technical value. HCLLC did not recommend HVHF modeling be conducted at locations that have been "thoroughly modeled and assessed." Logically, if this work has already been completed, there is no reason to repeat it.

HCLLC did recommend that NYSDEC require operators to complete modeling prior to each fracture treatment to ensure that the fracture is properly designed and planned to be contained to the Marcellus Shale zone. This is not a significant amount of work per well for experienced operators, with working models. HCLLC also recommended that operators collect data during fracture treatments to further refine hydraulic fracture models. HCLLC pointed out that as NYS shale development is in its infancy, hydraulic fracture model work has not yet been completed, and therefore is needed.

Once a hydraulic fracture model is built and populated with data specific to the NYS Marcellus Shale, running a well-specific HVHF treatment scenario is an efficient process, and an important quality control and quality assurance measure. It does not appear that Alpha Geoscience is familiar with the reservoir simulators used for oil and gas work, because their recommendation to construct a hydraulic fracture model for the Marcellus Shale, and then use it only on the initial wells constructed, is inconsistent with industry practice. Model quality improves over time. As additional data is collected and the model is refined, it becomes an increasingly valuable tool to the operator. High-quality models are an essential tool for designing fracture treatments in challenging circumstances and locations.

In 2009, HCLLC explained that industry agrees there is a high level of uncertainty in NYS Marcellus Shale development; industry recommends engineering and geophysical data work to reduce that uncertainty. HCLLC's recommendations in 2009 stated:

> ***Marcellus Experience Very Limited:*** *Marcellus Shale gas development has a high level of uncertainty. Shales by nature are very heterogeneous.*[108] *Industry has limited experience exploiting the Marcellus Shale using horizontal wells and slickwater fracs. The first Appalachian Basin Marcellus Shale gas well stimulation using high-volume slickwater fracture treatments was only recently performed in Southwestern Pennsylvania in 2004.*[109] *Therefore, industry has less than five years of experience developing the Marcellus Shale using the techniques proposed in the dSGEIS.*

[108] Cipolla, C.L., Lolon, E.P., and Mayerhofer, M.J., Reservoir Modeling and Production Evaluation in Shale-Gas Reservoirs, International Petroleum Technology Conference, Paper 13185, December 2009.

[109] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.

Even NYSDEC's consultants acknowledge that industry literature on and experience with the Marcellus Shale is so limited that most of their analysis was based on development of other shale gas reservoirs, such as the Barnett and Fayetteville. NYSDEC's consultant, ICF, states that:

> *"**Drilling operations, and especially multi-horizontal wells, are relatively new in Marcellus Shale**. While drilling operations are underway in neighboring states as evidenced by over 450 wells in Pennsylvania for example, **technical studies have yet to be published** that quantify actual drilling operations in Marcellus Shale. **For the most part, we have had to make assumptions, where technically appropriate, that drilling operations in other shale formations are representative of expected Marcellus operations** [emphasis added].*[110]

Lack of Marcellus Shale experience increases the risk of fracturing out-of-zone, unless a conservative, step-wise approach is taken to better understand the Marcellus Shale before large scale development occurs in NYS.

***NYS Marcellus Data Set Improvement Needed**: Site-specific data, unique to the Marcellus Shale in NYS, must be collected to: better understand the reservoir heterogeneities; develop sophisticated three dimensional (3D) reservoir models to more accurately design fracture treatments; and examine actual fracture performance in the field. Reservoir simulation models are critical engineering design tools. The dSGEIS provides no indication that a model exists for the NYS Marcellus Shale.*

Engineers use 3D models to predict fracture height, length, and orientation prior to actually performing the job at the well. The goal is to design a stimulation treatment that optimizes fracture networking and maximizes gas production, while confining fracture growth to within the gas shale target formation.[111]

Engineers examine various parameters (e.g., volume, pressure, treatment placement) to optimize a fracture treatment. Without a high-quality 3D reservoir simulation model to design a fracture treatment, operators cannot demonstrate to NYSDEC that the fracture is predicted to stay in zone.

Typically an operator would start by collecting core analysis, well logs, and other subsurface data in the area it is interested in developing, to populate a site-specific 3D reservoir model. To collect this data, additional exploration and appraisal wells must be drilled (see recommendation No. 2). The limited amount of special core analysis and core data on the Marcellus Shale, as well as overlying intervals, is described in Chapter 4 of the DSGEIS, showing a need for additional data.

***Test in Deepest, Thickest Zones First:** NYSDEC is proposing to allow high-volume fracture treatments, without requiring the standard of care a petroleum engineer would typically use to collect data, and model, design, and monitor fracture treatments. NYSDEC should require that additional data be collected to support a model, and initially it should only allow a few, small fracture treatments that are conducted with intensive monitoring to verify that they are designed and implemented to stay within the*

[110] 2009 NYSDEC, DSGEIS, ICF Task 2 Report, Page 1.

[111] ALL Consulting, Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale, Presented at The Ground Water Protection Council 2008 Annual Forum, Cincinnati, Ohio, September 21-24, 2008.

Marcellus Shale. This data gathering and testing should be conducted in the deepest portions of the Marcellus Shale (below 4,000') and in the thickest section of the shale (over 150') to ensure there are adequate buffer zones to protect the environment during the data gathering and testing process. Operators should start with smaller fracture treatment sizes, collecting field data to better understand fracture performance, and use field data to calibrate that performance in the 3D model.

Over time, with careful analysis and a conservative, step-wise approach, larger fracture treatments can be tested and carefully monitored. Over time it may be possible to safely use the treatments on thinner reservoirs and shallower reservoirs, but certainly not as a first step. High-volume fracture treatments should not be conducted until there is a sophisticated data set, model, and monitoring program to verify pre-fracture and post-fracture reservoir properties.

Buffer Zones Needed: *Vertical fractures that extend above and below the shale zone will decrease gas recovery rates by allowing vertical migration into the overlying strata, or by allowing water influx from aquifers above or below the shale. NYS has a financial incentive to ensure fracture treatments are conducted correctly, because NYS will want to maximize its royalty share and tax revenue.*

To avoid fracturing out-of-zone, engineers typically design fracture treatments with a buffer zone (an un-fractured zone at the top of the shale layer and at the base of the shale). Buffer zone size should increase with geologic and technical uncertainty. Buffer zone size may decrease as industry gains experience and data quality/quantity improves. The DSGEIS does not contain sufficient information to demonstrate that NYSDEC and/or operators proposing high-volume fracture treatments have developed engineering tools capable of computing a safe buffer zone.

Third, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform a minifracture treatment at every location, including locations that have been thoroughly modeled and assessed. HCLLC did not recommend that a minifracture be conducted at every well. Instead, HCLLC recommended that minifractures be conducted in a few different areas of NYS to further refine hydraulic fracture models. HCLLC's 2009 recommendations stated:

Technology is available to assess actual fracture growth including: minifracs,[112] microseismic fracture mapping,[113] tilt surveys, well logging (e.g., tracer and temperature surveys[114]), etc.[115] These technologies can be used to provide more accurate assessments of the locations, geometry, and dimensions of a hydraulic fracture system.[116] ***This data***

[112] Minifracs are small fracture treatments conducted in the well to better understand fracture conductivity and flow geometry prior to implementing a large fracture treatment. Minifracs are typically used to optimize the fracture design and calibrate the fracture model. These tests involve periods of intermittent injection followed by intervals of shut-in and/or flowback. Pressure and rate are measured throughout a minifrac and recorded for subsequent analyses.

[113] Microseismic monitoring is a method that measures the seismic wave generated during a fracture treatment to map the fracture extent, and it can be used to make "real-time" changes in the fracture design and implementation program.

[114] After the fracture treatment is completed, an operator can run a temperature log in the well to measure the variation in reservoir temperature resulting from the treatment. The reservoir temperature is hotter than the fracture fluid and proppant. Cooler temperatures will be measured where frac fluid and proppant are placed. Temperature logs will provide insight into fracture location and growth outside the casing.

[115] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

[116] Schlumberger, Microseismic Hydraulic Fracture Monitoring, http://www.slb.com/content/services/stimulation/stimmap.asp.

> ***can be obtained in the Marcellus Shale in a few different areas of NYS to further refine the hydraulic fracture model.*** *Minifractures are particularly helpful in estimating fracture dimensions, fracture efficiency, closure pressure, and leakoff prior to implementing a high-volume, full-scale treatment. NYSDEC should require operators to conduct minifractures to better understand site-specific reservoir characteristics prior to conducting a high-volume fracture treatment [emphasis added].*

HCLLC's 2009 recommendations also noted that:

> ***While NYSDEC's consultant, ICF[117], documents a number of the engineering methods that can be used to model, monitor, and improve fracture treatments, NYSDEC does not require any of these methods in its existing regulations. Absent a regulatory requirement, there is no assurance these methods will be used*** *[emphasis added]*.
>
> *Best practice for hydraulic fracture planning includes a detailed understanding of the in-situ conditions present in the reservoir (e.g., shale thickness, reservoir pressure, rock fracture characteristics, and special core analysis). In highly heterogeneous reservoirs, reservoir simulation is often coupled with stochastic methods (e.g. Monte Carlo analysis and geostatistical techniques) to improve the quality of the 3D reservoir model.[118]*
>
> *Data collected on previous fracture treatments in the Marcellus Shale and drilling data will be useful to refine the fracture modeling. Actual fracture treatments must be carefully monitored and implemented to ensure fractures stay within zone. Data collected during each fracture treatment should be used to calibrate the 3D reservoir model to improve future fracture treatment design.*
>
> *Peer-reviewed articles and technical data on Marcellus Shale vertical fracture growth characteristics are sparse. While fracture growth models exist at an industry level, and have been tuned for fracture treatments in the Barnett Shales and other gas reservoirs, considerable technical work is still needed to develop fracture growth models for NYS Marcellus Shale development.*
>
> *A literature review was completed by the author [HCLLC] in search of a Marcellus Shale 3D reservoir model for NYS; none was found in the petroleum engineering published literature. It is not clear if the lack of a Marcellus Shale reservoir model for NYS indicates that one does not exist, or whether industry is holding models proprietary. Yet in other shale gas developments (e.g., Barnett and Fayetteville) there is extensive industry literature on: available reservoir simulation model; completion and fracture design; and performance assessment to compare predicted fracture growth with that achieved in the field. Lack of industry literature is usually a strong indication that additional data gathering and technology development is needed.*
>
> *The data void for NYS' Marcellus Shale technical literature reinforces the need for NYSDEC to use a conservative, step-wise approach, rather than launching into a massive drilling and fracturing campaign without the data or tools in place to do a safe and effective job.*

[117] ICF International, Technical Assistance to NYS on DSGEIS, August 2009.

[118] Schepers, K.C., Gonzalez, R.J., Koperna, G.J., and Oudinot, A.Y., Reservoir Modeling in Support of Shale Gas Exploration, Society of Petroleum Engineers, June 2009.

NYSDEC should require additional information be collected by industry to better understand the geological and geophysical properties of the Marcellus Shale zone and the overlying strata between the Marcellus and drinking water aquifers.

NYSDEC should require 3D reservoir simulation models be developed to accurately predict hydraulic fracture treatment performance, and to ensure the jobs are well engineered and designed with adequate safety factors to avoid fracturing out-of-zone.

The DSGEIS must assure the public that fractures can be contained to the Marcellus Shale zone. The DSGEIS does not provide data sufficient to meet this standard. The DSGEIS does not document the existence of 3D reservoir simulation models for NYS' Marcellus Shale, nor does NYSDEC require engineers to design fracture treatments using 3D models.

While Marcellus Shale development in Pennsylvania precedes development in NYS, data collected from the Pennsylvania wells is not applicable to the NYS Marcellus Shale because the depth of burial, thickness, organic content, permeability, and other reservoir properties in NYS differ. Industry experts warn that site-specific data is critical:

*"**By their nature, shales are extremely variable and regional differences in structure, mineralogy and other characteristics should always be considered in treatment design**…The wide geographic range [of the Marcellus Shale] has led to numerous different completion schemes being utilized as with the geographic variation comes geologic variability within the formation itself. A primary topic of [industry] discussion has been determining the optimal size and type of stimulation treatment for a given area"* [119] *[emphasis added].*

Marcellus Shale thickness lessens substantially in western NYS to less than 75' for roughly one-third of the total anticipated development area.[120] HVHF treatments in thin shale zones increases the risk of fracturing out-of-zone, unless a very cautious approach is taken by tailoring the design to the geophysical properties of the shale, taking into account shale thickness, local stress conditions, compressibility, and rigidity.

NYSDEC's consultants point out that a gas operator has no incentive to fracture out of the Marcellus Shale zone, because doing so could result in a loss of gas reserves or an increase in produced water volumes. Yet, NYSDEC's consultant, ICF, also recognizes that fracture design is complicated and it is possible to inadvertently fracture out-of-zone. ICF examined the potential for fracture fluids to propagate vertically and contaminate overlying drinking water aquifers. ICF recommended a 1,000' vertical offset be used.

HCLLC agrees that the use of vertical and horizontal offsets (buffer zones) is a prudent approach. The next step is to determine the size of the offsets. Initially, in new areas, offsets should be large, and then may decrease over time, as field data is obtained and predictive capability is refined.

[119] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.

[120] 2009 NYSDEC, DSGEIS, Figure 4.9.

In 2009, HCLLC pointed out that the 1,000' vertical offset proposed by ICF is not technically supported, and a horizontal buffer zone is also needed. HCLLC recommended that vertical and horizontal offsets be based on actual field data, 3D reservoir simulation modeling, and a peer-reviewed hydrological assessment. HCLLC recommended these steps be taken to ensure aquifers are protected and nearby wellbore intersections are avoided.

The 2011 RDSGEIS still does not provide technical justification for the proposed minimum 1,000' vertical offset, nor does it make a recommendation for a horizontal offset from existing wells.

Instead, the 2011 RDSGEIS provides data that shows HVHF treatments in the Marcellus Shale have propagated vertical fractures up to 1500' in length, and horizontal fractures can extend hundreds to thousands of feet, as further explained below. These data do not support the proposed buffers.

The 2011 RDSGEIS: The 2011 RDSGEIS agrees that in new areas hydraulic fracture model development and design is important, citing recommendations from the Ground Water Protection Council and its consultant ICF; yet, incongruously the RDSGEIS concludes it is unnecessary for operators to be required do this work in NYS (as a SGEIS mitigation measure or a NYCRR requirement).

> *Service companies design hydraulic fracturing procedures based on the rock properties of the prospective hydrocarbon reservoir. For any given area and formation, hydraulic fracturing design is an iterative process, i.e., it is continually improved and refined as development progresses and more data is collected.* ***In a new area, it may begin with computer modeling to simulate various fracturing designs and their effect on the height, length and orientation of the induced fractures. After the procedure is actually performed, the data gathered can be used to optimize future treatments. Data to define the extent and orientation of fracturing may be gathered during fracturing treatments by use of microseismic fracture mapping, tilt measurements, tracers, or proppant tagging. ICF International, under contract to NYSERDA*** *to provide research assistance for this document,* ***observed that fracture monitoring by these methods*** *is not regularly used because of cost, but* ***is commonly reserved for evaluating new techniques, determining the effectiveness of fracturing in newly developed areas, or calibrating hydraulic fracturing models*** *[emphasis added].*[121]

NYSDEC's consultants (Alpha Geoscience and ICF), the Ground Water Protection Council, HCLLC, and industry all agree:

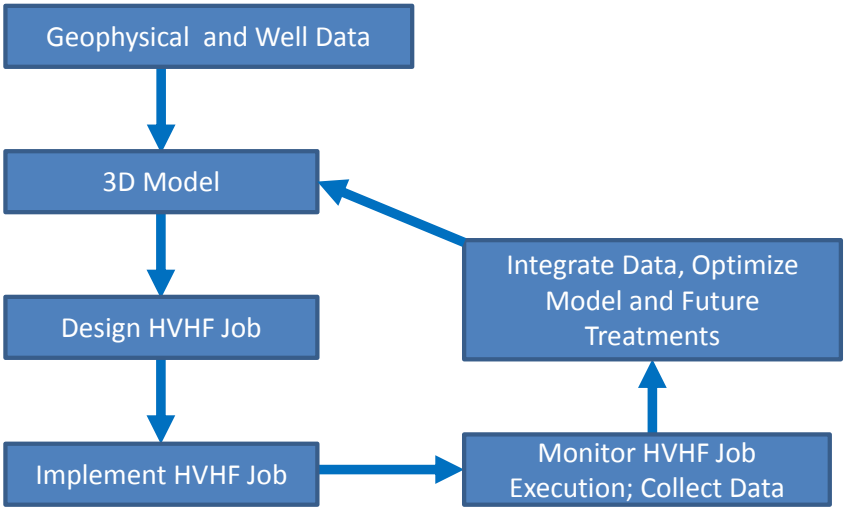
- There is a need for computer modeling on new gas shale play areas to simulate various fracturing designs and their effects on the height, length, and orientation of the induced fractures;
- After the HVHF treatment is actually performed, gathered data should be used to optimize future treatments; and
- There is technology available to further refine treatment design, including microseismic fracture mapping, tilt measurements, tracers, and proppant tagging.

However, these points of agreement are not reflected in the RDSGEIS, permit conditions, or NYCRR revisions. Remarkably, the 2011 RDSGEIS only has a few paragraphs in the entire 1,537 page document that discuss the importance of HVHF modeling and post-fracture assessment work (Chapter 5.8), and these recommendations are later disregarded in Chapter 7 proposed mitigation.

[121] 2011 NYSDEC, RDSGEIS, Page 5-88.

The use of 3D reservoir simulation to more accurately predict vertical and horizontal fracture growth is not new; reservoir simulation models have been used by petroleum engineers for decades. However, computational efficiency and model design have improved considerably, and more sophisticated simulation techniques are now available for shale gas reservoirs.

The basic engineering approach for populating a 3D reservoir simulation model is shown in the simplified flow diagram below, with geophysical data (seismic, well logs, core, samples, etc.) and existing nearby well data serving as the starting point. Once a model is built, it is used to design and optimize a safe and effective HVHF job. Data are gathered while the job is implemented, and those data are used to refine the model and improve future HVHF treatments.



There is abundant industry literature explaining the need for hydraulic fracture modeling and microseismic mapping, especially for new shale play developments, such as in NYS.

NYSDEC should recognize that the use of refined, site-specific models to optimize HVHF jobs is industry best practice. Quality operators with high standards routinely do this work. It should not be considered a burdensome practice, but rather a necessary requirement to protect groundwater and the environment.

Furthermore, it is economically attractive for an operator to use HVHF modeling. Models aid industry in making informed decisions, and prevents fracturing out-of-zone, which maximizes gas recovery rates.

Microseismic mapping has become a key tool for better understanding shale gas heterogeneities, identifying reservoir faults, and measuring actual fracture propagation orientation and length.

A 2010 industry paper[122] written by Rex Energy Corporation and MicroSeismic Inc. explains the importance of microseismic mapping for shale gas engineering:

> *By using microseismic source locations and mechanisms in conjunction with other geological and geophysical knowledge of an area, engineering and completion methods can be quickly corrected and enhanced. Induced fracture height, length, and placement influence the location, orientation and spacing of subsequent wells.* ***Microseismic monitoring allows for identification and characterization of unknown faults which intersect the wellbore and may significantly affect reservoir production and stimulations****. Formations with limited exploration with limited exploration data, such as the Marcellus shale, are ideal candidates for microseismic monitoring [emphasis added].*
>
> *In this case study, we will show how the* ***microseismic monitoring of a hydraulic fracture treatment in the Marcellus Shale identified a pre-existing natural fault which intersected the wellbore*** *[emphasis added].*

A 2011 industry paper[123] written by Marquette Exploration (a Marcellus Shale operator) and Schlumberger (an industry contractor), titled "Integrating All Available Data to Improve Production in the Marcellus Shale," emphasizes the importance of HVHF design and monitoring:

> *The operator featured in this paper is a small independent with Marcellus Shale areas of operation spanning across Belmont and Jefferson counties, eastern Ohio (Fig.2). This paper describes the methodology used by the operator to systematically gather the critical data during a pilot program to enhance the knowledge of their reservoir and develop optimized completion strategies and stimulation designs, thereby maximizing the true economic value of their asset.*
>
> *To build realistic property models, input from team members from different disciplines is required; in this study, team members included a geophysicist, geologist, petrophysicist, and reservoir engineer. Once the 3D structural model was completed, individual log measurements and interpreted properties from petrophysical, geomechanical, and image logs were incorporated in the model.*

Marquette Exploration's paper concludes:

- *Delineating a reservoir early on in the play and gathering as much data as possible can improve the drilling and completion design of the initial horizontal wells in the field to reduce the time and cost for an operator to get up the learning curve.*
- *Using all available data can greatly enhance the understanding in a field which, in turn, can improve the lateral design. Core data are imperative to calibrate petrophysical and geomechanical logs to further refine log models in other wells in an area.*
- *Seismic data in conjunction with strategically placed vertical logs can be used to construct a detailed static 3D geological model.*

[122] Hulsey, B.J., and Cornette, B. (MicroSeismic Inc.), and Pratt, D. (Rex Energy Corporation), Surface Microseismic Mapping Reveals Details of the Marcellus Shale, Society of Petroleum Engineers, SPE Paper 138806, 2010, Page 1.

[123] Ejofodomi, E., Baihly, J., Malpani, R., Altman, R, (Schlumberger), and Huchton, T., Welch, D., and Zieche, J., (Marquette Exploration), Integrating All Available Data to Improve Production in the Marcellus Shale, Society of Petroleum Engineers Paper, SPE 144321, 2011.

- *The thickness, depth, and continuity for shale sub-layers can vary greatly over a small area, so a pilot hole can be imperative to calibrate the geologic model for lateral landing point determination.*
- *The geologic model showed that the reservoir properties varied across the area of interest.*
- *Stochastic modeling can be used to successfully propagate interpreted log properties from a few wells across a large acreage.*
- *A novel reservoir modeling technique, Microseismic Fracture Network (MFN), was developed using microseismic data to properly describe the created complex fracture network.*

A 2010 industry paper[124] written by El Paso Exploration and Production and StrataGen Engineering stresses the importance of HVHF design:

> *…a primary conclusion is that as reservoir permeability decreases, proper well type selection and* ***effective hydraulic fracture stimulation design become much more crucial*** *[emphasis added].*
>
> ***Additional modeling with specifics must be performed to evaluate well type, fracture design, and spacing requirement for a specific well or formation*** *[emphasis added].*

A 2011 industry paper[125] written by Schlumberger also stresses the importance of HVHF design and monitoring:

> *The completion strategy and hydraulic fracture stimulation are the keys to economic success in unconventional reservoirs.* ***Therefore, reservoir engineering workflows in unconventional reservoirs need to focus on completion and stimulation optimization*** *as much as they do well placement and spacing.* ***This well-level focus requires the integration of hydraulic fracture modeling software and the ability to utilize measurements specific to unconventional reservoirs*** *[emphasis added].*
>
> ***It is very important to properly model hydraulic fracture propagation and hydrocarbon production mechanisms in unconventional reservoirs****, a significant departure from conventional reservoir simulation workflows.* ***Seismic-to-simulation workflows in unconventional reservoirs require hydraulic fracture models that properly simulate complex fracture propagation*** *which is common in many unconventional reservoirs, algorithms to automatically develop discrete reservoir simulation grids to rigorously model the hydrocarbon production from complex hydraulic fractures, and the ability to efficiently integrate microseismic measurements with geological and geophysical data.* ***The introduction of complex hydraulic fracture propagation models now allows these workflows to be implemented*** *[emphasis added].*

A 2010 industry paper[126] written by StrataGen Engineering and CMG (industry consultants) again highlights the importance of HVHF design and monitoring:

[124] Shelley, R.F., Lolon, E., and Dzubin, B. (StrataGen Engineering), and Vennes, M. (El Paso Exploration and Production), Quantifying the Effects of Well Type and Hydraulic Fracture Selection on Recovery for Various Reservoir Permeability Using a Numerical Reservoir Simulator, Society of Petroleum Engineers Paper, SPE 133985, 2010, Pages 1 and 12.

[125] Cipolla, C.L., Fitzpatrick, T., Williams, M.J., and Ganguly, U.K., (Schlumberger), Seismic-to-Simulation for Unconventional Reservoir Development, Society of Petroleum Engineers Paper, SPE 146876, 2011, Page 1.

> *The widespread application of microseismic mapping has significantly improved our understanding of hydraulic fracture growth in unconventional gas reservoirs (primarily shale) and led to better stimulation designs. However, the overall effectiveness of stimulation treatments is difficult to determine from microseismic mapping, as the location of proppant and distribution of conductivity in the fracture network cannot be measured (and are critical parameters that control well performance). Therefore* ***it is important to develop reservoir modeling approaches that properly characterize fluid flow in and the properties of a complex fracture network, tight matrix, and primary hydraulic fracture (if present) to evaluate well performance and understand critical parameters that affect gas recovery*** *[emphasis added].*
>
> *Given the complex nature of hydraulic fracture growth and the very low permeability of the matrix rock in many shale-gas reservoirs combined with the predominance of horizontal completions,* ***reservoir simulation is commonly the preferred method to predict and evaluate well performance*** *[emphasis added].*
>
> *The most rigorous method to model shale-gas reservoirs is to discretely grid the entire reservoir, including the network fractures, hydraulic fracture, matrix blocks, and un-stimulated areas – but this increases computational time. However, with the continual advances in computing power, much more complex numerical models can be efficiently utilized.*

In 2010, Atlas Energy Resources published a Society of Petroleum Engineering Paper that explained the importance of reservoir characterization, modeling, the use of minifracs, and the use of microseismic data. Atlas Energy Resources explained that the use of advanced technology is good business:

> *This paper describes a procedure to enhance production in the Marcellus shale while optimizing economics through integration of minifrac, fracture treatment, microseismic, and production data technologies.*
>
> *Application of this integrated technology approach will help prodvide the operator with a systematic approach for designing, analyzing, and optimizing multi-stage/multi-cluster transverse hydraulic fractures in horizontal wellbores.*[127]

An engineering analysis and modeling prior to a HVHF treatment provides industry, regulators, and the public with confidence that the treatment has been thoroughly evaluated and designed to protect the environment. It is not sufficient for industry and NYSDEC to say this work is being done, while being unwilling to require it. If this work is being done, then creating a formal requirement in the SGEIS and NYCRR does not impose an incremental burden on the operator. Resistance to a formal requirement should signal to NYSDEC that industry best practice is not always followed.

While industry literature explains the need for hydraulic fracture modeling, this does not guarantee it will actually be implemented by all shale gas operators in NYS. Shale gas drilling has attracted numerous small, less experienced operators. Computational modeling requires personnel with expertise in building models, running them, and refining datasets. If the operator does not have sufficient in-house engineering and geophysical expertise, it should be required to hire experts to provide the necessary expertise.

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[126] Cipolla, C.L., Lolon, E.P. (StrataGen Engineering), Erdle, J.C., and Rubin, B. (CMG), Reservoir Modeling in Shale-Gas Reservoirs, Society of Petroleum Engineers Paper, SPE 125530, 2009, Pages 1,3, and 4.

[127] Henry Jacot, R. (Atlas Energy Resources), Bazan, L.W. (Bazan Consulting, Inc.), Meyer, B.R. (Meyer & Associates Inc.), Technology Integration – A Methodology to Enhance Production and Maximize Economics in Horizontal Marcellus Shale Wells, Society of Petroleum Engineers Paper, SPE 135262, 2010, Page 1.

Recommendation No. 32: Best practices for HVHF design and monitoring should be included in the SGEIS as a mitigation measure, and codified in NYCRR as a minimum standard.

Additionally, Alpha Geoscience, ICF, Ground Water Protection Council, HCLLC, and industry all agree that additional technical work is needed to develop new shale gas play areas; yet the 2011 RDSGEIS does not require the operator to develop or maintain a hydraulic fracture model. Instead, the 2011 RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned.[128]

Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. This approach would not be in NYS' best interest.

Instead, NYS needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective, it is also good business because it optimizes gas production and reduces hydraulic fracture treatment costs.

The 2011 RDSGEIS does not require a HVHF design plan.[129] The RDSGEIS does not require the operator to:

(a) Estimate the vertical and horizontal fracture length;

(b) Verify that the proposed HVHF design will not intersect protected groundwater or nearby wells;

(c) Use a site-specific hydraulic fracture model, based on NYS specific shale characteristics and the operational design parameters of the planned HVHF job (volume, pressure, rate, etc.).

Recommendation No. 33: The SGEIS and NYCRR should require the operator to:

(a) Estimate the maximum vertical and horizontal fracture propagation length for each well, and submit technical information (e.g. model output) with its application to support its computations.

(b) Describe in its post-well completion report whether the predicted vertical and horizontal fracture propagation lengths were accurate, or note discrepancies.

(c) Certify that the actual HVHF job was implemented safely, and fracture propagations did not intersect protected aquifers or nearby wells.

Additionally, NYS should reserve the right, and provide funding, to periodically review industry's models and computations to assess quality and verify this work is being completed.

[128] 2011 NYSDEC, RDSGEIS, Page 5-88.

[129] The operator is only required to verify that the vertical offset of 1000' is achieved and the shale is at least 2000' deep.

The 2011 RDSGEIS assumes that any HVHF job, no matter the volume, no matter the pressure, and no matter the shale thickness, will be safe, as long as it is conducted at a depth below 2,000'. The 2011 RDSGEIS recommends that site-specific SEQRA reviews be limited to wells shallower than 2000' and within 1000' of a protected aquifer.[130] The RDSGEIS lacks technical and scientific data to support the hypothesis that all HVHF treatments, regardless of design, at 2000' or deeper will be safe. Additionally, the RDSGEIS does not address safe horizontal fracture length.

NYSDEC does not provide data on HVHF treatments conducted between 2000' and 5000' deep; yet, NYS proposed to allow shale gas drilling at these depths. Instead, the RDSGEIS relies on limited data collected from Marcellus Shale fractures conducted in other states at depths below 5000'. However, even industry points out that data collected in one part of the Marcellus Shale cannot be applied to the entire shale.

For example, Guardian Exploration and Universal Well Services reports that optimal Marcellus Shale HVHF treatments are still being developed, and that a "one-size-fits-all approach should not be expected. They anticipate that industry will examine the use of higher rates and increased fluid volume and proppant mass in the future resulting in varied fracture lengths from current HVHF jobs:

> ***Much work remains to be done in determining the optimal stimulation treatment for the Marcellus shale***. ***Certainly given the extremely large geographic area encompassed by the Marcellus play, it should not be expected that one size will fit all.*** *While the treatment discussed here has been considered successful,* ***future projects will examine the effects of increased rate, increased volumes in terms of both overall fluid volume and proppant mass, the effects of varying the proppant mesh ratios and concentrations, and optimization of flowback/cleanup rates***. *The utilization of evaluation tools such as microseismic monitoring of fracture growth and horizontal drilling and completions to enhance reservoir development should also prove to be beneficial [emphasis added].*[131]

As HVHF treatment methods continue to evolve, NYSDEC must either set a limit in the SGEIS and NYCRR for the upper bounds of a safe HVHF job, or it must have a process in place for industry to provide site-specific engineering to support each well application to ensure that new HVHF designs are safe.

NYSDEC assumes that 1000' vertical separation between the bottom of the protected groundwater zone and the top of the shale zone where HVHF will occur is sufficiently protective, regardless of shale thickness, HVHF job size, and other subsurface characteristics. However, this approach is not technically supported. The 2011 RDSGEIS concludes:

> *As explained in Section 6.1.5.2, the conclusion that* ***harm from fracturing fluid migration up from the horizontal wellbore is not reasonably anticipated is contingent upon the presence of certain natural conditions, including 1,000 feet of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone.*** *The presence of 1,000 feet of low-permeability rocks between the fracture zone and a drinking water source serves as a natural or inherent mitigation measure that protects against groundwater contamination from hydraulic fracturing [emphasis added].*[132]

[130] 2011 NYSDEC, RDSGEIS, Page 7-59.

[131] Fontaine, J., and Johnson, N. (Universal Well Services), and Schoen, D. (Guardian Exploration), Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper, SPE 117772, 2008, Page 11.

[132] 2011 NYSDEC, RDSGEIS, Page 7-59.

Neither the 2009 DSGEIS nor the 2011 RDSGEIS contain site-specific NYS Marcellus Shale hydraulic fracture model data to support NYSDEC's conclusion that a 1,000' vertical separation will be protective in all cases in NYS, especially where thinner, shallower shales are present. Furthermore, the 2011 RDSGEIS lacks data on vertical and horizontal fracture propagation in the Marcellus Shale at depths between 2000' and 5000' (depths that NYS proposes to permit).

The behavior of HVHF propagation in NYS is not currently well understood. HCLLC was unable to locate any NYS site-specific hydraulic fracture models for the Marcellus, Utica, or other low-permeability reservoirs. If these models exist, they should be described in the SGEIS, and NYSDEC should explain how it used the data from these models to inform its SGEIS.

Instead, the RDSGEIS currently relies on Marcellus Shale HVHF data from other states that may not be applicable to NYS. For example, NYSDEC points to data collected on 400 Marcellus hydraulic fractures conducted in Pennsylvania, West Virginia, and Ohio. This data was summarized in a three page article in the American Oil & Gas Reporter in July 2010:

> *Four hundred Marcellus hydraulic fracturing stages in Pennsylvania, West Virginia and Ohio have been mapped with respect to vertical growth and distance to the deepest water wells in the corresponding areas. Although many of the hydraulic fracturing stages occurred at depths greater than the depths at which the Marcellus occurs in New York, the results across all depth ranges showed that induced fractures did not approach the depth of drinking water aquifers. In addition, as previously discussed, at the shallow end of the target depth range in New York, fracture growth orientation would change from vertical to horizontal.*[133]

NYSDEC's conclusions rely heavily on the American Oil & Gas Reporter three-page article (Fisher, 2010); yet NYSDEC does not further investigate the origin of the data contained in this article or its implications for shale development in NYS. Fracture growth is a function of type of formations located above and below the Marcellus Shale. Subsurface geology will vary across states and the RDSGEIS does not explain how this data is applicable to NYS. For example, this article:

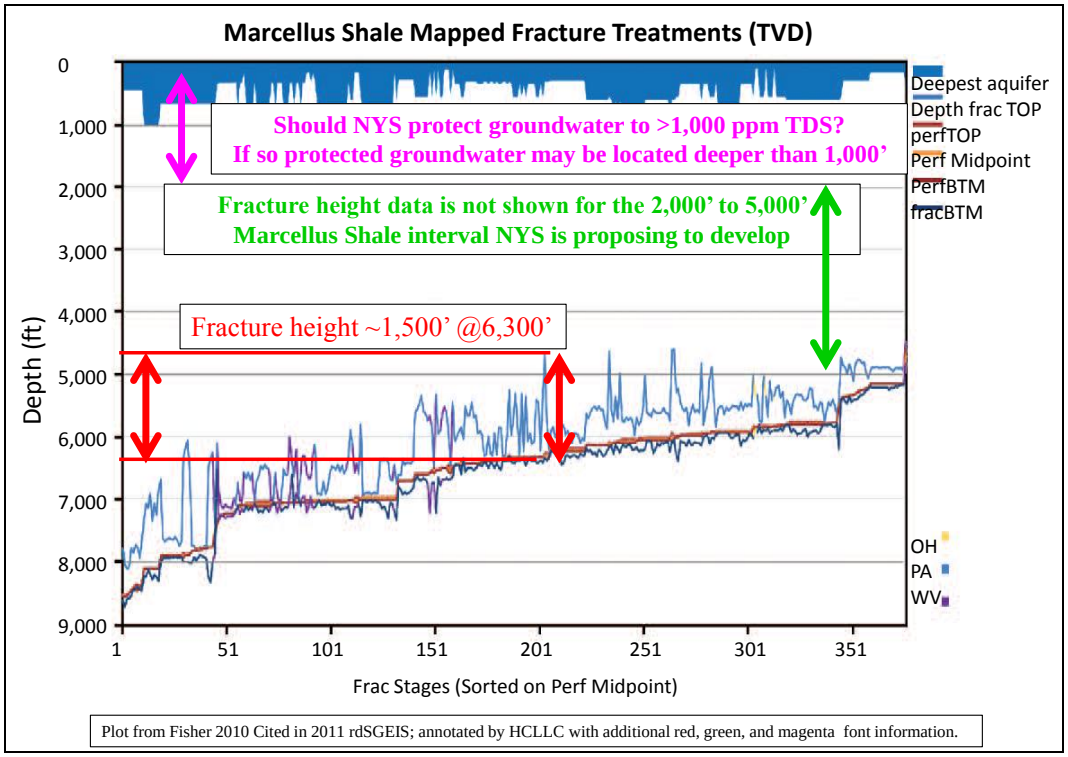
- Does not provide any information on the maximum HVHF job size (volumes, pressures, rates, etc.) to verify whether the fracture treatments conducted and analyzed are equivalent to the maximum HVHF job size anticipated in NYS;
- Does not provide any information on the Marcellus Shale thickness or geophysical properties present during the HVHF treatments;
- Shows that vertical fractures in excess of 1000' were observed (the plot, which is copied from the Fisher 2010 report and provided below, shows a 1500' vertical fracture propagated at 6300');
- Does not show what the vertical fracture growth height would be in the 2000-5000' Marcellus Shale depth interval that NYS proposes to develop; and,
- Does not show the horizontal distance that a fracture will propagate at the shallower shale depths NYS plans to develop.

[133] 2011 NYSDEC, RDSGEIS, Page 6-56.

A more in-depth technical paper written by Kevin Fisher (Halliburton) in 2011 appears to be the origin of the data cited in the American Oil & Gas Reporter article. Fisher's 2011 paper[134] concludes that:

> ***Fracture lengths can sometimes exceed a thousand feet*** *when contained with a relatively homogeneous layer [emphasis added].*
>
> ***At depths deeper than about 2,000 ft****, the vertical stress or overburden is generally the largest single stress so* ***the principal fracture orientation is expected to be vertical*** *on deeper wells [emphasis added].*
>
> ***At some point on shallow wells, the overburden stress will decrease to a point where it is less than the maximum horizontal stress and, at this point, one would expect the fracture growth to be horizontal and not vertical.*** *As wells get shallower, and the overburden stress lessens, mapped fractures are typically observed exhibiting increasingly larger horizontal components.* ***All of the fractures do not necessarily turn horizontal; they might have significant vertical and horizontal components with more of a T-shaped geometry,*** *but the horizontal components can become significant and could thieve away enough fluid causing a blunting effect, limiting upward fracture-height growth [emphasis added].*

The Marcellus fracture height figure shown in the American Oil & Gas Reporter is provided below; HCLLC annotated it to identify additional evaluation that is needed for NYS.



Plot from Fisher 2010 Cited in 2011 rdSGEIS; annotated by HCLLC with additional red, green, and magenta font information.

The use of vertical offset limits to separate hydrocarbon recovery operations from protected aquifers is a reasonable approach, but it must be scientifically and technical supported. While it is possible that a 1,000' vertical offset may potentially be sufficiently protective; the 2011 RDSGEIS does not provide sufficient scientific data or technical examination to support this recommended threshold.

[134] Fisher, K. and Warpinski, N., Pinnacle- A Halliburton Service, Hydraulic Fracture-Height Growth: Real Data, Society of Petroleum Engineers Paper, SPE 145949, 2011, Pages 1-2 and 5.

In addition to understanding the maximum vertical fracture propagation height, horizontal fracture propagation distance is an important consideration, especially when developing shallower shale zones. Fractures in shallower formations will tend to propagate on the horizontal plane. HVHF treatments should be designed to prevent fractures from intersecting with existing improperly constructed and improperly abandoned wells, and transmissive faults and fractures, which can provide pollutants a direct pathway to protected groundwater resources.

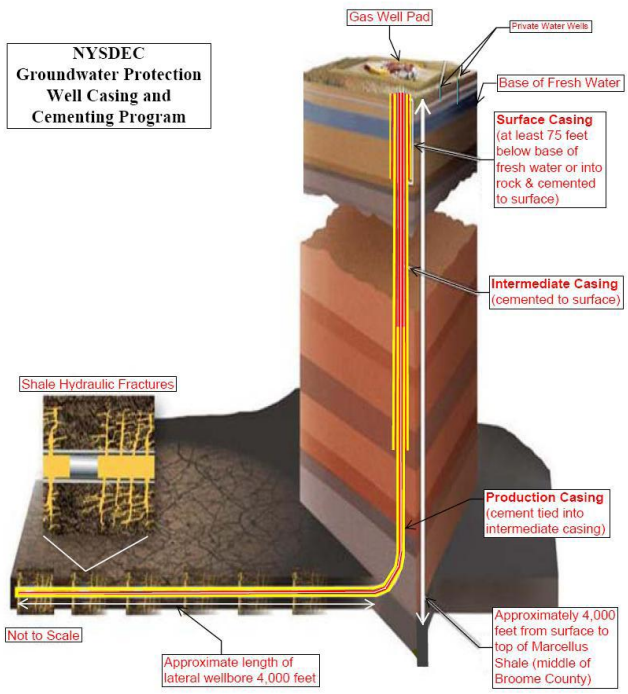
For example, in 2010 the BC Oil & Gas Commission issued a safety advisory on the risks of fracture treatments intersecting adjacent wells. The advisory specifically notified industry that:

> *A large kick was recently taken on a well being horizontally drilled for unconventional gas production in the Montney formation**. The kick was caused by a fracturing operation being conducted on an adjacent horizontal well. Fracture sand was circulated from the drilling wellbore, which was 670m [~2200'] from the wellbore undergoing the fracturing operation.** [emphasis added].*[135]

Additionally, the advisory reported 18 known fracture communication incidents in B.C. and one in Western Alberta: five incidents of fracture stimulation communicating with an adjacent well; three incidents of drilling into a hydraulic fracture formed during a previous stimulation on an adjacent well and containing high pressure fluids; 10 incidents of fracture stimulations communicating into adjacent producing wells, and one incident of fracture stimulations communication into an adjacent leg on the same well for a multi-lateral well. Therefore fracture stimulations communication with adjacent wells is a known and reasonably foreseeable risk.

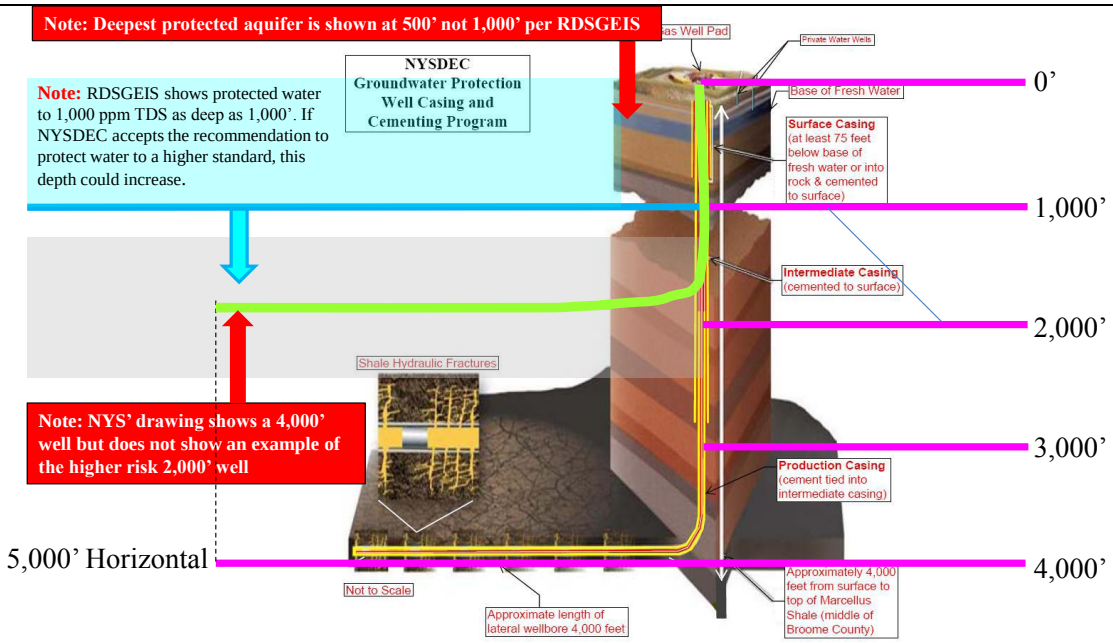
The 2011 RDSGEIS includes a wellbore schematic used in presentations given by the NYSDEC Commissioner. This wellbore schematic, shown below, depicts an example Marcellus Shale well. In the example the base of freshwater is at 500', the well is drilled to a depth of 4,000', and the horizontal length of the well is 4,000'.

[135] BC Oil & Gas Commission, Safety Advisory 2010-03, Communication During Fracture Stimulation, May 20, 2010.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing showing a 500' freshwater depth and a 4,000' HVHF well.

The drawing does not represent the highest risk wells proposed in the 2011 RDSGEIS. The highest risk wells allowed under the 2011 RDSGEIS would be drilled into a thin section of the Marcellus Shale at a 2,000' depth, with protected water located above at 1,000'. Below is an annotated version of this wellbore schematic, prepared by HCLLC, showing the higher risk wells proposed under the RDSGEIS.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing was annotated by HCLLC to show a HVHF well constructed at 2,000' depth, the base of freshwater at least at 1,000' and a theoretical uncertainty zone associated with vertical and horizontal fracture propagation at 2,000' depth.

As explained in Chapter 9 of this report , if a HVHF treatment intersects with a nearby improperly abandoned well, the potential exists for the improperly abandoned well to become a vertical conduit, and therefore transfer hydraulic fluid and mobilized gas to protected aquifers. Additionally, the pollution risk posed by possible HVHF intersections is not limited to improperly abandoned wells; existing wells that were poorly designed and constructed could also pose a risk.

Physics dictate that fractures form perpendicular to the direction of the least amount of stress. Vertical fracture height will decrease with depth, and horizontal fracture length will increase.

NYSDEC proposes that operators identify wells within a mile radius around the surface location of a HVHF well, to identify wells that might be at risk of intersection with HVHF treatments.[136] However, NYSDEC does not provide technical data to support a mile radius. The 2011 RDSGEIS does not specify a maximum horizontal drilling length. Although NYSDEC's spacing rules may impose some limitation on this length, limitations are not clearly explained in the RDSGEIS.

The RDSGEIS should identify the maximum horizontal fracture propagation distance that could occur in a shallow well to ensure that HVHF treatments do not intersect existing wellbores. This should be included in the SGEIS. Limits on horizontal drilling section lengths and HVHF job size, including a safety zone around each HVHF well, should also be established.

Recommendation No. 34: The SGEIS should provide a basis for the maximum horizontal well drilling limit. The SGEIS should also explain how the operator will verify that the maximum horizontal well drilling limit, plus the maximum predicted horizontal fracture length, will avoid nearby well intersection.

The most logical way forward is to begin by limiting development to the deepest Marcellus Shale intervals, maximizing the vertical separation from drinking water aquifers. Once accurate, field-calibrated 3D reservoir simulation models are available for NYS, development can then move to shallower intervals, as long as technical data shows that treatments will remain in zone.

Recommendation No. 35: The SGEIS should technically justify vertical and horizontal HVHF treatment offsets. Proposed offsets should be supported by hydraulic fracture modeling. Modeling should reflect the maximum HVHF job designs allowed in NYS and shale reservoir characteristics. NYSDEC should provide public access to the scientific data and hydraulic fracture models it uses to develop vertical and horizontal offsets for the purposes of the SGEIS.

Drilling into the deepest, thickest Marcellus Shale intervals (e.g., below 4000') will maximize data collection, affording access to all overlying intervals. Core samples, well logs, and pressure transient data can be obtained, verifying whether there are continuous permeability barriers hydraulically separating the Marcellus Shale and the overlying drinking water aquifers, and geologic barriers that will limit fracture propagation. Initially, smaller fracture treatments should be used as tests. These treatments can be increased in size over time, if data support the conclusion that large fracture treatments can remain in zone. As data are collected, and 3D reservoir models are developed and refined, it may be possible to safely develop the Marcellus at shallower depths and in thinner intervals.

NYSDEC's recommendation to move forward with shale gas development, absent additional engineering data and hydraulic fracture models, is technically unsupported and in direct conflict with the information cited in its 2009 DSGEIS and 2011 RDSGEIS, as well as its own consultants' recommendations.

[136] 2011 NYSDEC, RDSGEIS, Page 6-56.

Recommendation No. 36: The SGEIS should include a more thorough examination of hydraulic fracture modeling. The SGEIS and NYCRR should require the operator to:

(a) Collect additional geophysical and reservoir data to support a reservoir simulation model;

(b) Develop a high-quality Marcellus Shale 3D reservoir model(s) to safely design fracture treatments;

(c) Maintain and run hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone;

(d) Collect and carefully analyze data from HVHF treatments to optimize future HVHF treatments;

(e) Initially complete HVHF treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience before proceeding to shallower zones (e.g. 4000' deep and 150' thick, progressively moving shallower as more NYS site-specific information is collected); and

(f) Conduct post-fracture analysis, and provide that analysis to NYS to demonstrate that the HVHF treatment was safely implemented.

NYCRR Proposed Revisions: There are no proposed revisions in the NYCRR. As proposed, the NYCRR do not require operators to:

(a) Submit a HVHF designs to NYS;

(b) Estimate the vertical and horizontal fracture length;

(c) Provide engineering analysis and run HVHF modeling;

(d) Monitor HVHF performance to ensure that HVHF design and actual implementation in the field match; and

(e) Notify NYSDEC if the actual vertical and/or horizontal fracture length greatly exceeds the job design, such that risk may be present to the environment.

11. Hydraulic Fracture Treatment Additive Limitations

Background: In 2009, HCLLC recommended that NYS regulations identify fracture treatment additives that are protective of human health and the environment. HCLLC also recommended that the NYCRR include a list of prohibited chemical additives.

2011 RDSGEIS: The 2011 RDSGEIS includes improvements in the handling and storage of HVHF chemicals by requiring chemicals to be stored in suitable containers placed in secondary containment. Additionally, NYSDEC encourages operators to select the lowest toxicity chemicals. However, neither the 2011 RDSGEIS nor the proposed NYCRR amendments establish a prohibited chemical list, nor do they **require** an operator to use the lowest toxicity chemicals. Instead, the 2011 RDSGEIS requires only that the operator evaluate alternative products. Ultimately, the operator is allowed to select the final chemicals used with no firm evaluation criteria listed in the NYCRR to rule out harmful chemicals.

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.3(c)(1)(v) require only that the operator provide:

> *Documentation that proposed chemical additives exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment than available alternatives; or documentation that available alternative products are not equally effective or feasible.*

The proposed regulation requires the operator to examine chemicals that "exhibit reduced aquatic toxicity" and a "lower risk to water resources," but the NYCRR does not provide specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk.

The 2011 RDSGEIS guides the operator to conduct a five-part analysis:

> *The evaluation criteria should include (1) impact to the environment caused by the additive product if it remains in the environment, (2) the toxicity and mobility of the available alternatives, (3) persistence in the environment, (4) effectiveness of the available alternative to achieve desired results in the engineered fluid system, and (5) feasibility of implementing the alternative.*[137]

However the 2011 RDSGEIS does not instruct the operator on what is required if any part of the five-part analysis has an unacceptable outcome, nor does the NYCRR. For example, if an operator proposes a chemical additive that is known to impact the environment and be persistent if it remains in the environment, but the operator proposes no other alternative, or states that this is the only chemical that will be effective for its planned job, neither the RDSGEIS or the NYCRR prohibit the operator from using this chemical even if it is harmful.

As proposed, the NYCRR would still allow the use of a highly toxic chemical, as long as it was slightly less toxic than the most toxic chemical available. This is not best practice. Best practice would be to use the chemical with the lowest impact and risk, not just a slightly improved risk. Best practice would also be for NYS to develop a list of prohibited chemicals that pose an unacceptable risk to human health and the environment.

[137] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS concludes that it is not possible for hydraulic fracturing to contaminate groundwater, erroneously assuming that all wells will be flawlessly constructed and operated, and that no human error is possible that would put hydraulic fracturing additives in contact with groundwater, with the exception of a potential surface spill. The 2011 RDSGEIS concludes:

> *The regulatory discussion in Section 8.4 concludes that adequate well design prevents contact between fracturing fluids and fresh ground water sources, and text in Chapter 6 along with Appendix 11 on subsurface fluid mobility explain why ground water contamination by migration of fracturing fluid is not a reasonably foreseeable impact.*[138]

The 2011 RDSGEIS should be revised to clarify that groundwater contamination by hydraulic fracturing fluids is a reasonably foreseeable impact that requires mitigation. Well construction failures, engineering design flaws, human error, mechanical malfunctions, and chemical spills all are reasonably foreseeable events, and have occurred at Marcellus Shale operations in Pennsylvania.[139] Additionally, Dr. Myers identifies the potential long-term contaminant transport through conductive faults, natural fractures, and advective transport.[140]

Groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[141] PADEP inspectors *"…discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County.*"[142] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[143]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[144]

In May 2011, PADEP fined Chesapeake Energy Corporation $1,088,000 for violations related to natural gas drilling activities that contaminated private water supplies in Bradford County. PADEP issued a news release reporting:

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[138] 2011 NYSDEC, RDSGEIS, Page 8-29.

[139] DEP Investigating Lycoming County Fracking Fluid Spill at XTO Energy Marcellus Well, November 22, 2010, available at http://www.portal. state.pa.us/portal/server.pt/community/newsroom/

14287?id=15315&typeid=1

[140] Dr. Tom Myers, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

[141] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[142] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[143] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[144] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

> *DEP determined that because of improper well casing and cementing in shallow zones, natural gas from non-shale shallow gas formations had experienced localized migration into groundwater and contaminated 16 families' drinking water supplies.*[145]

If HVHF treatments are conducted in poorly constructed wells, there exists a potential for groundwater contamination. Therefore, as NYSDEC recommends, well construction must be robust, and the use of safe HVHF treatment additives provides any extra layer of protection in the event that human error or mechanical malfunction create a pathway for such additives to reach groundwater. Reducing the toxicity of hydraulic fracturing additives by listing prohibited additives mitigates the impact of both surface and groundwater pollution if it occurs.

Recommendation No. 37: NYSDEC should develop a list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2009 DSGEIS Section 5.3[146] stated that NYSDEC collected compositional information from chemical suppliers and service companies on many of the additives proposed for use in shale fracture treatments. NYSDEC reported partial compositional data on 197 products and complete compositional data on 152 products. Tables 5.3-5.7 provided lists of chemicals proposed for use in fracture treatments, and Section 5.4.3.1 described the potential health impacts of categories of chemicals. Yet the 2009 DSGEIS did not arrive at any recommendation or conclusion about which fracture treatment additives are acceptable for use in NYS and which are not. This problem persists in the 2011 RDSGEIS.

Chapter 5 of the 2011 RDSGEIS explains that NYSDOH reviewed information on 322 unique chemicals present in 235 products proposed for hydraulic fracturing of shale formations in New York and categorized them into chemical classes, but did not develop any recommendations for prohibiting specific HF additives. The 2011 RDSGEIS merely concludes that the 322 unique chemicals studied did not identify any potential exposure situations that are qualitatively different from those addressed in the 1992 GEIS.[147] This conclusion has little significance, since the 1992 GEIS did not establish any criteria for limiting or prohibiting HF chemical additives (i.e., for mitigating potential significant adverse impacts from exposure to these additives). For example, Dr. Miller points out that acrylonitrile and acrylamide are listed, and known to be carcinogenic and quite toxic, but fairly short lived in an aqueous environment.[148] As proposed, NYSDEC would allow these carcinogenic, toxic chemicals to be used, unless industry proposes a less-harmful chemical. The appropriate step for NYS would be to add acrylonitrile and acrylamide, among other chemical that pose a risk to human health or the environment, to the list of prohibited chemicals in NYS.

[145] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[146] 2009 NYSDEC, DSGEIS, Page 5-34.

[147] 2011 NYSDEC, RDSGEIS, Page 8-29.

[148] Dr. Glenn Miller, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

Although the percentage of hydraulic fracturing fluid that is composed of chemicals may be small—typically 0.5 to 2 percent of the total volume required for a Marcellus Shale hydraulic fracture stimulation—the absolute volume of chemicals used is very large. A typical Marcellus Shale well may require the use of more than five million gallons of freshwater for drilling and hydraulic fracturing. A five million gallon hydraulic fracture treatment would require approximately 25,000 to 100,000 gallons of hydraulic fracturing chemicals per well at a chemical additive dosage of 0.5 to 2 percent. Some of these chemicals are toxic, including known or possible human carcinogens, chemicals regulated under the Safe Drinking Water Act due to their risks to human health, and chemicals regulated under the Clean Air Act as hazardous air pollutants.[149]

Recommendation No. 38: The SGEIS should do more than just list chemicals proposed by industry for HVHF operations and describe their toxicity; the SGEIS should identify chemicals that should be prohibited or used with limitations to protect human health and the environment.

Additionally, the 2011 RDSGEIS includes a process for reviewing chemicals proposed by industry that appears to have little value or scientific rigor.

> *For every well permit application the Department would require, as part of the EAF Addendum, identification of additive products, by product name and purpose/type, and proposed percent by weight of water, proppants and each additive. This would allow the Department to determine whether the proposed fracturing fluid is water-based and generally similar to the fluid represented by Figures 5.3, 5.4, and 5.5.*[150]

Figures 5.3, 5.4, and 5.5 in the 2011 RDSGEIS are merely pie charts showing example compositions from previous Fayetteville and Marcellus Shale HVHF jobs. The 2011 RDSGEIS does not include a scientific analysis of the proposed HVHF compositions to verify if these mixtures are optimal. Therefore, there is little scientific value in having NYSDEC staff compare an operator's proposed HVHF composition to these figures, because NYSDEC has not even completed the fundamental scientific analysis to verify whether these proposed treatment compositions are protective of human health and the environment and whether the figures are a suitable yardstick.

The 2011 RDSGEIS proposes to require industry to submit a Material Safety Data Sheet (MSDS) for every new product that is not currently listed by NYSDEC in Chapter 5 of the 2011 RDSGEIS. NYSDEC explains that the MSDS will provide it with more information on the proposed chemical, but does not institute a plan for taking action to limit or prohibit hazardous chemical use based on a review of that MSDS. Instead, the 2011 RDSGEIS appears to propose that NYSDEC will just collect MSDS information and take no action, other than to accept the chemicals selected by the operator and add the MSDS to NYSDEC's file system.

> *The Department would also require the submittal of an MSDS for every additive product proposed for use, unless the MSDS for a particular product is already on file as a result of the disclosure provided during the preparation process of this SGEIS (as discussed in Chapter 5) or during the application process for a previous well permit. Submittal of product MSDSs would provide the Department with the identities, properties and effects of the hazardous chemical constituents within each additive proposed for use.*[151]

[149] United States House of Representatives, Committee on Energy and Commerce, Minority Staff, Chemicals Used in Hydraulic Fracturing, April 2011.

[150] 2011 NYSDEC, RDSGEIS, Page 8-30.

[151] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS goes on to say that NYSDEC staff will verify, by reviewing the well completion form, that the chemicals proposed by industry in a permit application (with no limitations or prohibitions by NYSDEC) were actually the same chemicals used on the HVHF job.

> *In addition to the above requirements for well permit applications, the Department would continue its practice of requiring hydraulic fracturing information, including identification of materials and volumes of materials utilized, on the well completion report which is required, in accordance with 6 NYCRR §554.7, to be submitted to the Department within 30 days after the completion of any well. This requirement can be utilized by Department staff to verify that only those additive products proposed at the time of application, or subsequently proposed and approved prior to use, were utilized in a given high-volume hydraulic fracturing operation.*[152]

The proposed review process holds little scientific or audit value, since NYSDEC is not limiting chemicals in the initial application. It is insufficient to bind industry to use specific chemicals at the tail end of the permitting process, when industry can propose any chemical for use on the front-end.

However, the proposed chemical audit review process would have great value if NYSDEC limited or prohibited chemical use in the initial application. In that case, a post-HVHF review process would be valuable to verify that prohibited chemicals were not used.

There are several international models in place that NYSDEC could consider using to develop a prohibited chemical list, or to develop an approved list of chemical, or both. Below is a short summary of three models that could be considered: (1) the Oslo-Paris Convention (OSPAR) list of environmentally friendly chemicals (chemicals considered to Pose Little Or No Risk (PLONOR) for the oil and gas industry); (2) Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands; and (3) the Norwegian Pollution Control Authority chemical coding system for the oil and gas industry. These governmental entities prohibit use of chemicals that have harmful characteristics, such as: low biodegradability; high bioaccumulation potential; high acute toxicity; and detrimental mutagenic or reproductive effects.

OSPAR PLONOR: Certain European governmental entities have developed a list of environmentally friendly chemicals. Under the Oslo-Paris Convention (OSPAR)[153] a list of chemicals that were considered to Pose Little Or No Risk (PLONOR) to the marine environment was developed for use in drilling and stimulation treatments. The PLONOR list was initially developed in early 2000 and has been amended several times to add and de-list chemicals. The PLONOR list has been very effective in reducing chemical pollution from offshore operations, and use of the PLONOR list has expanded to onshore oil and gas operations and to other industrial sectors. HCLCC is not recommending that NYS adopt the PLONOR list without review; instead, HCLLC is recommending that NYSDEC consider a process similar to OSPAR's system to develop a list of hydraulic fracturing treatment additives that would pose little or no risk to human health or the environment if the chemicals spilled, leaked, or were improperly disposed, or, in the alternative, consider developing a list of chemicals to be prohibited from use in hydraulic fracturing operations.

[152] 2011 NYSDEC, RDSGEIS, Page 8-31.

[153] The Convention for the Protection of the Marine Environment of the North-East Atlantic (the "OSPAR Convention") was opened for signature at the Ministerial Meeting of the former Oslo and Paris Commissions in Paris on 22 September 1992. The Convention entered into force on 25 March 1998. It has been ratified by Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, Netherlands, Norway, Portugal, Sweden, Switzerland and the United Kingdom and approved by the European Community and Spain.

The OSPAR process is straight forward: the establishment of criteria for inclusion of substances on the PLONOR list. Industry has the burden of proof to provide scientific and technical data to support listing of a chemical as PLONOR—i.e., industry must prove the chemical poses little or no risk. The OSPAR Commission reviews the data and makes the final listing determination. The Commission also can remove chemicals from the PLONOR list if new information comes to light warranting a de-listing. A current list of PLONOR chemicals can be found at the OSPAR website.[154]

C-NLOPB Guidelines: The Canada-Newfoundland and Labrador Offshore Petroleum Board has developed guidelines that industry must follow to select less harmful chemicals used in their offshore oil and gas operations.[155] Industry operators must demonstrate that they have incorporated a chemical selection process in their management system that conforms to the guidelines, and the Board has the ability to audit industry compliance. The guidelines are reviewed at least once every five years to ensure that gains in scientific and technical knowledge are incorporated, and more frequent reviews may be initiated if significant risks are identified. The C-NLOPB Guidelines rely in part on the PLONOR list, but also establish specific requirements for hazard and risk assessment.

The Norwegian Pollution Control Authority has developed a chemical coding system to prohibit use of harmful and toxic chemicals in the Norwegian petroleum industry. The Norwegian Pollution Control Authority system categorizes chemicals by color, using the colors: black, red, yellow and green. Black chemicals are the most hazardous, followed by red, then yellow. Green chemicals are those listed on the PLONOR list.

Black: chemicals on the OSPAR List of Chemicals for Priority Action, chemicals on the Norwegian Pollution Control Authority prioritized list (White Paper No. 21 (2004-2005)), and chemicals in the following categories, characterized by certain ecotoxicological properties:

- Substances that have both a low biodegradability (BOD_{28}<20%) and a high bioaccumulation potential (log P_{OW}•5);
- Substances that have both a low biodegradability (BOD_{28}<20%) and a high acute toxicity (EC_{50} or LC_{50}•10 mg/l); and
- Substances that are detrimental in a mutagenic or reproductive way.

Red: chemicals in the following categories, characterized by certain ecotoxicological properties:

- Inorganic substances that are acutely toxic (EC_{50} or LC_{50}•1 mg/l);
- Organic substances with a low biodegradability (BOD_{28}<20%);
- Substances that meet two of the three following criteria:
  - Biodegradability equivalent to BOD_{28}<60%;
  - Bioaccumulation potential equivalent to log P_{OW}•3 and molecular weight < 700; or
  - Acute toxicity of EC_{50} or LC_{50}•10 mg/l.[156]

[154] OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic, OSPAR List of Substances/Preparations Used and Discharged Offshore Which Are Considered to Pose Little or No Risk to the Environment (PLONOR), Reference Number: 2004-10, 2008 Update, available at: http://www.klif.no/arbeidsomr/petroleum/dokumenter/plonor2008.pdf

[155] The Canada-Newfoundland and Labrador Offshore Petroleum Board, Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands, April 2009, available at http://publications.gc.ca/collections/collection_2009/one-neb/NE23-151-2009E.pdf.

[156] Regulations Relating to Conduct of Activities in the Petroleum Activities (The Activities Regulations), § 56b. The latest update of this list can be found on OSPAR's website under the Offshore Oil and Gas Industry, Decisions, Recommendations and other Agreements.

Green: chemicals on the OSPAR PLONOR list (chemicals considered to Pose Little Or No Risk to the marine environment).

Yellow: chemicals that are not categorized as Green, Black or Red.

Recommendation No. 39: The SGEIS and the NYCRR should include a more rigorous technical and scientific review process to examine newly proposed fracture treatment additives to ensure they are protective of human health and the environment. In addition to a list of prohibited chemicals, NYSDEC should develop a list of recommended/approved fracture treatment additives that have been scientifically and technically reviewed by NYSDEC and NYSDOH and confirmed to pose little or no risk to human health or the environment. This list could be provided to industry for immediate use and would provide industry with a simplified list of chemicals that have already been determined to pose the least risk.

Any chemical not found on this list, or on the list of prohibited chemicals, could be proposed by industry for future use, but would be subject to an in-depth scientific and technical justification and risk assessment review process before being added to the approved chemical list for NYS.

No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment. Industry should bear the burden of proof of demonstrating to NYSDEC and NYSDOH that the chemical is safe. The technical and scientific review and approval process to examine newly proposed fracture treatment additives should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This more rigorous technical and scientific review process should apply to all hydraulic fracture treatments, not just HVHF treatments.

12. Drilling Mud Composition and Disposal

Background: In 2009, HCLLC recommended that the NYCRR be revised to: acknowledge and mitigate drilling mud pollution impacts; minimize drilling waste generation; limit heavy metal and NORM content; and establish best practices for the collection, treatment and disposal of drilling waste.

NYCRR Proposed Revisions: NYSDEC proactively responded to scientific and technical information provided through the public input process, revising the NYCRR to recognize that drilling muds are polluting fluids. NYSDEC removed the existing sentence at 6 NYCRR § 554.1(c)(1) that says "drilling muds are not considered to be polluting fluids." This is an important and positive change in the regulations.

However, additional work is still needed in the proposed amendments to the NYCRR to define what types of drilling muds should be used at various depths in constructing a well. NYCRR should also be amended to include best practices for how those drilling muds should be properly handled and disposed.

In January 2011, NYS consultant, Alpha Geoscience complimented HCLLC for its recommendations on drilling mud composition and disposal and agreed that additional mitigation was warranted. Alpha Geoscience wrote: [157]

> *Harvey Consulting has commented on the need for regulation revisions to specifically address drilling mud and drilling waste. The report states "New York State regulations should be revised to acknowledge and mitigate drilling mud pollution impacts, minimize drilling waste generation, limit heavy metal and NORM (Naturally Occurring Radioactive Material) content, and establish best practices for collection, treatment and disposal of drilling waste.*
>
> *Current NYS regulation 6 NYCRR §554.1(c)(1) states that drilling muds are not considered polluting fluids. The 1992 GEIS allows drill cuttings to be buried onsite, and the dSGEIS does not address the potential impact. Drilling muds commonly contain barite which contains mercury (1-10 ppm) (www.fossil.energy.gov) and may also contain cadmium. NYSDEC has not set limits on the heavy metal content of drilling mud, and New York State regulations do not address how to dispose of drill cuttings containing NORM.*
>
> *Harvey Consulting's recommended best management practice for most applications includes a combination of waste minimization, using low impact additives, collecting waste in a closed-loop system, pumping waste to a cuttings reinjection unit, and disposing the waste into a disposal well by deep well injection. Harvey Consulting suggests NYSDEC should thoroughly analyze each situation and location to develop the best site-specific best management practices.*
>
> *Harvey Consulting's comments concerning the composition and handling of drilling mud and drilling waste appear to have some merit. Per 6 NYCRR §554.1 (C)(1) drilling muds are not considered polluting fluids, however the presence of mercury and cadmium in barite composed drilling muds may be cause for concern given the quantity of drilling mud that would be required to drill each well.*

[157] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 7-9.

> *NYSDEC regulations do not clearly define the treatment or disposal of drilling waste and any best management practices concerning their handling, and/or recycling are not clearly outlined in the dSGEIS as documented by Harvey Consulting. Section 5.13 of the dSGEIS covers waste disposal, however it is general in its scope and does not outline any best management practices concerning the recycling, treatment, or disposal of drilling waste.*
>
> *Harvey Consulting's review recommends that the dSGEIS include best management practices concerning the type and handling of drilling mud and the subsequent waste byproducts. It suggests that NYSDEC should determine which drilling fluid composition and disposal methods are best practices for various scenarios.* ***Alpha agrees that the proposed measures seem reasonable and would serve to protect the public, environment, and the drilling applicant*** *[emphasis added].*

2011 RDSGEIS: The 2011 RDSGEIS explains that drilling operators propose to drill through protected groundwater zones using compressed air or Water-Based Muds (WBM).

> *The vertical portion of each well, including the portion that is drilled through any fresh water aquifers, will typically be drilled using either compressed air or freshwater mud as the drilling fluid.*[158]

The use of compressed air and WBM for drilling though the protected groundwater zones is best practice, as long as NYCRR also sets limits on the type of additives that can be mixed in the WBM formulation. WBM additives used when drilling through the protected groundwater zones should be non-toxic.

The 2011 RDSGEIS' use of the term "typically" indicates that use of compressed air and WBM for drilling though the protected groundwater zones may only occur a portion of the time. This is a best practice that should be implemented each time a well is drilled through protected groundwater zones.

While the 2011 RDSGEIS documents industry's position that it "typically" will use compressed air and WBM for the protection of groundwater, NYSDEC should *require* that practice and ensure that the requirement is codified in NYCRR. The proposed amendments to the NYCRR do not limit the types of drilling muds that can be used while drilling through protected groundwater zones. NYCRR should be revised to clearly prohibit the use of Oil-Based Muds (OBM) and Synthetic-Based Muds (SBM) drilling through protected groundwater zones and to limit additives used in the WBM to those that are non-toxic.

OBM contain diesel fuel or other hydrocarbons. SBM use synthetic oil. SBM are less harmful than OBM, but still contain materials that are toxic, bio-accumulate when discharged into water, and do not bio-degrade. For example, European nations prohibit the discharge of SBM to offshore waters, and prohibit their use when drilling through protected waters.[159] SBM are not approved by USEPA or Department of Energy for discharge offshore because they exceed USEPA's effluent limit guidelines.[160] The 2011 RDSGEIS incorrectly describes SBM as *"food-grade"* and *"environmentally friendly."*[161]

[158] 2011 NYSDEC, RDSGEIS, Page 5-32.

[159] Jonathan Wills, M.A., Ph.D., M.Inst.Pet., for Ekologicheskaya Vahkta Sakhalina, Muddied Waters A Survey of Offshore Oilfield Drilling Wastes and Disposal Techniques to Reduce the Ecological Impact of Sea Dumping, May 25, 2000.

[160] http://web.ead.anl.gov/dwm/techdesc/discharge/index.cfm.

[161] 2011 NYSDEC, RDSGEIS, Page 5-32.

Recommendation No. 40: 6 NYCRR § 554.1(c)(1) should be revised to limit the types of drilling muds that can be used while drilling through subsurface formations that contain protected groundwater. Drilling muds should be limited to Water-Based Muds (WBM) or drilling with air. Any additives required for safe drilling through the protected groundwater interval with WBM should be limited to additives that are bio-degradable, are non-toxic, and do not bio-accumulate. The SGEIS should also include this requirement as a mitigating measure.

Neither the 2011 RDSGEIS nor the proposed amendments to the NYCRR instruct the operator on how to properly dispose of drilling fluids. NYCRR requires a disposal plan and that drilling fluids be removed from the drillsite within 45 days; however, 6 NYCRR § 554.1(c)(1) does not provide specific instructions or criteria for acceptable drilling mud disposal plans. This problem was identified by HCLLC in 2009, and is still unresolved.

This problem is magnified in light of new language in the 2011 RDSGEIS that appears to contemplate allowing drilling muds to be spread on non-active agricultural fields and other soils. The 2011 RDSGEIS includes a discussion on proposed Agricultural District requirements. One of the requirements discussed is for "spent drilling muds to be removed from active agricultural fields." [162] The RDSGEIS is silent on provisions for non-active agricultural fields and other soils, and it is unclear what NYSDEC has planned for drilling mud disposal. NYSDEC should clarify its intentions in regards to spreading drilling muds.

The 2011 RDSGEIS correctly notes that drilling mud can be reconditioned and used at more than one well,[163] but it must eventually be disposed. Drilling muds may contain mercury, metals, NORM, oils, and other contaminates. This is especially true for Marcellus Shale operations where naturally occurring radioactive material is present in the shale drill cuttings and mud mixture. Therefore, drilling muds require proper handling and disposal. [164]

Solid waste management regulations at 6 NYCRR Chapter IV, Subchapter B (Solid Waste) provide the authority by which the state (through the Division of Solid and Hazardous Materials) establishes standards and criteria for solid waste management operations, including landfills and land application. However, the RDSGEIS is unclear on what NYSDEC has deemed to be the best management practices for handling drilling waste. A recent U.S. Department of Energy review of NYSDEC's drilling waste disposal regulations concluded:

> *"The [NYS]* ***DEC has developed no regulations, policies, or guidelines*** *governing slurry injection, subsurface injection, or annular disposal of drilling wastes and reserve-pit wastes [emphasis added]."*[165]

NYSDEC has not established regulations to minimize the generation of drilling waste (e.g. reuse, recycle), or established limits on the heavy metal content of drilling mud additives.

Regulations at 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on drilling fluid handling and disposal. Questions that need to be addressed include: Where will drilling waste be taken for treatment and disposal? What tests will be run to characterize the waste stream for proper handling,

[162] 2011 NYSDEC, RDSGEIS, Page 7-145.

[163] 2011 NYSDEC, RDSGEIS, Page 5-32.

[164] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[165] U.S. Department of Energy, Drilling Waste Management Information System, http://web.ead.anl.gov/dwm/regs/state/newyork/index.cfm.

treatment, and disposal? Does the treatment capacity exist to handle this incremental waste in NYS? If so, where are the treatment facilities located? What types of treatments will be completed? What is the ultimate disposal location for the treatment byproducts?

Recommendation No. 41: 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on the best practices for drilling mud handling and disposal. The SGEIS should also provide specific instructions on the best practices for drilling mud handling and disposal as a mitigating measure. See Chapter 13 of this report for additional recommended disposal solutions.

13. Reserve Pit Use & Drill Cuttings Disposal

Background: In 2009, HCLLC recommended that NYSDEC adopt regulations requiring closed-loop tank systems as best practice, instead of the use of temporary reserve pits to handle and store drill muds and cuttings, unless the operator demonstrates that closed-loop tank systems are not technically feasible. Additionally, HCLLC recommended that if temporary reserve pits are used, NYSDEC should adopt regulations that: require impermeable, chemical resistant liner material; limit the types of chemicals stored to those compatible with the liner material; require wildlife protection design standards; and establish firm removal and restoration requirements when drilling was completed. HCLLC recommended that cuttings not be buried onsite, and that waste be removed from the drilling location and properly disposed at an approved waste disposal facility capable of handling the quantity and type of waste generated.

HCLLC recommended that NYS consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a properly designed, approved subsurface disposal well. Additionally, HCLLC recommended that if reserve pits are determined to be the only technically feasible option for temporary waste storage, that storage of drilling waste be limited to un-contaminated drill cuttings, drilled using compressed air or water based-muds with non-toxic additives.

2011 RDSGEIS: The 2011 RDSGEIS recommends closed-loop tank systems as best practice in some circumstances, but in other circumstances defaults to the use of reserve pits, without demonstrating that reserve pits are environmentally preferable.

The RDSGEIS requires a closed-loop tank system for horizontal drilling operations in the Marcellus Shale that do not have an acceptable acid rock drainage (ARD) mitigation plan[166] for on-site cuttings burial; and drill cuttings that are coated with Synthetic-Based Muds (SBM) and Oil-Based Muds (OBM). In all other cases, the RDSGEIS proposes the use of reserve pits.

> *The revised draft SGEIS proposes to require, pursuant to permit conditions and/or regulation, that a closed-loop tank system be used instead of a reserve pit to manage drilling fluids and cuttings for:*
>
> - *Horizontal drilling in the Marcellus Shale without an acceptable acid rock drainage (ARD) mitigation plan for on-site cuttings burial; and*
> - *cuttings that, because of the drilling fluid composition used must be disposed off-site, including at a landfill.* [167]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 56 requires the operator to provide NYSDEC with an acid rock drainage mitigation plan if NYSDEC requests the plan. However, there is no specific criteria established to define what constitutes and acceptable acid rock drainage mitigation plan.

[166] 2011 NYSDEC, RDSGEIS, Page 7-67.

[167] 2011 NYSDEC, RDSGEIS, Page 1-13.

Yet, the USGS recommends against onsite disposal because of the potential risk posed:

> *Onsite burial of drill cuttings at shale-gas development sites, which is allowable under the dSGEIS if oil-based drilling mud is not used, should be carefully considered. According to Lash and Engelder (2008), pyrite is abundant in the high-TOC basal intervals of the Marcellus Shale. Oxidation and leaching of pyritic shale produces and acidic, metals-rich discharge commonly referred to as AMD (Acid Mine Discharge). A multi-horizontal well site will generate 100 to 500 times the volume of AMD-producing pyritic shale cutting than that generated at a single-vertical well site.* ***If these pyritic shale drill cuttings are left onsite, the potential for future surface-water and groundwater contamination is significant – removal and disposal of all cuttings at an approved landfill would be the preferred approach*** *[emphasis added].*[168]

The RDSGEIS proposal to use reserve pits is internally inconsistent with the RDSGEIS' conclusion that closed-loop tank systems are environmentally preferable for the following reasons:

> *Depending on the configuration and design of a closed-loop tank system use of such a system can offer the following advantages:*
>
> - *Eliminates the time and expense associated with reserve pit construction and reclamation;*
> - *Reduces the surface disturbance associated with the well pad;*
> - *Reduces the amount of water and mud additives required as a result of re-circulation of drilling mud;*
> - *Lowers mud replacement costs by capturing and re-circulating drilling mud;*
> - *Reduces the wastes associated with drilling by separating additional drilling mud from the cuttings; and*
> - *Reduces expenses and truck traffic associated with transporting drilling waste due to the reduced volume of the waste.*[169]

Additionally, the 2011 RDSGEIS explains the environmental risks of reserve pits:

> ***Pit leakage or failure could also involve well fluids****. These issues are discussed in Chapters 8 and 9 of the 1992 GEIS, but are acknowledged here with respect to unique aspects of the proposed multi-well development method. The conclusions regarding pit construction standards and liner specifications presented in the 1992 GEIS were largely based upon the short duration of a pit's use.* ***The greater intensity and duration of surface activities associated with well pads with multiple wells increases the potential for an accidental spill, pit leak or pit failure if engineering controls and other mitigation measures are not sufficient****. Concerns are heightened if on-site pits for*

[168] Testimony of John H. Williams, Ground-Water Specialist, U.S. Geological Survey, The Council of the City of New York Committee on Environmental Protection, Public Hearing, Draft Supplemental Generic Environmental Impact Statement Relating to Drilling for Natural Gas in New York State Using Horizontal Drilling and High-Volume Hydraulic Fracturing, October 23, 2009, Page 2.

[169] 2011 NYSDEC, RDSGEIS, Page 5-39.

> *handling drilling fluids are located in primary and principal aquifer areas, or are constructed on the filled portion of a cut-and-filled well pad [emphasis added].*[170]
>
> *As explained in Chapter 5, the total volume of drill cuttings produced from drilling a horizontal well may be about 40% greater than that for a conventional, vertical well to the same target depth. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad.* ***The potential water resources impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations would arise from the retention of cuttings during drilling, necessitating a larger reserve pit that may be present for a longer period of time, unless the cuttings are directed into tanks as part of a closed-loop tank system****[emphasis added].*[171]

The use of close-loop drilling waste handling system is a best practice. For example, New Mexico requires the use of closed-loop drilling systems.[172]

Recommendation No. 42: The SGEIS and NYCRR should be revised to prohibit reserve pit use for Marcellus Shale drilling operations, and instead require closed-loop tank systems to collect drill cuttings and transport them to waste disposal facilities. NYCRR should make reserve pit use the exception, allowing it only in cases where closed-loop tank systems are determined to be technically infeasible. If reserve pits are determined to be the only technically feasible option, storage of drilling waste should be limited to un-contaminated drill cuttings from the section of the well drilled using compressed air or water based-muds with non-toxic additives. These best practices for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Of even greater concern is the RDSGEIS' proposal to allow drill cuttings to be buried onsite in some cases. Marcellus Shale cuttings contain Naturally Occurring Radioactive Materials (NORM) and are coated with drilling muds, including Water-Based Mud (WBM). The Marcellus Shale is considered a "highly radioactive" shale,[173] and its drill cuttings may require special hazardous waste handling and treatment. While the RDSGEIS proposes to allow on-site burial only of drill cuttings that were created by air drilling or WBM drilling operations, WBM may contain mercury, metals, and other contaminants.[174]

> *The Department has determined that drill cuttings are solid wastes, specifically construction and demolition debris, under the State's regulatory system. Therefore,* ***the Department would allow disposal of cuttings from drilling processes which utilize only air and/or water on-site****, at construction and demolition (C&D) debris landfills, or at municipal solid waste (MSW) landfills, while cuttings from processes which utilize any oil-based or polymer-based products could only be disposed of at MSW landfills [emphasis added].*[175]

[170] 2011 NYSDEC, RDSGEIS, Page 6-16.

[171] 2011 NYSDEC, RDSGEIS, Page 6-65.

[172] New Mexico, Energy, Minerals and Natural Resources Department, Oil Conservation Division, Regulations at Title 19, Chapter 15, Part 17.

[173] Hill, D.G., Lombardi, T.E. and Martin, J.P., Fractured Shale Gas Potential in New York, 2002, p.8.

[174] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[175] 2011 NYSDEC, RDSGEIS, Page 1-13.

The proposed revisions to NYCRR would require the reserve pit liner to be ripped and perforated as part of the onsite burial process (6 NYCRR § 560.7(c)); therefore, contaminated drill cuttings would be in direct contact with soils and surface waters.

While the RDSGEIS generally takes the position that WBM-coated cuttings can be stored in reserve pits and buried onsite, in some cases it waivers. It is not clear what additional limitations may be applied to WBM-coated drill-cuttings disposal. NYSDEC recognizes that onsite burial of chemical additives included in WBM may not be prudent. However, the RDSGEIS does not spell out criteria for determining what types of WBM-coated cuttings may and may not be stored and buried in reserve pits. The RDSGEIS proposes this decision be left to a later NYSDEC consultation process.

An example of how the RDSGEIS deviates from its general position that WBM-coated cuttings can be stored in reserve pits and buried onsite is as follows:

> *Supplementary permit conditions pertaining to the management of drill cuttings from high-volume hydraulic fracturing* ***<u>require consultation with the Department's Division of Materials Management for the disposal of any cuttings associated with water-based mud-drilling and any pit liner associated with water-based or brine-based mud-drilling where the water-based or brine-based mud contains chemical additives.</u>*** *Supplemental permit conditions also dictate that any cuttings required to be disposed of off-site, including at a landfill, be managed on-site within a closed-loop tank system rather than a reserve pit [emphasis added].*[176]

This uncertain position about what to do with WBM-coated drill cuttings is perpetuated in the proposed revisions to NYCRR at 6 NYCRR § 560.7(c):

> *Consultation with the department's Division of Materials Management (DMM) is required prior to disposal of any cuttings associated with water-based mud-drilling and pit liner associated with water-based mud-drilling where the water-based mud contains chemical additives.*

All WBM contains chemical additives. NYCRR must be clear on which chemical additives would trigger the use of closed-loop tanks and prohibit drill cuttings burial onsite.

Recommendation No. 43: The SGEIS and NYCRR should be clear about how WBM-coated drill cuttings will be handled and should not leave this unresolved. The standards for handling WBM-coated drill cuttings should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Additionally, it is inefficient from a logistics and energy use standpoint to construct a reserve pit for the temporary storage of drill cuttings, and then remove this pit at a later time. It is substantially more efficient to use a closed-loop tank system to collect the drill cuttings, because the cuttings can be directly transported to a waste handling facility. The RDSGEIS agrees with the efficiencies gained through closed-loop tank systems, but incongruously does not recommend them in all cases.

[176] 2011 NYSDEC, RDSGEIS, Page 7-67.

> *The 1992 GEIS discusses the use of reserve pits and tanks, either alone or in conjunction with one another, to contain the cuttings and fluids associated with the drilling process. Both systems result in complete capture of the fluids and cuttings; however the use of tanks in* ***closed-loop tank systems facilitates off-site disposal of wastes while more efficiently utilizing drilling fluid and providing additional insurance against environmental releases*** *[emphasis added].*[177]
>
> *The design and configuration of closed-loop tank systems will vary from operator to operator, but all such systems contain drilling fluids and cuttings in a series of containers, thereby eliminating the need for a reserve pit….the objective is to fully contain the cuttings and fluids in such a manner as to prevent direct contact with the ground surface or the need to construct a lined reserve pit.*[178]

NYSDEC's proposal for onsite burial of contaminated drill cuttings becomes even more paradoxical when the RDSGEIS concludes that operators have not proposed onsite burial of drill cuttings.

> ***Operators have not proposed on-site burial of mud-drilled cuttings****, which would be equivalent to burial or direct ground discharge of the drilling mud itself. Contaminants in the mud or in contact with the liner if buried on-site could adversely impact soil or leach into shallow groundwater [emphasis added].*[179]

A portion of the well drilled will generate cuttings that do not contain NORM. However, as identified in the RDSGEIS, the Marcellus contains NORM and cuttings drilled during this section of the well would require special handling and disposal.

Recommendation No. 44: The SGEIS and NYCRR should prohibit the onsite burial of drill cuttings. If onsite burial is permitted, it should be limited to cuttings that do not have any NORM and are not coated with drill muds containing mercury, heavy metals, and other chemical additives.

Cuttings Reinjection (CRI) Technology, also referred to as "grind-and-inject technology" is commonly used by industry as a best practice to avoid the need for long-term onsite burial of drill cuttings. CRI technology converts drill cuttings into a slurry that can be injected into a subsurface disposal well. CRI also provides a waste disposal method for used drilling mud, because mud can be used in the slurry formulation to reduce supplemental water needs. Currently, NYS does not have sufficient waste disposal wells to handle the anticipated Marcellus Shale drilling waste volume. Either NYS would need to rely on permitted waste handling capacity at wells out of state, or would need to permit and drill wells to meet that need if there are geologically, hydrologically, and otherwise appropriate locations for such wells in NYS.

For example, CRI is commonly used in Alaska as a best practice to avoid use of long-term reserve pit use and surface burial of contaminated drill cuttings. Waste is collected, ground into a slurry, and injected into a subsurface disposal well.[180] If an injection well is not available at a well location, operators have

[177] 2011 NYSDEC, RDSGEIS, Page 5-37.

[178] 2011 NYSDEC, RDSGEIS, Page 5-37.

[179] 2011 NYSDEC, RDSGEIS, Page 6-66.

[180] BP Exploration (Alaska), Inc., ARCO Alaska, Inc. and ConocoPhillips, Inc. have published numerous technical papers on grind and injection technology, and the success of disposal wells as a pollution prevention measure in the SPE trade journals, and at industry conferences.

collected wastes and transported them back to an injection well location. Operators that do not have their own waste handling facilities or disposal wells typically negotiate an agreement with another operator or a service provider to use its disposal facilities. As a result of this best practice implementation in Alaska, DOE reports there are 58 active Class II-D (disposal) wells and six Class I wells in Alaska.[181]

NYS would need to permit construction of a sufficient number of Class I and Class II injection wells to ensure that there was sufficient capacity for the types and amounts of waste generated.

In addition to the environmental mitigation benefit, CRI technology reduces future liability for industry operators, and has been determined to be an environmentally-appropriate method for handling drilling waste containing NORM by both Shell and Chevron.[182]

Halliburton, an industry service provider, agrees that CRI technology makes business and environmental sense as compared to long-term drilling waste burial at the surface.

> *While it is true that new technology comes with a price tag, and much of the technology used in drilling waste management has been introduced in the last 10 years, many technologies now available to operators* ***<u>are clearly cost effective when the entire well construction cost is evaluated</u>****.*
>
> *The cost of making a mistake and having either an expensive remediation project or a potential liability nearly always significantly outweighs the cost of a good preventative drilling waste management program. Further, compliance with current environmental regulations does not always guarantee immunity in the future…*
>
> *Numerous examples exist of industries having to clean up sites that were fully compliant with all regulations at the time the waste was generated and disposed of….*
>
> *The paper demonstrates that the correct application of these technologies combined with a holistic approach to drilling waste management and drilling fluid operations results in a net reduction in well construction costs and a reduction in the potential for environmental liability…*
>
> *… environmental compliance (whether internally or externally driven) is not the only reason to utilize these types of technologies and services [emphasis added].*[183]

International operators report favorable economics for eliminating exploration and production waste by deep well injection. For example, a 2001 Advantek International Corp. report concludes:

> *Downhole disposal of mud and cuttings waste through hydraulic fracturing provides a zero discharge solution and eliminates future cleanup liabilities…This downhole disposal technology has shown success <u>in both onshore and offshore drilling operations</u> and is*

[181] Puder, M.G., Bryson, B., Veil, J.A, Argonne National Laboratory, "Compendium of Regulatory Requirements Governing Underground Injection of Drilling Wastes," Prepared for the U.S. Department of Energy, February 2003, Page 17.

[182] Okorodudu, A., Akinbodunse, A., Linden, L., Chevron Nigeria Ltd, Anwuri, L., Shell Petroleum Development Co. Nigeria Ltd., Irrechukwu, D.O., Zagi, M.M., Nigeria Department of Petroleum Resources, Guerrero, H., M-I Swaco, "Feasibility Study of Cuttings-Injection Operation: A Case Study of the Niger Delta Basin," SPE Paper 98640, presented at the SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production in Abu Dhabi, U.A.E., April 2006,Page 2.

[183] Browing, K., Seaton, S., Halliburton Fluid Systems, "Drilling Waste Management: Case Histories Demonstrate that Effective Drilling Waste Management Can Reduce Overall Well-Construction Costs," SPE Paper 96775, presented at the 2005 SPE Annual Technical Conference and Exhibition in Dallas Texas, October 2005, Pages 1, 3, & 4

> *becoming a routine disposal option…It also offers favorable economics [emphasis added].*[184]

The U.S. Department of Energy (DOE) also advocates CRI technology:

> *Because wastes are injected deep into the earth below drinking water zones, proper slurry injection operations should pose lower environmental and health risks than more conventional surface disposal methods.*[185]

In 1990, the United States passed the Pollution Prevention Act, establishing a national policy that places priority on pollution prevention and specifies that disposal into the environment should only be allowed as a **last resort**:

> *The Congress hereby declares it to be the national policy of the United States that pollution should be prevented or reduced at the source whenever feasible; pollution that cannot be prevented should be recycled in an environmentally safe manner, whenever feasible; pollution that cannot be prevented or recycled should be treated in an environmentally safe manner whenever feasible; and **disposal or other release into the environment should be employed only as a last resort** and should be conducted in an environmentally safe manner[emphasis added]. "*[186]

Additionally, the amount of drill-cutting waste generated can be significant. If CRI technology is not used to dispose of this waste by deep well injection, than surface waste disposal sites will need to be utilized to handle this waste. The RDSGEIS estimates the amount of waste generated for each well:

> *For example, a vertical well with surface, intermediate and production casing drilled to a total depth of 7,000 feet produces approximately 154 cubic yards of cuttings, while a horizontally drilled well with the same casing program to the same target depth with an example 4,000-foot lateral section produces a total volume of approximately 217 cubic yards of cuttings (i.e., about 40% more). A multi-well site would produce approximately that volume of cuttings from each well.*[187]

Recommendation No. 45: NYS should consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a subsurface disposal well, and work with industry to permit a sufficient number of drilling waste disposal wells to safely meet this need. The use of Cuttings Reinjection (CRI) technology for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR, as an environmentally preferable option to onsite-disposal of drilling waste.

[184] Abou-Sayed, A., SPE, Advantek International, Guo, Q., SPE, Advantek International, "Design Considerations in Drill Cuttings Re-Injection Through Downhole Fracturing," IADC/SPE Paper 72308, Presented at the IADC/SPE Middle East Drilling Technology Meeting in Bahrain, October 2001, Page 1.

[185] Argonne National Laboratory, "An Introduction to Slurry Injection Technology for Disposal of Drilling Wastes," Publication prepared for the U.S. Department of Energy, September 2003, Page 2.

[186] Pollution Prevention Act of 1990, U.S. Code, Title 42, Public Health and Welfare, Chapter 133, Pollution Prevention.

[187] 2011 NYSDEC, RDSGEIS, Page 5-34.

14. HVHF Flowback Surface Impoundments at Drillsite

Background: In 2009, HCLLC recommended that the NYCRR require fracture fluid flowback be routed to onsite treatment systems for fracture fluid recycling and/or collected in closed-loop tanks for transportation to offsite treatment systems. Surface impoundments should not be used for fracture fluid flowback.

2011 RDSGEIS: The 2011 RDSGEIS made excellent revisions that address public concerns and are protective of human health and the environment by clearly prohibiting HVHF flowback waste impoundments at drillsites. The 2011 RDSGEIS recommends the use of closed-loop tank systems at the drillsites for collecting waste before transporting it to a treatment location, or recycling it for use on another well:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[188]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[189]

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.6(c)(27) specifically prohibit HVHF flowback from being directed to or stored in any on-site pit, and require covered watertight tanks to handle flowback at the drillsite. Furthermore, 6 NYCRR § 750-3.4(b) prohibits the issuance of a State Pollutant Discharge Elimination System (SPDES) permit without prior certification that HVHF flowback fluids will be not be directed to or stored in a pit or impoundment. Proposed regulations at 6 NYCRR § 560.3(a)(10)-(11) also require an operator to provide a description of the closed-loop tank system it will use and the number of receiving tanks it will employ for flowback water.

No further recommendations. The RDSGEIS includes the use of closed-loop tank systems, which is best available technology.

[188] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[189] 2011 NYSDEC, RDSGEIS, Page 1-12.

15. HVHF Flowback Centralized Surface Impoundments Off-Drillsite

Background: In 2009, HCLLC recommended that the NYCRR prohibit the use of centralized surface impoundments for HVHF flowback. This recommendation was made because it is best technology to eliminate the use of surface impoundments altogether, rather than gathering HVHF flowback into tanks at the drillsite and then moving it by pipeline or truck to be pumped into a larger open impoundment at a centralized location away from drillsites. If flowback is recycled, it should be trucked or piped from tank–to–tank to another drillsite or used at the same drillsite in a different well.

Eliminating use of centralized surface impoundments prevents: large scale surface disturbance that requires multi-year rehabilitation[190]; the potential for leakage to occur through or around the liner, impacting ground water; and the potential to generate substantial amounts of hazardous air pollution.

A centralized surface impoundment photograph in Pennsylvania is shown below.

Bednarski Centralized Waste Impoundment, Pennsylvania, Site Permit PADEP, 798407

The most serious concern with the use of centralized surface impoundments for HVHF flowback is the amount of hazardous air pollution predicted for these centralized surface impoundments. In 2009, NYSDEC estimated that each centralized impoundment would be a major source of hazardous air pollution, emitting more than 32.5 tons of air toxics per year, and it was unclear if NYSDEC's estimate was even a worst-case estimate:

[190] Surface disturbance is less for temporary tanks than impoundments. Impoundments require surface soil excavation and multi-year rehabilitation. Temporary tanks used at the drillsite use existing gravel space already in place for drilling operations rather that impacting new and additional surface terrain away from the drillsite.

> *Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission [estimate] of **32.5 tons** (i.e., "**major" quantity of HAP**) is theoretically possible at a central impoundment*[191] *[emphasis added].*

USEPA classifies a major source of hazardous air pollution as a source that emits more than 25 tons per year. These centralized impoundments have been sited nearby residential homes and community facilities in other states, increasing the amount of hazardous air pollution exposure to nearby humans, including increased exposure to benzene, a known human carcinogen.

In January 2011, NYS' consultant, Alpha Geoscience, complimented HCLLC for its recommendations on flowback impoundments, and supported improved mitigation:

> *Harvey Consulting has thoroughly documented their discussion of surface flowback impoundments and hazardous air pollutants, citing a professional journal article, technical guidance documents, consultant reports, and NYSDEC documents.* [192]

2011 RDSGEIS: The 2011 RDSGEIS states that centralized flowback impoundments are "not contemplated" by industry.[193]

> ***The Department was informed in September 2010 that operators would not routinely propose to store flowback water either in** reserve pits on the wellpad or in **centralized impoundments**. Therefore, these practices are not addressed in this revised draft SGEIS and such impoundments would not be approved without site-specific environmental review [emphasis added].*[194]

This industry representation is inconsistent with the actual practice of operators in Pennsylvania. Moreover, neither the RDSGEIS nor the proposed NYCRR amendments prohibit the use of centralized flowback impoundments. This leaves the door open for centralized flowback impoundments to be approved if a site-specific environmental review is conducted.

NYSDEC's requirement to use closed-loop HVHF flowback collection tanks at each drillsite is an efficient collection method, because fluid can be easily transferred to a treatment and disposal location, or taken to another well for reuse. It would not be efficient, or environmentally sound, to collect HVHF waste in a closed-loop flowback tank at the drillsite, and then transfer that waste by temporary piping or truck to a large centralized surface impoundment off of the drillsite location.

Recommendation No. 46: The SGEIS and NYCRR should prohibit the use of centralized surface impoundments for HVHF flowback based on the known impacts examined in the SGEIS process. HVHF flowback waste should be collected at the wellhead and recycled or directly routed to disposal. This prohibition should be described in the SGEIS as a mitigation measure and codified in the NYCRR.

[191] 2009, NYSDEC, DSGEIS, Page 6-56.

[192] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 31.

[193] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15.

[194] 2011 NYSDEC, RDSEGIS, Page 1-2.

If NYSDEC does not prohibit the use of centralized impoundments, the SGEIS should analyze the impacts and propose mitigation to protect public health and the environment. The decision to allow centralized flowback impoundments should not be segmented from the SGEIS just because it is known to create significant impacts. Prohibiting the use of centralized impoundments mitigates that known risk.

16. Repeat HVHF Treatment Life Cycle Impacts

Background: In 2009, HCLLC recommended that the DSGEIS disclose how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. HCLLC pointed out that the 2009 DSGEIS estimated water use and waste volumes based on a single initial fracture treatment and that this approach does not consider the fact that most shale gas wells require multiple fracture treatments.

2011 RDSGEIS: The 2011 RDSGEIS indicates there may be a potential for repeated HVHF treatments over the life of the well.[195] However, the 2011 RDSGEIS does not quantify the number of HVHF treatments possible per well, nor does it estimate the peak or cumulative impact of these HVHF treatments. Therefore the RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several decade long lifecycle.

NYSDEC does acknowledge that, when Marcellus repeat HVHF treatments are conducted, the impact will be equivalent to the initial treatment. However, its impact assessment does not examine the peak or cumulative impacts that may occur:

> *Regardless of how often it occurs, **if the high-volume hydraulic fracturing procedure is repeated it will entail the same type and duration of surface activity at the well pad as the initial procedure** [emphasis added].* [196]

For example, NYSDEC estimates 1,600 or more wells to be drilled and completed per year,[197] estimating a 30 year development life cycle,[198] for a total of 48,000 wells. NYSDEC estimates each HVHF treatment to use an average 4,200,000 gallons per well,[199] and that approximately 9-35% of HVHF treatment returns to the well and is produced as waste that requires handling, treatment and/or disposal. [200] A single HVHF treatment in each well, over a thirty year period, could yield a total waste load of 18-71 billion gallons. That waste volume could double or triple if two or three fracture treatments are conducted on each well over a several decade period. Assuming at least two fracture treatments, and possibly three may be implemented, the waste volumes would increase substantially, possibly exceeding 200 billion gallons.

NYSDEC acknowledges the fact that repeated HVHF treatments have been required in the Barnett shale, typically within 5 years from the initial HVHF.[201] However, NYSDEC notes:

> *Marcellus operators with whom the Department has discussed this question have stated their expectation that refracturing will be a rare event.*[202]

[195] 2011 NYSDEC, RDSGEIS, Page 6-275.
[196] 2011 NYSDEC, RDSGEIS, Page 5-99.
[197] 2011 NYSDEC, RDSGEIS, Page 2-1.
[198] 2011 NYSDEC, RDSGEIS, Page 6-6.
[199] 2011 NYSDEC, RDSGEIS, Page 6-10.
[200] 2011 NYSDEC, RDSGEIS, Page 5-99.
[201] 2011 NYSDEC, RDSGEIS, Page 5-98.
[202] 2011 NYSDEC, RDSGEIS, Page 5-98.

The information NYDEC gathered from a few Marcellus operators, that concludes Marcellus shale re-fracturing will be "rare", is inconsistent with industry literature.

For example, in 2010 Range Resource published a Society of Petroleum Engineering technical paper that describes two successful horizontal shale re-fracture re-stimulations and explains that Marcellus re-fracture stimulations will be used:

> *Based on the success of horizontal re-fracs in other shale plays, re-fracture stimulations in the Marcellus will be an excellent option to maximize fracture complexity and increase the total effective fracture network. …These re-fracs can be utilized to soften overall field decline in future years…"*[203]

In 2006, Schlumberger, an Oil & Gas Service Company, published a Society of Petroleum Engineering technical paper describing the benefits of re-fracture re-stimulations to increase hydrocarbon production in wells that were initially fractured and where hydrocarbon production had declined to a point that it was economically attractive to repeat the fracture stimulation procedure in that same well:

> *A successful refracturing treatment is one that creates a fracture having higher fracture conductivity and/or penetrating an area of higher pore pressure than the previous fracture.*[204]

Schlumberger explains that re-fracture re-stimulations are likely in wells that have the following characteristics: low productivity relative to other wells with comparable pay; remaining reserves in place; need for fracture reorientation to improve hydrocarbon production; poorly placed initial fracture treatment (e.g. proppant crushing, or proppant flowback, use of incompatible fluids); and reservoir complexity leading to poor hydrocarbon recovery.

A 2010 Apache Corporation, Society of Petroleum Engineering paper, agrees that re-fracture re-stimulations will play an important role in shale stimulation for some time to come. Apache Corporation explains that re-fracture re-stimulations are being used in shale wells to increase gas production, and to make good wells even better gas producers:

> *Refracs of even good wells increased the recovery and re-established near initial production rate. Increasing stimulated reservoir volume should increase both the IP*[205] *and EUR*[206]*. When new areas of the shale are exposed in a refrac, there should also be a gain in reserves (Warpinski, 2008). Increases in stimulated reservoir volume could be accomplished by opening many of the micro-cracks and laminations within the undisturbed matrix blocks in the initial drainage [area] that were left unstimulated by previous fracturing attempts. Re-opening of natural and hydraulic fractures that had closed due to overburden and confining stress created by depletion would re-establish matrix area contact.*[207]

[203] Curry, M., and Maloney, T., Range Resources Corp., Woodroof, R., and Leonard, R. ProTechnics Division of Core Laboratories, Less Sand May Not Be Enough, Society of Petroleum Engineers Technical Paper, SPE 131783, 2010. Page 12.

[204] Moore, L.P., Ramakrishnan, H,, Schlumberger, Restimulation: Candidate Selection Methodologies and Treatment Optimization, Society of Petroleum Engineers Technical Paper, SPE 102681, 2006. Page 1.

[205] IP= Initial Production.

[206] EUR= Expected Ultimate Recovery.

[207] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

Re-fracture re-stimulation has been used widely in the Barnett Shale. Many technical papers report successful re-fracture re-stimulations in the Barnett Shale where improved HVHF slickwater fractures were used as a second treatment after the initial cross-linked gel fracture treatment. While the Marcellus and Utica Shales in NYS will start with improved HVHF slickwater fracture treatments, these treatment methods will continue to improve over time, and like the Barnett, repeat fracture treatments will be required to improve hydrocarbon performance as new and improved fracture treatment design supplants existing technology. Apache Corporation explains:

> *Fracturing technology for shales is constantly improving and refracs may slowly fade from common use as the frac designs for shale wells are optimized.* ***Until optimal fracs are achieved and production engineering is optimized, however, refracs will have a place in shale stimulation*** *[emphasis added].*[208]

Additionally, NYSDEC acknowledges the benefits of re-fracture treatment:

> *Several other reasons may develop to repeat the fracturing procedure at a given well. Fracture conductivity may decline due to proppant embedment into the fracture walls, proppant crushing, closure of fractures under increased effective stress as the pore pressure declines, clogging from fines migration, and capillary entrapment of liquid at the fracture and formation boundary. Refracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.* [209]

Recommendation No. 47: The SGEIS should quantify how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. Additionally, the SGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts.

[208] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

[209] 2011 NYSDEC, RDSGEIS, Page 5-98.

17. Air Pollution Control and Monitoring

Air Quality Impact Assessment Modeling Analysis:

In 2009, AKRF's comments on the 2009 DSGEIS (prepared for NRDC) identified a number of shortcomings in the air quality impact assessment modeling analysis. Notably, that emissions from 10 wells per year and simultaneously operating equipment would produce emission impacts that exceed the NAAQS.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantial amount of new modeling work and a number of operational restrictions and limitations to ensure that NAAQS are not violated. While the RDSGEIS has been significantly improved in this area, some problems with the analysis persist, and some new problems have developed.

The following assumptions used in the air quality impact assessment modeling analysis warrant further review and justification:

- The modeling analysis assumes that a maximum of four wells per drillsite will be drilled each year.[210] However, NYS ECL § 23-0501 requires development of all infill drilling within three years of the first well drilled, and the RDSGEIS envisions the Marcellus Shale gas reservoir will be developed from a multi-well pad for a 640-acre spacing unit, with 40-acre spacing. At 40-acre spacing density, 16 wells would need to be drilled in three years to fill a 640-acre unit, meaning that a maximum of 5-6 wells could possibly be drilled per year. This conflicts with the 4 wells per year (12 wells for three years) assumption and would generate more significant air quality impacts than contemplated by the RDSGEIS.
- Gas compositional data used in the modeling analysis was based on Marcellus Shale gas only. There was no analysis of Utica Shale gas or gas from any other low-permeability gas reservoir.[211] Modeling should be based on a reasonable worst case scenario that includes analysis of all shale formations with development potential, not just the Marcellus Shale, if the SGEIS proposes to cover more reservoirs.
- The modeling analysis assumed that there will be no emissions of criteria pollutants from venting. However, the RDSGEIS proposes to allow gas venting of up to 5 MMscf during any consecutive 12-month period, including sour gas, as long as it is vented at least 30 feet in the air. This allowance undermines the assumption that no criteria pollutants would be emitted during venting.
- The modeling analysis assumes only three days of gas flaring per well. However, the RDSGEIS states that flaring can occur for up to a month in some cases.[212] Therefore, the modeling understates the potential emissions from flaring.

[210] 2011 NYSDEC, RDSGEIS, Page 6-104.

[211] 2011 NYSDEC, RDSGEIS, Page 6-115.

[212] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

- The supplemental 24-hour $PM_{2.5}$ model impacts analysis did not evaluate simultaneous operation of equipment operating on the pad. However, other short-term impact assessment assumed simultaneous operation of one well drilling, one well completion and one well flaring, along with operation of the on-site line heater and off-site compressor for the gas production phase for previously-completed wells.[213] Therefore, the 24-hour $PM_{2.5}$ impact modeling is based on inconsistent assumptions.

- To account for the possibility of simultaneous well operations at nearby pads, a simplified sensitivity analysis was performed in the RDSGEIS to determine the potential contribution of an adjacent pad to the modeled impacts.[214] This modeling assumed a single adjacent pad, located one kilometer away (0.62 miles), with identical equipment and emissions as the modeling target pad.

  The RDSGEIS model only examined the potential for two multi-well drillsites, drilling horizontal wells to be located near each other at a distance of 0.62 miles apart. The modeling analysis assumed that only two drillsites would be operating nearby each other, and that drillsite development in an area would occur in a sequential fashion,[215] which is not always the case (especially when there are multiple operators developing an area).

  The modeling analysis did not evaluate the possibility of more than two multi-well drillsite drilling and completion operations adjacent to each other, nor did it evaluate the possibility of multi-well drillsites operating nearby several single well drilling and completion operations drilled on 40 acre spacing. Nor did the analysis examine the possibility that the surface location of multi-well drillsites could be positioned closer than 0.62 miles apart.

  NYS does not require drillsites to be located over the drilling unit, as long as surface siting approval is authorized. Therefore there is a possibility for drillsites to be located closer than 0.62 miles, a possibility of simultaneous operation of more than two drillsites at a time, and a possibility that more significant overlapping ambient air pollution impacts may occur than modeled. Therefore, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. NYSDEC wither needs to examine all possible concurrent operation impacts, or prohibit the possibility.

- Mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal).

  The RDSGEIS assumes that both light and heavy duty trucks will only travel 20-25 miles[216] one way, yet out-of-state treatment and disposal facilities may be located several hundred miles away. For rural operations, it is unlikely that supplies, equipment, specialty contractors, lodging, and other support equipment and personnel will be located within 20-25 miles of the drillsite.

[213] 2011 NYSDEC, RDSGEIS, Page 6-124.

[214] 2011 NYSDEC, RDSGEIS, Page 6-127.

[215] 2011 NYSDEC, RDSGEIS, Page 6-136.

[216] 2011 NYSDEC, RDSGEIS, Page 6-176.

- The modeling analysis assumes that there will be no simultaneous operations of well drilling and completion equipment on a drillsite. There is a permit requirement prohibiting simultaneous operations;[217] however, this requirement is not codified in the proposed revisions to NYCRR.[218]

Recommendation No. 48: The RDSGEIS air quality impact assessment modeling analysis assumptions warrant additional review and justification. Limitations used in the modeling assumption must all be translated into SGEIS as mitigation measures and codified in the NYCRR to ensure the assumed impacts will not be exceeded. This was done in some cases, but not all. In the cases where modeling assumptions used cannot be justified, modeling revisions will be needed to examine impacts and identify required mitigation, or operational limits set.

Air Quality Monitoring Program:

In 2009, AKRF recommended improved air dispersion modeling and a region-wide emissions analysis. In response, NYSDEC completed a significant amount of additional work on the air quality section of the RDSGEIS. A major conclusion from this work was that there is insufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$. As a result of this lack of data, these impacts were not fully quantified by modeling alone. Furthermore, NYSDEC concluded that ambient air quality monitoring program is needed.

While implementation of a ambient air quality monitoring program, is an important improvement in the RDSGEIS, the proposed program needs further definition, a funding commitment, and a formal industry compliance obligation.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a commitment to implement local and regional air quality monitoring:[219]

> ***The Department also developed an air monitoring program to fully address potential for adverse air quality impacts beyond those analyzed in the dSGEIS, which are either not fully known at this time or not verifiable by the assessments to date.*** *The air monitoring plan would help determine and distinguish both the background and drilling related concentrations of pertinent pollutants in the ambient air [emphasis added].*[220]
>
> *The dSGEIS identifies additional mitigation measures designed to ensure that emissions associated with high-volume hydraulic fracturing operations do not result in the exceedance of any NAAQS. In addition,* ***the Department has committed to implement local and regional level air quality monitoring at well pads and surrounding areas*** *[emphasis added].*[221]

[217] 2011 NYSDEC, RDSGEIS, Appendix 10, Attachment A, Condition 2.

[218] 2011 NYSDEC, RDSGEIS, Page 6-115.

[219] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.

[220] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 16.

[221] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.

Although Section 6.5.4 of the RDSGEIS proposes alternative methods for implementing air quality monitoring, it does not settle on a recommended solution.[222] The RDSGEIS proposes two alternatives: (1) industry-led monitoring with NYSDEC oversight, or (2) NYSDEC monitoring with industry funding. The RDSGEIS identifies NYSDEC monitoring with industry funding as the preferred alternative without making clear how this goal will actually be funded and implemented.

Table 6.24 proposes to: add a single air monitoring trailer and mobile laboratory to monitor ozone, particulate matter, oxides of nitrogen and air toxics; use infrared cameras to monitor gas leaks; and conduct summa canister sampling for BTEX and other VOCs. However, the RDSGEIS does not explain how the addition of a single mobile trailer and lab along with some other intermittent sampling will provide sufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$.

The RDSGEIS did not evaluate the possibility of installing permanent monitoring locations at numerous locations in NYS, with priority in existing non-attainment areas, and areas that will be heavily impacted by shale gas development. Instead, the RDSGEIS only proposes to examine "regional level" monitoring by collecting data at two sites in NYS.[223] This proposal is insufficient because monitoring regional ambient air quality is not possible with the limited data provided by a two-site program, proposed for an unspecified time period.

More information is needed to understand the scope and duration of NYSDEC's proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling.

The obligation to fund the air quality monitoring program needs to be clearly tied to a permit condition requirement—for example, the permit to flare or spud a well should require a contribution to an air quality monitoring fund; such a requirement is not set forth in either Appendix 6 or Appendix 10.

Recommendation No. 49: The SGEIS should include a more rigorous air monitoring program to achieve NYSDEC's goal of regional and local air pollutant impact monitoring. The proposed program should identify: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

The RDSGEIS acknowledges that air monitoring may identify peak or cumulative air pollution impacts that warrant additional emission controls. For example, NYSDEC has identified that:

> *…the consequences of the increased regional NOx and VOC emissions on the resultant levels of ozone and PM2.5 cannot be fully addressed by only modeling at this stage due to the lack of detail on the distribution of the wells and compressor stations. In addition, any potential emissions of certain VOCs at the well sites due to fugitive emissions,*

[222] 2011 NYSDEC, RDSGEIS, Page 6-180 through 6-184.

[223] 2011 NYSDEC, RDSGEIS, Page 6-181.

> *including possible endogenous level, and from the drilling and gas processing equipment at the compressor station (e.g. glycol dehydrators) are not fully quantifiable.*[224]

However, the RDSGEIS does not explain NYSDEC's plan to collect data, identify the potential for air pollutants to exceed the federal, state or local air pollution control standards, or require these additional emission controls in a timely manner before adverse impacts are realized by humans or the surrounding ecosystem.

Recommendation No. 50: The SGEIS should explain NYSDEC's plan to collect data, identify the potential for pollution problems to exceed the federal, state or local air pollution control standards, and the timely installation of additional emission controls, in order to protect against exceedances of pollution control standards, should be required as an SGEIS mitigation measure and codified in the NYCRR.

GHG Impacts Mitigation Plan:

In 2009, HCLLC and AKRF recommended further analysis of Greenhouse Gas (GHG) impacts and mitigation. In response, NYSDEC acknowledged the potential for GHG emissions impacts and the need for mitigation. While such acknowledgement represents a substantial improvement from the 2009 draft, the proposed mitigation needs improvement to ensure the requirements are clear, measureable and enforceable.

The 2011 RDSGEIS: The 2011 RDSGEIS requires a GHG Impacts Mitigation Plan.[225]

> *The Plan must include: a list of best management practices for GHG emission sources for implementation at the permitted well site; a leak detection and repair program; use of EPA's Natural Gas Star best management practices for any pertinent equipment; use of reduced emission completions that provide for the recovery of methane instead of flaring whenever a gas sales line and interconnecting gathering line are available; and a statement that the operator would provide the Department with a copy of the report filed with EPA to meet the GHG Reporting Rule.*[226]

The GHG Impacts Mitigation Plan requires the operator to implement a Leak Detection and Repair Program,[227] use Reduced Emission Completions,[228] use EPA Natural Gas STAR program recommendations, and identify other best management practices.

The requirement that a GHG Impacts Mitigation Plan be prepared and include the use of best management practices for GHG control is a step in the right direction; however, given the variety of best management practices under EPA's voluntary Natural Gas STAR program, NYSDEC should require that well operators select and install the controls that will achieve the greatest emissions reductions possible. In addition, such emissions reductions should be made enforceable, as permit conditions or in the NYCRR.

[224] 2011 NYSDEC, RDSGEIS, Page 6-181.

[225] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[226] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[227] See also HCLLC recommendations on LDAR Program in this section of the report.

[228] See also HCLLC recommendations on Reduced Emission Completions in this section of the report.

For example, the Natural Gas STAR Program data shows that it is both technically feasible and economically attractive to use "low-bleed" or "no-bleed pneumatic controllers and plunger lift systems;[229] however, it is not clear whether an operator would be required under the GHG Impacts Mitigation Plan to use this technology, or how NYSDEC would enforce its use if an operator chose not to select it.

NYSDEC should require operators to use Natural Gas STAR Program best management technologies and practices that will optimize emissions reductions.

The RDSGEIS does not make clear whether or how new technologies or practices would be required (e.g. technologies or practices identified by the Natural Gas STAR Program after drillsite construction has been completed). It is not clear if an operator will be required to implement GHG emission controls only at the time of construction, or if there will be an ongoing obligation to implement additional controls as they are identified by the Natural Gas STAR Program and developed.

The plan should include a list of emission controls that will be installed at the time of construction and best management practices, and a process for periodically reviewing new technologies and installing them as new control solutions are developed over time.

Recommendation No. 51: NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions.

The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs.

The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Flare and Venting of Gas Emissions:

In 2009, HCLLC recommended that flaring and venting be limited to the lowest level technically feasible and safe. Reducing gas flaring and venting is widely considered best practice. Both federal and state governments have taken steps over the past two decades to enact regulations that limit flaring and venting of natural gas.[230] Initially the motive was to conserve hydrocarbon resources to maximize federal and

[229] Older gas wells stop flowing when liquids (water and condensate) accumulate inside the wellbore creating backpressure on the hydrocarbon formation. This will be a future problem in NYS, as gas wells age. Methane gas is emitted when companies open wells to vent gas to the atmosphere to unload wellbore liquids (water and condensate that accumulate in the bottom of the well) in order to resume gas flow. The industry typically refers to this process as "blowing down the well" or a "well blowdown." Eventually, even a well's own gas pressure becomes insufficient to flow accumulated liquids to the surface and the well is either shut-in as uneconomic, or some form of artificial lift (e.g. plunger lifts) is installed to transport the liquids to the surface.

[230] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.

state revenue and gas supply. More recently, focus on GHG, VOC and HAPs emission reduction has prompted additional innovation to further reduce flaring and venting.

Flares may be used during well drilling, completion, and testing to combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. If gas processing equipment and pipeline systems are in place, gas flaring can be avoided in all cases except in the event of equipment malfunction. During the drilling and completion phase of the first well on a well pad, a gas pipeline might not be installed. Gas pipelines are typically not installed until it is confirmed that an economic gas supply has been found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline to which it can be routed. The RDSGEIS proposes to require Reduced Emission Completions for all wells where a pipeline is installed, which will reduce the need to flare or vent gas.

During production operations, high pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. At natural gas facilities, continuous flaring or venting may be associated with the disposal of waste streams[231] and gaseous by-product streams[232] that are uneconomical to conserve. Venting or flaring may also occur during manual or instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and pipeline repair.[233]

Best practices for planned[234] flaring and venting during gas production should limit flaring and venting to the smallest amount possible and only for purposes of for safety. Gas should be collected for sale, and used as fuel unless it is proven to be technically and economically unfeasible.

The 2011 RDSGEIS: The 2011 RDSGEIS limits planned gas flaring to flowback operations for wells where a gas sales line has not been installed which is a significant improvement.[235]

However, when flaring or venting does occur, there is the potential for relatively high short-term VOC and CO emission impacts that need to be considered.[236] The RDSGEIS states that industry only plans to flare for a maximum of three days, and NYSDEC only modeled a 3-day impact; yet, the RDSGEIS states that flaring can occur for up to a month (30 days) in some cases. [237]

> ***A flaring period of 3 days was considered for this analysis*** *for the vertical and horizontal wells respectively although* ***the actual period could be*** *either shorter or* ***longer*** *[emphasis added].*[238]

Modeling needs to represent a reasonable worst case scenario. Because only a three day flaring period was considered in the RDSGEIS modeling, planned flaring should be limited to no more than three days.

[231] For example, acid gas from the gas sweetening process and still-column overheads from glycol dehydrators.

[232] For example: instrument vent gas; stabilizer overheads and process flash gas.

[233] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[234] There is a difference between planned flaring and emergency flaring. Emergency flaring is conducted to safely route combustible and potentially toxic (e.g. hydrogen sulfide gas) and in most cases cannot be avoided. Planned flaring can be avoided in most cases.

[235] 2011 NYSDEC, RDSGEIS, Page 5-135.

[236] 2011 NYSDEC, RDSGEIS, Page 6-103.

[237] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

[238] 2011 NYSDEC, RDSGEIS, Page 6-197.

Alternatively, modeling analysis should be based on the maximum time period that flaring would be allowed.

Recommendation No. 52: Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. Flaring restrictions should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC should require operators to flare gas as a preferred method over venting. Gas flaring is environmentally preferable over venting because flaring reduces HAP, VOC, and GHG emissions.[239] Proposed revisions to 6 NYCRR § 560.6(c)(28) would require that gas be flared whenever technically feasible instead of vented,[240] which is a significant improvement.

The RDSGEIS limits the amount of flaring and venting that is allowed at a drillsite during any consecutive 12-month period; however, it is unclear how the venting (5 MMscf) or flaring (120 MMscf) thresholds were developed, and such thresholds are not listed in the proposed revisions to the NYCRR.

- *During the flowback phase, the **venting of gas** from each well pad will be limited to a maximum of **5 MMscf** during any consecutive 12-month period. If "sour" gas is encountered with detected hydrogen sulfide emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m);*
- *During the flowback phase, **flaring of gas** at each well pad will be limited to a maximum of **120 MMscf** during any consecutive 12-month period [emphasis added].*[241]

Recommendation No. 53: The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting limits, once justified, should be included in the SGEIS as a mitigation measure, codified in the NYCRR, and should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC require that well operators follow best practices for construction and operation of flares used for safety. The RDSGEIS requires self-igniting flares,[242] which is an improvement; however, the RDSGEIS does not require that:

- Flare pilot blowout risk be minimized by installing a reliable flare system;
- Low/intermittent velocity flare streams have sufficient exit velocity or wind guards;
- A reliable ignition system is used;

[239] Fugitive and Vented methane has 21 times the global warming potential as combusted methane gas. Methanetomarkets.org, epa.gov/gasstar.

[240] 2011 NYSDEC, RDSGEIS, Page 7-117.

[241] 2011 NYSDEC, RDSGEIS, Page 7-108.

[242] 2011 NYSDEC, RDSGEIS, Page 7-117.

- Liquid carry over and entrainment in the gas flare stream is minimized by ensuring a suitable liquid separation system is in place; or
- Combustion efficiency is maximized by proper control and optimization of flare fuel/air/steam flow rates.

Recommendation No. 54: The SGEIS should require flare systems to be designed in a manner that optimizes reliability, safety, and combustion efficiency, including requirements to: minimize the risk of flare pilot blowout by installing a reliable flare system; ensure sufficient exit velocity or provide wind guards for low/intermittent velocity flare streams; ensure use of a reliable ignition system; minimize liquid carry over and entrainment in the gas flare stream by ensuring a suitable liquid separation system is in place; and maximize combustion efficiency by proper control and optimization of flare fuel/air/steam flow rates. Flare design requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

Reduced Emission Completions:

In 2009, HCLLC recommended the use of Reduced Emission Completions (RECs, also known as "green completions") to control methane and other greenhouse gas (GHG) emissions following HVHF operations. RECs also reduce nitrogen oxide (NO_x) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere.

EPA estimates that, on average, an REC can capture 7,700 Mcf/well workover for an unconventional gas well. If, for example, 2,000 wells are exempted during the first few years of Marcellus Shale gas development in NYS before pipeline infrastructure is more broadly developed, that could result in 15.3 Bcf (6.2 $MMTCO_2e$) of methane gas vented to the atmosphere.

To put the significance of 15.3 Bcf of methane gas (6.2 $MMTCO_2e$) into perspective, it is equivalent to the GHG emissions from:

- Over 1,100,000 passenger vehicles; or
- The electric use of approximately 700,000 homes for one year; or
- 13,000,000 barrels of oil consumed.[243]

The 2011 RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of well-sites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale.

Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued.

[243] EPA Greenhouse Gas Equivalencies Calculator, http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results

> *Reduced Emissions Completion (REC) would be required whenever a gathering line is already constructed. In addition,* ***two years after issuance of the first permit for high volume hydraulic fracturing, the Department would evaluate whether the number of wells that can be drilled on a pad without REC should be limited*** *[emphasis added].*[244]

NYSDEC should not defer the implementation of this known best practice, because it could result in the exemption of several thousand wells from this control technology requirement, leading to unmitigated air quality impacts from uncontrolled venting. HCLLC agrees that RECs are not an option for single exploration wells with no offset wells or pipeline infrastructure nearby. In addition, RECs may not be possible if well pressure is too low. Regulations should make exceptions only for these situations in which emission control is truly infeasible. However, RECs should be required in all other circumstances.

Once an exploration well is drilled and hydrocarbons are located, additional drilling and well completion operations on that same drillsite should be coordinated with gas line installation, enabling RECs for all subsequent wells. High-volume hydraulic fracturing can be completed at any time after a well is drilled and gas is found. The well can be temporarily suspended, and the HVHF be conducted once a gas line is in place. In a newly explored area, it may be reasonable to drill an exploration well, and conduct a HVHF treatment to test gas productivity before drilling additional production wells. However, once a commercial source of gas is identified and tested with that initial exploration well, there is no reason to vent or flare gas using the HVHF flowback process and test wells prior to a gas line installation.

In natural gas fields, gas from the first well is often flared or vented during drilling and completion activities, because natural gas pipelines are typically not installed until it is confirmed that an economical gas supply has been found. However, once a pipeline is installed, subsequent wells drilled on that same pad would be in a position to implement REC techniques.

Operators often point to the lack of pipeline infrastructure as a primary reason REC may not be possible. However, there are also alternatives to piping methane, such as using it onsite to generate power, re-injecting it to improve well performance, or providing it to local residents as an affordable power supply. Therefore, RECs do not need to rely solely on the installation of a nearby pipeline.

RECs are technically feasible and economically attractive, and are a commercially available emission control option. Appendix 25 of the RDSGEIS, Reduced Emission Completions Executive Summary, summarizes the economic benefits, making a clear case for requiring this technology on all NYS wells, with few exceptions. RECs provide an immediate revenue stream by routing gas (methane and gas condensates) to a gas sales line that would otherwise be vented into the atmosphere or flared.. Alternatively, captured gas can be used for fuel, offsetting operating costs, or re-injected to improve well performance. Industry has demonstrated that RECs are both an environmental best practice and profitable.

In addition to being economically attractive for the operator, there are a number of other benefits of RECs:

- The collection of potentially explosive gas vapors, rather than venting them to the atmosphere. This improves well site safety, reduces worker exposure to harmful vapors, and limits overall corporate liability.
- The reduction in emissions, noises, odors, and citizen complaints associated with venting or flaring.
- The reduction in disposal costs, as a result of gas and condensate capture and sale.

[244] 2011 NYSDEC, RDSGEIS, Page 1-116.

- The elimination of the need to secure flare permits and provide flaring notifications.[245]
- The reduction of VOCs and HAPs. Unprocessed natural gas contains VOCs and HAPs, along with methane. Flaring, an alternative control device, can reduce VOCs and HAPs. However, flaring generates NO_X and particulate matter (PM), as well as other combustible byproducts. Many areas with significant oil and gas development have challenges achieving ozone and regional haze standards. Therefore, REC technology is a preferred alternative.
- Wells flow back to portable separation units for longer periods than would be allowed with direct venting into the atmosphere or flaring, providing improved well cleanup and enhanced well productivity.
- Fewer wells are drilled as more methane is kept in the system and sent to market, thereby reducing a range of environmental impacts.

While some operators report the voluntary use of RECs, many wells in the United States are still drilled without REC. And, even for companies that have announced the use of RECs, it is not clear how extensively RECs are implemented. Thus, many states have put REC requirements into effect.

The commercial availability of REC equipment has become so widespread that it is now required in several states. For instance, Colorado requires RECs on all oil and gas wells unless they are not technically and economically feasible.[246] Fort Worth, Texas requires RECs.[247] Wyoming has required RECs in the Jonah-Pinedale Anticline Development Area (JPAD) since 2007, and more recently, Wyoming has expanded this requirement to all Concentrated Development Areas (CDAs) of oil and gas in the state.[248]

In 2005, EPA estimated that an average of 7,000 Mcf of natural gas can be recovered during each REC.[249] In 2011, EPA increased the emission recovery estimate and created two distinct categories of wells that are major contributors to methane emissions: Unconventional Gas Wells (7,700 Mcf/well workover) and Low Pressure Gas Well Cleanup (1,400 Mcf/well/year). For each unconventional gas well completion, there is an opportunity to generate about $31,000 in gross revenue, creating a very short payout period if the operator invests in its own equipment.[250]

Investment in REC equipment is extremely profitable, with a conservative average investment cost of $10,000 per REC.[251] The payout occurs quickly if a contractor is hired and the operator only pays a per well REC equipment rental charge. As long as the gas that is captured and sold exceeds the equipment rental charge, the payout is immediate.

Oil and gas operators that have a sufficient number of wells to amortize the cost of REC equipment are finding it more economically attractive to invest in their own technology. Most of the companies that have gone this route report a one- to two-year payout, and substantial profitability thereafter, depending on the gas and condensate recovery rate.[252] For smaller operators, it is possible, and maybe more

[245] Flaring is not always practicable near populated areas or areas of high forest fire risk.

[246] Colorado Oil and Gas Conservation Commission, Rule § 805(b)(3)

[247] Fort Worth Texas, Ordinance No. 18449-02-2009.

[248] Wyoming Oil and Gas Production Facilities, Chapter 6, Section 2, Permitting Guidance, March 2010.

[249] United States Environmental Protection Agency, Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.

[250] (7,700 Mcf)($4/Mcf)= $30,800

[251] EPA's Green Completion PRO FACT Sheet No.703 estimates the cost between $1K and $10K; a $10K per completion cost estimate is conservative.

[252] EPA Natural Gas STAR, Green Completions, PRO Fact Sheet No. 703, September 2004.

financially feasible, to rent REC equipment from a contractor. The profitability math is simple. In 2005, the EPA estimated that, on average, 7,000 Mcf/well of natural gas could be captured, yielding a profit of $14K per well, with a payback of less than one year.[253] However, it is important to note that EPA's 2005 profitability calculations were based on lower gas prices ($3/Mcf) than the current market rate ($4+/Mcf). Using the EPA's new 2011 estimate of 7,700 Mcf/well and a gas price of $4/Mcf, each well, on average, has the potential to generate $31,000 in gross revenue. A portion of that revenue stream must be allocated to purchasing or renting the required REC equipment, but unless that cost is greater than $31,000 per well, a REC is a profitable endeavor. Profitability will vary based on the market price for gas and the cost of carrying out the REC.

The EPA has found that RECs are a major contributor to methane reductions on a national scale. In 2008, 50 percent of the EPA's Natural Gas STAR Program's annual total reductions for the oil and gas production sector was attributed to REC s.[254] Therefore, requiring this technology will be very important to NYS' and EPA's GHG emission reduction goals.

Recommendation No. 55: Drilling and well completion operations should be coordinated with gas line installation, enabling RECs for all wells drilled subsequent to the initial exploration well. Alternatively, methane gas should be used onsite to generate power, re-injected to improve well performance, or provided to local residents as an affordable fuel supply. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Wastewater Impoundments:

In 2009, HCLLC pointed out that centralized wastewater impoundments have the potential to be a major source of HAPs—EPA lists facilities that release 10 tons of a single HAP per year as major sources. The 2009 DSGEIS estimated 32.5 tons of methanol[255] per year—more than three times the HAP major source threshold—could be emitted from centralized wastewater impoundments.[256] This large amount of hazardous air pollution was identified as an unmitigated significant impact.

In 2009, HCLLC recommended the use of closed loop collection and tank systems, rather than wastewater impoundments, as a best practice. The 2011 RDSGEIS prohibits the use of wastewater impoundments at the drillsite, requiring closed loop collection and tank systems. This is a substantial improvement. However, the RDSGEIS does not prohibit centralized flowback impoundments at locations

[253] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[254] 2009 EPA Natural Gas STAR Program Accomplishments, available online at http://www.epa.gov/gasstar/documents/ngstar_accomplishments_2009.pdf. Total sector reductions (2008) = 89.3 Bcf of which 50 percent are the result of RECs (50% of 89.3 Bcf = 45 Bcf).

[255] EPA lists methanol as a hazardous air pollutant, but has not yet classified it with respect to carcinogenicity. The reproductive and developmental effect of methanol on humans is not yet understood. http://www.epa.gov/ttn/atw/hlthef/methanol.html. Testing in rats has yielded skeletal, cardiovascular, urinary system, and central nervous system malformations. American Conference of Governmental Industrial Hygienists (ACGIH), TLVs and BEIs, Threshold Limit Values for Chemical Substances and Physical Agents, Biological Exposure Indices, Cincinnati, OH, 1999. In humans, chronic inhalation or oral exposure may result in headaches, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, blurred vision, and blindness. Neurological damage, specifically permanent motor dysfunction, may also be a result. The Merck Index. An Encyclopedia of Chemicals, Drugs, and Biologicals. 11th ed. Ed. S. Budavari. Merck and Co. Inc., Rahway, NJ. 1989.

[256] 2009 NYSDEC, DSGEIS, Page 6-57.

away from the drillsite and fails to analyze the impacts of such centralization. This represents impermissible segmentation. It is recommended that centralized flowback impoundments be prohibited, however, if this recommendation is not adopted a new draft should be prepared analyzing the potential impacts posed by the reliance on centralized impoundments to store and treat HVHF wastewater and made available for public comment; such a significant analysis cannot be deferred until future site-specific review.

Despite the RDSGEIS's reliance on representations by industry that centralized flowback impoundments are not contemplated at this time, recent experience in Pennsylvania, and other states, reveals that industry's use of centralized flowback impoundments has become common practice. The RDSGEIS either needs to clearly prohibit the use of centralized flowback impoundments in NYS or analyze the potential environmental impacts, including human health impacts, posed by such use and develop ways to avoid or mitigate such impacts.

While industry may not presently intend to build centralized flowback impoundments in NYS, that could change in the future. Based on the use of centralized flowback impoundments as a common industry practice, this is a reasonably foreseeable impact, and unless prohibited is an unmitigated significant impact.

As proposed, there would be no limitations in place for these types of impoundments:

> ***Since September 2009 industry has provided information that****: (1) simultaneous drilling and completion operations at a single pad would not occur; (2) the maximum number of wells to be drilled at a pad in a year would be four in a 12-month period; and* ***(3) centralized flowback impoundments, which are large volume, lined ponds that function as fluid collection points for multiple wells, are not contemplated*** *[emphasis added].*[257]

Recommendation No. 56: The use of centralized impoundments to collect waste should be prohibited because these impoundments are a major source of air pollution. This prohibition should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

If centralized flowback impoundments are not prohibited, the potential adverse impacts to human health and the environment must be analyzed fully by NYSDEC. Given that the RDSGEIS includes no analysis whatsoever of the impacts of centralized flowback impoundments, a new draft must be prepared and made available for public comment in order to satisfy the requirements of SEQRA; deferring such analysis for later review would constitute impermissible segmentation. Moreover, mitigation measures to address the potential significant impacts must be included in the SGEIS and codified in the NYCRR.

Gas Dehydrators:

In 2009, HCLLC pointed out that gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions.

[257] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15-16, and Page 6-111.

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. These gases are vented to atmosphere unless pollution controls are installed. Best technology for dehydration units includes the installation of flash-tank separators to recover gas pollutants. Alternatively, pollutants can be routed to a vapor collection/destruction unit, or desiccant dehydrators can be used. Desiccant dehydrators have shown to cost less than flash-tank separators, have lower operating and maintenance costs, and control 99% of HAPs.[258]

The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement.

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, requires:

> *The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control device to limit the benzene emissions to one ton/year;* [259]

The 2011 RDSGEIS also requires a GHG impacts mitigation plan[260] that includes an evaluation of EPA Natural Gas STAR Best Practices for methane and other GHG emissions. However, it does not make GHG emission controls for gas dehydrators mandatory.

NYSDEC's requirement to control emissions from all dehydrators emitting more than one ton per year of benzene will result in emission control on a number of NYS dehydration units. However, smaller dehydration units that do not fall under this requirement may still have economical methane emission control opportunities.

In 2011, the EPA estimated that approximately 8 Bcf of methane is emitted from gas dehydration systems annually. Most of this methane is emitted from smaller glycol dehydration units currently fall below federal regulatory thresholds for emission control. That methane could instead be captured for sale or use as fuel.[261] While the EPA requires a number of large glycol dehydrators to install emission controls, under the federal Maximum Achievable Control Technology (MACT) standards at 40 CFR Part 63, Subpart HH, small glycol dehydrators are typically exempt. Many small operating glycol dehydrator units do not have flash tank separators, condensers, electric pumps, or vapor recovery installed.

There are four straightforward solutions readily available to control methane emissions from TEG dehydrator units, including: installing a flash tank separator; optimizing the glycol circulation rate; rerouting the skimmer gas; and installing an electric pump to replace the natural gas driven energy exchange pump.

A typical glycol dehydration system includes the following components:

- **Glycol Contactor**: Wet gas enters the glycol contactor. Glycol removes moisture from the gas by the process of physical absorption. Along with removing moisture, the glycol also absorbs methane,

[258] Fernandez, R., Petrusak, R., Robinson, D., Zavadil, D., Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.

[259] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109, and Appendix 10, Attachment A.

[260] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[261] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

VOCs, and HAPs. Dry gas exits the glycol contactor absorption column and is either routed to a pipeline or a gas plant.

The glycol contactor unit plays the primary role in dehydrating gas to pipeline specifications; the rest of the glycol dehydration system is required to convert the now moisture rich glycol back into a lean product that can be re-used to dehydrate more incoming gas. Therefore, the next step in the process is to route the moisture rich glycol to "regenerator" and "reboiler" units.

- **Glycol Regenerator & Reboiler:** Glycol loaded with moisture, methane, VOCs, and HAPs ("rich glycol") exits the bottom of the glycol contactor unit and is routed to the glycol regenerator and reboiler units, where the absorbed components are removed and "lean" glycol is created. If emission controls are not installed, methane, VOCs, HAPs, and water are boiled off and vented to atmosphere from the regenerator and reboiler units.

  One way to limit the amount of methane, VOCs, and HAPs emitted to the atmosphere from the regenerator and reboiler units is to install a flash tank separator.

- **Flash Tank Separator:** The installation of a flash tank separator between the glycol contactor and the glycol regenerator/reboiler units creates a pressure drop in the system, allowing methane and some VOCs and HAPs to flash out of (separate from) the glycol. The amount of pressure drop that can be created is a function of the fuel gas system pressure or compressor suction pressure, because methane gas flashed-off at the flash tank separator is then sent to be used as fuel in the TEG reboiler or compressor engine. Simply put, the pressure can only be dropped to a pressure that still exceeds the fuel gas pressure, allowing the collected methane gas to flow into the fuel system. Flash tank separators typically recover 90 percent of the total methane and approximately 10 to 40 percent of the total VOCs that would otherwise be vented to atmosphere. Methane emissions can also be controlled by taking the simple step of adjusting the rate that glycol is circulated in the system.

  In 2005, the EPA estimated that the installation of a flash tank separator, on average, resulted in 10 Mcfd (3,650 Mcf/yr) of methane gas captured for sale or use as fuel for each TEG dehydrator (typically a 90 percent reduction in methane emissions). And in 2009, the EPA reported that flash tank separators are installed on ***only***: 15 percent of the dehydration units processing less than 1 MMcfd; 40 percent of units processing 1 to 5 MMcfd; and between 65 and 70 percent of units processing more than 5 MMcfd.[262] Therefore, an emission control target still exists, especially for small dehydration units.

  The installation of a flash tank separator also improves the efficiency of downstream components (e.g. condensers) and reduces fuel costs by providing a fuel source to the TEG reboiler or compressor engine.[263]

- **Glycol Recirculation Pump**: Methane emissions are directly proportional to the glycol circulation rate. Circulating glycol at a rate that exceeds the operational need for removing water content from gas unnecessarily increases methane emissions. Glycol circulation rates are typically set at the maximum to account for peak throughput. Gas pressure and flow rate decline over time, requiring the glycol circulation rate to be adjusted to meet operational need. Optimizing the glycol circulation merely requires an engineering assessment and a field operating adjustment. If the glycol dehydration unit includes a condenser, methane emissions can be collected and used for fuel or destroyed, rather than being vented to atmosphere.

  In 2005, the EPA estimated that optimizing the glycol circulation rate could result in a wide range of methane capture from 1 to 100Mcfd (18,250 Mcf/yr using a median estimate of 50 Mcfd). [264]

[262] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

[263] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

- **Condensers**: Some glycol reboilers have condensers to recover natural gas liquids and reduce VOCs and HAPs. However, condensers do not capture methane (because it is a non-condensable gas); therefore, the addition of a condenser does not reduce methane emissions. When condensers are installed, methane gas is typically vented to atmosphere. Alternatively, this methane gas (called "skimmer gas") can be routed to the reboiler firebox or other low-pressure fuel gas systems.[265] In 2005, the EPA estimated that rerouting glycol skimmer gas could result in an average methane capture of 21 Mcfd (7,665 Mcf/yr). [266]
- **Electric Pump vs. Energy-Exchange Pumps:** Historically, gas-assisted glycol pumps have been used. Where there is an electric supply, the gas-assisted glycol pumps can be replaced with an electric pump. Gas-assisted pumps are driven by the expansion of the high-pressure gas entrained in the rich glycol that leaves the contactor, supplemented by the addition of untreated high-pressure wet (methane rich) natural gas. The high-pressure gas drives pneumatic pumps. Much like pneumatically operated valves, pneumatically operated pumps vent methane.

  In 2007, the EPA estimated that between 360 and 36,000 Mcf/yr in methane emission reductions could be achieved by installing an electric pump to replace the natural gas driven glycol energy exchange pump; the wide range in methane emission reductions is a function of the large variation in equipment sizes.[267]

In 2007, EPA estimated the total potential emission reductions at any given glycol dehydration unit is a function of how many emission control solutions are installed. The total may range from 3,700-35,000 Mcf/year ($14.8K-$140K worth of gas leakage). In 2011, EPA estimated 38,000 Mcf/year ($152K).[268] Therefore, controlling methane emissions and other GHG emissions from dehydration units is good business.

However, despite the clear environmental and financial benefits, not all members of the oil and gas industry voluntarily invest in methane control options. Therefore, it is recommended that NYSDEC require operators to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made.

Recommendation No. 57: Natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

[264] The wide range in methane capture opportunity is a function of the dehydrator size, and how efficiently the operator previously optimized the glycol circulation rate.

[265] USEPA Natural Gas STAR, Reroute Glycol Skimmer Gas, PRO Fact Sheet No. 201, 2004.

[266] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[267] EPA Natural Gas STAR, Natural Gas Dehydration, Producers Technology Transfer Workshop, Durango Colorado, September 13, 2007.

[268] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

Diesel Engine Emission Control:

In 2009 AKRF recommended that diesel engines should be Tier 2 or higher. AKRF pointed out that "Tier 0" engines could be used, unless NYSDEC limited engines by certification type. Uncertified engines have extremely high emission rates for criteria pollutants such as particulate matter.

Additionally, AKRF recommended that diesel particle filters be installed on diesel engines to reduce particulate matter that has shown to aggravate respiratory systems and is known to be carcinogenic. More specifically AKRF recommended that all engines with a power output of 50 horsepower or greater be equipped with a diesel particle filter, either by the original engine manufacturer or by retrofit.

The 2011 RDSGEIS, Appendix 10 Proposed Supplementary Permit Conditions for HVHF, addressed most of AKRF's recommendations, by prohibiting Tier 0 engines, requiring Tier 2 engines in most cases, and requiring both Tier 1 and Tier 2 engines to install emission controls. NYSDEC proposes that:

- ***No uncertified (i.e., EPA Tier 0) drilling or hydraulic fracturing engines*** *will be used for any activity at the well sites;*
- ***The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both particulate traps (CRDPF [Continuously Regenerating Diesel Particulate Filters]) and SCR [Selective Catalytic Reduction] controls****. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence; and*
- ***The completion equipment engines will be limited to EPA Tier 2 or newer equipment. Particulate traps will be required for all Tier 2 engines****. SCR control will be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence [emphasis added].*[269]

NYSDEC estimates that 25% of the engines may be Tier 1 engines, and to ensure compliance with National Ambient Air Quality Standards (NAAQS) it requires the engine to be equipped with both CRDPFs and Selective Catalytic Reduction controls.

While NYSDEC has proposed a number of improvements for diesel engine emission control, the RDSGEIS did not assess whether Tier 1 engines could be eliminated altogether.

Recommendation No. 58: The SGEIS should examine whether it is possible to eliminate Tier 1 engine use. Further examination of AKRF's recommendation to prohibit Tier 1 engine use is warranted.

[269] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109 and Appendix 10, Attachment A, Condition 9-11.

Leak Detection & Repair Program:

In 2009 HCLLC recommended that NYSDEC require Leak Detection and Repair (LDAR) programs including acoustic detectors and infrared technology to detect odorless and colorless leaks. Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs.

Methane gas leaks can occur from numerous locations at gas facilities—valves, drains, pumps, threaded and flanged connections, pressure relief devices, open-ended valves and lines, and sample points—as gas moves through equipment under pressure. These leaks are called "fugitive emissions."

Fugitive emissions from equipment leaks are unintentional losses of methane gas that may occur due to normal wear and tear, improper or incomplete assembly of components, inadequate material specifications, manufacturing defects, damage during installation or use, corrosion, or fouling.[270]

Because methane is a colorless, odorless gas, leaks often go unnoticed. Historically, leak checks were only performed on equipment components when they were first installed, using a soap bubble test or hand held sensor, to ensure the installation was leak tight. After installation leaks were not typically monitored or repaired unless they became a significant safety hazard. For example, a significant gas leak would be repaired if area, building, or employee monitors set off alarms or if olfactory, audible, or visual indicators observed by facility employees identified the leak. Under these circumstances, the leaks had usually become an obvious safety concern. As a result, methane leaks at outdoor facilities and unmanned facilities often went undetected for long periods of time.

Fugitive emission control is a two-part process that includes: (1) a monitoring program to identify leaks and (2) a repair program to fix the leak. Monitoring program type and frequency is a function of the type of component, and how the component is put to use. In most cases, monitoring programs can be intermittently scheduled at a certain frequency (e.g. monthly or quarterly) to identify leaking equipment. However, permanent leak sensors may be required to detect chronic leakers.[271]

There are many different monitoring tools that can be used to identify leaks, including electronic gas detectors, acoustic detectors, ultrasound detectors, flame ionization detectors, calibrated bagging, high volume sampler, end-of-pipe flow measurement, and infrared leak detection. Once leaks are identified, the operator can evaluate what is causing the leak and develop a replacement or repair program to mitigate the leak.

For example, a hand held infrared camera can be used as a screening tool to detect emissions that are not visible to the naked eye. An infrared camera produces images of gas leaks in real-time. [272] It is capable of identifying methane leaks, but cannot quantify the amount of the leak. Infrared cameras produce photos that show methane gas leaks.

Once a leak is identified, and a more quantitative leak flow rate determination is needed, other measurement devices such as Hi-Flow Samplers, Vent-Bag Methods, and Anemometers may be used.[273] Hi-Flow Samplers capture the entire leak, measuring the leak rate directly for leaks up to 10 cubic feet per

[270] USEPA, Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry, 2009.

[271] Squarek, J. (Canadian Association of Petroleum Producers), Layer, M. (Environment Canada) and Picard, D. (Clearstone Engineering Ltd.), Development of a Best Management Practice in Canada for Controlling Fugitive Emissions at Upstream Oil and Gas Facilities, 2005.

[272] Snider, P., Advanced Well Completion Technology to Reduce Methane Emissions and Use of Infared Cameras for Leak Detection, Global Forum on Flaring and Venting Reduction and Natural Gas Utilisation, 2008.

[273] Heath, M.W., Leak Detection and Quantification of Fugitive Methane Emissions at Natural Gas Facilities, 2009.

minute (cfm), providing leak flow rate and concentration data. [274] Toxic Vapor Analyzers and acoustic leak detection systems are other methods to identify methane leaks.[275]

Fugitive emissions management is an ongoing commitment, not a one-time initiative. The potential for fugitive equipment leaks will increase as facilities age. Successful fugitive emission control plans require trained personnel, emissions testing equipment, and performance tracking systems.

In 2009, the EPA examined the profitability of repairing equipment leaks at oil and gas facilities and found that leak repair is not only an important air pollution control and safety measure, but also is a profitable investment.[276] EPA reports that fugitive emissions control provides numerous benefits including: reduced maintenance costs and downtime, improved process efficiency, a safer work environment, a cleaner environment, and resource conservation.

The 2011 RDSGEIS acknowledges the potential impact of gas leaks, and requires a Leak Detection and Repair Program to be included in the operator's GHG Mitigation Plan.

> *Because the production phase is the greatest contributor of GHGs and in an effort to mitigate VOC and methane leaks during this phase, the* ***Department proposes to require, via permit condition and/or regulation, a Leak Detection and Repair Program would include as part of the operator's greenhouse gas emissions impacts mitigation plan which is required for any well subject to permit issuance under the SGEIS*** *[emphasis added].*[277]

The 2011 RDSGEIS specifies the minimum requirements for a Leak Detection and Repair Program.

> ***The Leak Detection and Repair Program within the greenhouse gas emissions impacts mitigation plan would contain the following minimum requirements****.*
>
> - *There would be an ongoing site inspection for readily detected leaks by sight and sound whenever company personnel or other personnel under the direction of the company are on site. Anytime a leak is detected by sight or sound, an attempt at repair should be made. If the leak is associated with mandated worker safety concerns, it should be so noted in follow-up reports;*
> - *Within 30 days of a well being placed into production and at least annually thereafter, all wellhead and production equipment, surface lines and metering devices at each well and/or well pad including and from the wellhead leading up to the onsite separator's outlet would be inspected for VOC, methane and other gaseous or liquid leaks. Leak detection would be conducted by visible and audible inspection and through the use of at least one of the following: 1) electronic instrument such as a forward looking infrared camera, 2) toxic vapor analyzer, 3) organic vapor analyzer, or 4) other instrument approved by the department;*
> - *All components noted above that are possible sources of leaks would be included in the inspection and repair program. These components include but are not limited to: line heaters, separators, dehydrators, meters, instruments, pressure relief valves,*

[274] http://www.heathus.com/_hc/index.cfm/about-us/vision

[275] Methane to Markets, Reducing Methane Emissions through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[276] Methane to Markets, Reducing Methane Emissions Through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[277] 2011 NYSDEC, RDSGEIS, Page 7-114 .

vents, connectors, flanges, open-ended lines, pumps and valves from and including the wellhead up to the onsite separator's outlet;

- *For each detected leak, if practical and safe an initial attempt at repair would be made at the time of the inspection, however, any leak that is not able to be repaired during the inspection may be repaired at any time up to 15 days from the date of detection provided it does not pose a threat to on-site personnel or public safety. All leaking components which cannot be repaired at detection would be identified for such repair by tagging. All repaired components would be re-inspected within 15 days from the date of the initial repair and/or re-repair to confirm, using one of the approved leak detection instruments, the adequacy of the repair and to check for leaks. The department may extend the period allowed for the repair(s) based on site-specific circumstances or it may require early well or well pad shutdown to make the repair(s) or other appropriate action based on the number and severity of tagged leaks awaiting repair; and*
- *Site inspection records would be maintained for a minimum period of 5 years. These records would include the date and location of the inspection, identification of each leaking component, the date of the initial attempt at repair, the date(s) and result(s) of any re-inspection and the date of the successful repair if different from initial attempt [emphasis added].*[278]

The RDSGEIS proposal to require an LDAR Program is a substantial improvement; however, a few changes to the proposed program are recommended:

- An LDAR inspection should be conducted at well/drillsite start-up, not 30 days after. It is best practice to construct and install equipment and test for leaks prior to operation. Equipment should not be operated for 30 days without completing this minimum standard of care.
- Quarterly testing with an infrared camera (as a screening method) should be required, instead of annual testing, as a minimum standard. If the infrared camera screening indicates a leak, the leak location, if clearly pin pointed, should be repaired. Or additional testing should be conducted using more sophisticated tools (described above) to pin-point the leak location, followed by a repair.
- Testing should include all equipment located on the drillsite. As proposed, the RSGEIS suggests the LDAR Program end at the separator's outlet. Equipment will be located downstream of the separator outlet, and prior to the connection the gas transit line that could potentially leak gas. Therefore, it is recommended that the LDAR Program be implemented for all equipment on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet.

Recommendation No. 59: The proposed LDAR Program should be revised to require: a drillsite LDAR inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the NYCRR, and be required for all natural gas operations, not just HVHF operations.

[278] 2011 NYSDEC, RDSGEIS, Page 7-115 and 7-116.

Cleaner Power and Fuel Supply Options:

In 2009, HCLLC and AKRF recommended that the SGEIS evaluate the use of cleaner engines and fuels.

In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, thus eliminating local diesel exhaust. This alternative would be particularly beneficial where operations are planned near sensitive receptors and in areas that already suffer from high air pollutant loading. Electric engines have the added benefit of quieter operation and less noise impact in urban and suburban settings.

In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel. Natural gas fired engines produce less air pollution that diesel engines. A natural gas supply should be available for all wells drilled on a multi-well drillsite, except the first well. Once the first well is drilled using diesel, subsequent wells can be drilled using the natural gas produced by that well to generate power. Smaller temporary gas processing units are available to process wellhead gas to the quality required for equipment use. The use of dual fuel engines would enable switching from diesel to natural gas once it is available.

The use of electric and natural gas engines would result in reduced local pollutant emissions and overall GHG emissions (both grid power and natural gas have a lower carbon footprint than diesel) and generally would have associated cost savings given the reduced fuel transportation and storage needs (e.g. double-wall tanks) and the reduced risk of tank leakage and cleanup associated with the use of fuel gas produced on-site or electric power.

The 2011 RDSGEIS: The 2011 RDSGEIS did not examine cleaner power and fuel supply options. The RDSGEIS only briefly mentioned that electric engines and cleaner fuel options were recommended[279] but disregarded the recommendations as "unlikely to be practically implemented to any extent" due to the remote nature of the drillsites. This analysis is incomplete and fails to consider viable alternatives for mitigating air pollution.

Foremost, electric power is available in all suburban and urban areas of NYS, and is currently located in many rural areas as well to supply power to homes, farms and businesses.

Secondly, the use of natural gas-fired engines on a multi-well drillsite is a commonly used mitigation measure. While diesel engines are often used as the prime mover of power supply for rotary well drilling, natural gas or dual fuel (diesel/gas) engines are available to take advantage of cleaner fuel supplies.[280] EnCana, a gas producer, reports that natural gas-fired rigs reduce air pollution by 90% compared to diesel fired rigs.[281] Power can also be supplied to the drilling rig by a natural gas-powered reciprocating turbine that can generate electricity on site.

[279] 2011 NYSDEC, RDSGEIS, Page 6-144.

[280] www.naturalgas.org.

[281] EnCana 2005 Annual Report.

Recommendation No. 60: In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

18. Surface Setbacks from Sensitive Receptors

Background: The 2009 DSGEIS did not propose sufficient safety or quality-of-life surface setbacks from sensitive human and environment resource receptors. This problem persists in the 2011 RDSGEIS. Noise, traffic, odor, air, and water pollution impacts to sensitive receptors will be significant if the small setbacks proposed in the RDSGEIS are adopted.

Surface setbacks should be increased to mitigate significant impacts and to create a safe environment for the affected public. For example:

- Blowouts can eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. These pollutants can then be further transported in the subsurface or on the surface, creating a large area of contamination in a very short amount of time.
- Chemicals, fuels, and explosive charges (e.g. perforating guns) may be located at the drillsite and may pose hazards to the public, in addition to the flammable, explosive, and hazardous gases (e.g. hydrogen sulfide gas, benzene) that are produced from the well and associated equipment.
- The potential radius of impact for explosions, fire, and other industrial hazards should be considered. For example, the city of Forth Worth, Texas uses the International Fire Code as the basis for its minimum 600' setback from Barnett shale gas drilling operations.[282] Whereas, NYCRR only provides for a 100' setback from a home. 6 NYCRR § 553.2.
- High pressure hose leaks can spray industrial fluids off the drilling pad and onto surrounding properties or waters. The radius of contamination will depend on system pressure, shut-down reaction timing, wind speed, and other factors.

For example, in September 2009, 1,300 gallons of well chemicals were leaked during a hydraulic fracture treatment at the Cabot Heitsman 4H well located in Susquehanna Country, Pennsylvania, and flowed into the nearby Steven's Creek located more than 100 feet away, despite protections in place under the operator's required Pennsylvania PPC plan.[283]

Recommendation No. 61: The SGEIS should provide scientific and technical justification for each setback distance proposed to demonstrate how that distance is protective of the nearby sensitive receptor. A hazard identification analysis should be completed to assess the safe distance from human and sensitive environmental receptors to proposed shale gas drilling and HVHF operations. The analysis should assess blowout radius, spill trajectory, explosion hazards, other industrial hazards, fire code compliance, human health, agricultural health, and quality-of-life factors. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

While statewide minimum setbacks to protect human health, provide safe buffers, and protect the environment should be established, both the RDSGEIS and NYCRR should include a provision to allow local communities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics.

[282] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009.

[283] Cabot Oil & Gas Corporation, Engineering Study, for submittal to PADEP, In Response to Order dated September 24, 2009, prepared by URS Corporation for Cabot, October 9, 2009.

Recommendation No. 62: The SGEIS and NYCRR should allow local zoning authorities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics. The ability to improve local setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2011 RDSGEIS: The 2011 RDSGEIS proposes additional setbacks from aquifers, wells, and water bodies for HVHF operations, but does not establish additional setbacks from homes or public buildings.

NYSDEC does not provide scientific or technical justification in the RDSGEIS for the setback distances it has selected. Setbacks ranging from 150' to 2,000' are included in the RDSGEIS without justification for how or why those particular distances were selected or determined to be adequate to protect water resources.

The 2011 RDSGEIS proposes the following setbacks:

- **500' setback from primary and principal aquifers**. However, for principal aquifers, drilling and HVHF operations can occur within that 500' buffer with additional review, and for both primary and principal aquifers the setback distance will be reconsidered in two years in a yet to be determined process.

  Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing).[284]

  For at least two years from issuance of the first permit for high-volume hydraulic fracturing, proposals for high-volume hydraulic fracturing at any well pad within 500 feet of principal aquifers, would require (1) site-specific SEQRA determinations of significance and (2) individual State Pollutant Discharge Elimination System (SPDES) permits for stormwater discharges. The Department would re-evaluate the necessity of this approach after two years of experience issuing permits in areas outside of the 500-foot boundary.[285]

- **2,000' setback from a public water supply**, unless a shale gas well is located within 1000' of a subsurface water supply designated by the New York City Department of Environmental Protection (NYCDEP). However, these setbacks will be reconsidered in three years in a yet to be determined process.

  The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing).[286]

  The Department proposes that site-specific environmental assessments and SEQRA determinations of significance be required for … any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure.[287]

[284] 2011 NYSDEC, RDSGEIS, Page 1-17.
[285] 2011 NYSDEC, RDSGEIS, Page 1-18.
[286] 2011 NYSDEC, RDSGEIS, Page 3-15.
[286] 2011 NYSDEC, RDSGEIS, Page 3-16.
[287] 2011 NYSDEC, RDSGEIS, Page 3-15.

Recommendation No. 63: The process for revising the 500' setback from primary and principal aquifers and the 2,000' setback from a public water supply in two and three years, respectfully, is unclear. NYSDEC should clarify the review process, including an explanation of its plans for public review and comment. NYSDEC should revise its regulations at 6 NYCRR § 617.4(b) to provide that the siting of any oil or gas well within 500' of a primary aquifer or within 2,000 of a public water supply is a Type I action.

- **500' setback from a private water well**.

> *The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 500 feet of private drinking water wells or domestic uses springs, unless waived by the owner.*[288]

The RDSGEIS provides no rationale as to why a public water supply would be afforded a 2,000' setback, while a private water well would only be afforded at 500' setback.

Recommendation No. 64: The SGEIS should examine whether waivers to the 500' private water well setback comport with federal law and the requirement to protect Underground Sources of Drinking Water (USDWs). The SGEIS should provide technical justification for any reduction in this setback, and should not allow a private well owner to reduce the setback such that it poses a risk to its water supply, as well as other user in the area. Private land owners should not be allowed to waive setbacks from private water wells and adversely affect the water quality of neighboring wells.

- **150' setback from a stream, storm drain, lake, or pond**.

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.*[289]

The 150' setback language conflicts with the 2,000' setback language above, because it allows a closer setback from lakes, rivers and streams than from a public water supply. It is not clear which lakes, rivers, and streams would be protected by the 150' setback, and which would be protected by a 2,000' setback.

On October 3, 2011 Pennsylvania Governor Corbett announced plans to implement the Marcellus Shale Advisory Commission recommendation to increase the setback distance for wells near streams, rivers, ponds and other bodies of water to at least 300'.[290] An increased set back to at least 300' should also be considered by NYS.

[288] 2011 NYSDEC, RDSGEIS, Page 7-76.

[289] 2011 NYSDEC, RDSGEIS, Page 7-76.

[290] Pennsylvania Office of the Governor, News Release, Governor Corbett Announces Plans to Implement Key Recommendations of Marcellus Shale Advisory Commission, October 3, 2011.

Recommendation No. 65: The conflicting language between the 150' setback requirement and 2,000' setback requirement for lakes, rivers, and streams needs to be resolved in both the SGEIS and the NYCRR. As drafted, neither the RDSGEIS nor the NYCRR are clear which lakes, rivers, and streams would be protected by the 150' setback, and which would be protected by a 2,000' setback. NYSDEC should indicate whether it intends to apply the 150' setback only to surface water resources that are not actual or potential public drinking water supplies. NYSDEC should also explain whether the 150' set back is sufficient to protect those water resources, or whether this setback should be increased. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

- **4,000' setback from NYC and Syracuse watersheds**.

Accordingly, the Department recommends that regulations be adopted to prohibit high-volume hydraulic fracturing in both the NYC and Skaneateles Lake watersheds, as well as in a 4,000 -foot buffer area surrounding these watersheds, to provide an adequate margin of safety from the full range of operations related to high-volume hydraulic fracturing that extend away from the well pad. The Department also is presenting this proposal based on its consistency with the principles of source water protection and the "multi-barrier" approach to systematically assuring drinking water quality.[291]

Recommendation No. 66: The 4,000' setback from NYC and Syracuse watersheds should be added to the proposed regulatory revisions for operations associated with HVHF at 6 NYCRR § 560.4. The SGEIS and NYCRR should also clarify if activities associated with HVHF drilling and completions will be prohibited underneath the watershed as well as on the surface.

NYSDEC has not provided engineering or scientific justification for the setback distances it has selected, other than a brief assessment of the setbacks that are allowed in other states. NYSDEC ultimately selected setbacks that are not as protective as those identified by the agency's consultants. For example, the RDSGEIS, states:

> *The required setbacks from surface water supplies in other states reviewed by Alpha vary between 100 and 350 feet.*[292]

NYSDEC's consultants collected information that shows a more protective 350' setback is in use in other states; however, NYSDEC concludes that only a 150' setback will be required. This is less than half the distance of the most protective standard found by NYSDEC's consultants, and the 150' setback can be further reduced at NYSDEC's discretion based on a site-specific SEQRA review:

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.*[293]

[291] 2011 NYSDEC, RDSGEIS, Page 7-56.

[292] 2011 NYSDEC, RDSGEIS, Page 7-76.

[293] 2011 NYSDEC, RDSGEIS, Page 7-76.

Of note, the RDSGEIS does not address setbacks from homes or public buildings. The RDSGEIS merely requires the operator to document the distance from the proposed drilling and HVHF operations to "…any residences, occupied structures or places of assembly within 1,320 feet."[294] However, no new setback is established for homes or public buildings, other than required by current regulations.

NYCRR Proposed Revisions: The new setbacks proposed in the RDSGEIS are codified in regulation at 6 NYCRR §560.4. These setbacks would apply only to wells that undergo HVHF. NYSDEC does not explain why these setbacks would not apply to all oil and gas well drilling in NYS, despite the fact that 6 NYCRR § 553.2 (Well Surface Restrictions) applies to all NYS oil and gas wells. NYSDEC has not justified its limiting of new setback increases to HVHF wells only.

Recommendation No. 67: The setback increases proposed in the RDSGEIS should apply to all oil and gas drilling in NYS and should be codified at 6 NYCRR § 553.2.

The existing NYCRR allows drilling, HVHF operations, and production equipment to be located within 100' from an inhabited private dwelling and within 150' from a public building or area that may be used as a place of "resort, assembly, education, entertainment, lodging, trade, manufacture, repair, storage, traffic or occupancy by the public." The existing NYCRR also allows drilling, HVHF operations, and production equipment to be located within 50' from a public stream, river, or other body of water. There is no required setback from buildings or structures used for agriculture. 6 NYCRR § 553.2.

The proposed revisions to the NYCRR include 500' setbacks from primary aquifers, 2,000' setbacks from public water supplies, and 500' setbacks from private wells. Proposed 6 NYCRR § 560.4. However, these setbacks apply only to wells that undergo HVHF, and do not apply to all wells that undergo hydraulic fracturing operations in NYS.

NYSDEC's setback analysis does not take into account that directional drilling technology enables wells to be drilled to a bottom-hole location at 3-5 miles[295] away from a wellhead. In directional drilling, it is now common for the horizontal displacement of the bottom hole location to be several times the total vertical depth (TVD) of the well. For example, a well with a vertical depth of 5,000' could have a bottom hole horizontal displacement of 10,000-15,000' from the drill site, or more. A well with a vertical depth of 7,000' could have a bottom hole horizontal displacement of 14,000-21,000' from the drill site, or more. For example, in 1997, BP drilled a well to approximately 5,300' achieving a 33,182' horizontal displacement, meaning the wellhead was located over 6 miles away from the hydrocarbon target.[296] In 1997, a 6-mile horizontal displacement was a great feat; now, extended reach drilling (ERD) is commonplace in the industry, and wells are routinely drilled to hydrocarbon targets miles away from the wellhead.

Given the flexibility afforded by the fact that 640-acre spacing units may vary in shape, from square to rectangular, and that surface drillsites need not be located over the spacing unit, well operators utilizing directional drilling technology have a greater ability to select surface drillsite locations that optimize distance from sensitive public and private resources.

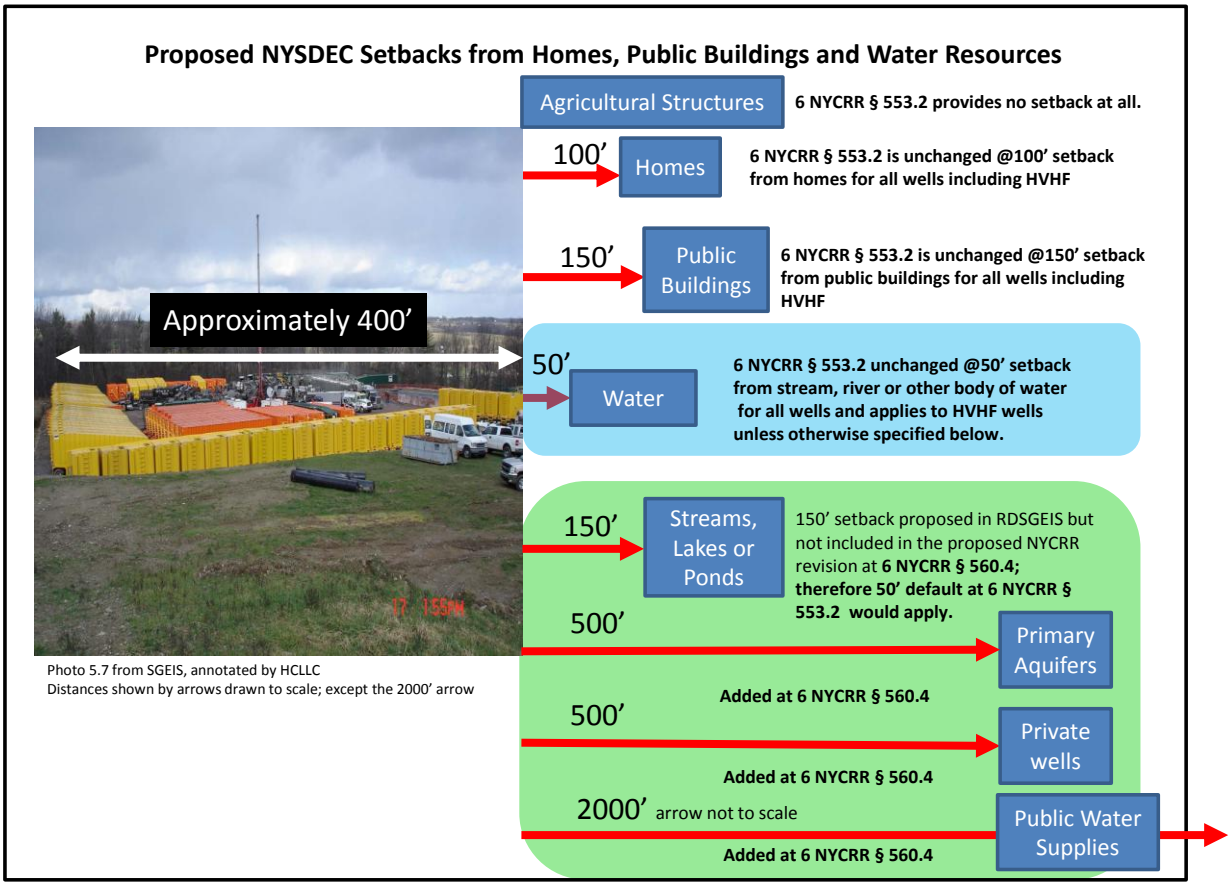
As shown in the figure below, the setbacks currently proposed in the RDSGEIS and in the NYCRR are inadequate. Shale drilling and HVHF operations within 100'-150' of homes and public buildings pose a direct safety risk, not to mention the health and quality of life impacts presented. NYSDEC is proposing

[294] 2011 NYSDEC, RDSGEIS, Page 3-10.

[295] Well step-out distance that can be achieved will depend on well depth.

[296] BP, Extended-Reach Drilling: Breaking the 10-km Barrier, 1997.

to allow shale drilling and HVHF operations to run 24 hours a day, 7 days a week, which will result in significant impacts to human health and quality of life—disrupting sleep, work, schooling, and recreational patterns for nearby residents.



By comparison, the local zoning setback requirements for Barnett Shale development implemented in the urban area of Fort Worth, Texas are substantially larger than those proposed for NYS.[297] As shown in the figure below, the required setback from a home is six times larger at 600', as compared to NYS' 100' setback. Additionally, Fort Worth, Texas has implemented setbacks of at least 300' from public buildings and 600' from schools, which is more than double what is proposed by NYSDEC.[298]

At a state level, Wyoming requires a minimum setback of 350' from "water supplies, residences, schools, hospitals, and other structures where people are known to congregate."[299] The below photograph shows the proximity of homes to a well pad in Pennsylvania, where a 200' minimum setback from homes is required.[300]

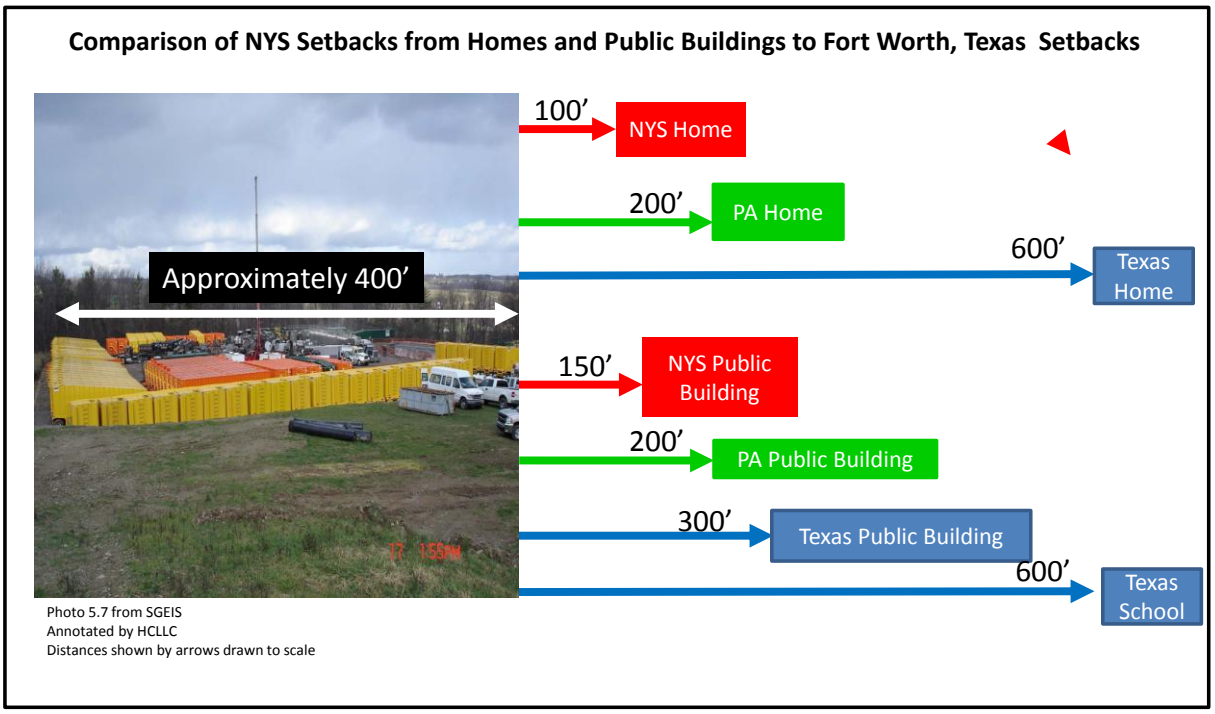
[297] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009; the Code of Ordinances of the City of Forth Worth § 15-36(A).

[298] The Code of Ordinances of the City of Forth Worth § 15-34(N)(7), § 15-36(A).

[299] Wyo. Admin. Code OIL GEN Ch. 3 § 22(b).

[300] Governor's Marcellus Shale Advisory Commission Report, Prepared for Governor Corbett of Pennsylvania, July 22, 2011.

The photo above shows homes within close proximity to shale drilling operations in Hopewell Township, Washington County, PA.



Recommendation No. 68: Improved setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Specifically, the SGEIS and NYCRR should be revised at 6 NYCRR § 553.2 to include the following minimum setbacks: homes, public buildings, and schools (1,320'; ¼ mile); private and public wells, primary aquifers, and other sensitive water resources (4,000'); and other water resources (660'; 1/8 mile). Additionally, NYSDEC should clarify the authority of local zoning authorities to establish minimum setbacks that are more protective than NYS' minimum standards in order for localities to address unique and site-specific local concerns and community characteristics.

In addition to the inadequate minimum setback requirements, the NYCRR allows an operator to move its surface location by 75' without obtaining a permit amendment. 6 NYCRR § 552.3(b). Absent NYSDEC and public review, a 75' adjustment is very significant, especially when setbacks as low as 50' to 150' are used. The regulations at 6 NYCRR § 552.3 explain that a 75' surface location adjustment is allowed, without any permit amendment process, to account for surface obstructions or topography. However, if an operator's due diligence and site planning during the original permit process include an examination of surface obstructions and topography, later adjustments should not be necessary.

Recommendation No. 69: The NYCRR should be revised at 6 NYCRR § 552.3 to allow the well location to be adjusted by 75' without a permit amendment only if all the statewide and local setback requirements are still preserved.

The proposed regulations that govern HVHF SPDES permits also suffer from inadequate minimum setback requirements. The revisions proposed to 6 NYCRR § 750-3.3 include: a 4,000' setback from an unfiltered water supply; a 500' setback from a primary aquifer; no operations within a 100-year floodplain; and a 2,000' setback from a public water supply, including wells, natural lakes, man-made impoundments, rivers and streams. However, neither the existing regulations nor the proposed revisions to 6 NYCRR § 750-3.3 include setbacks from streams, rivers, or other bodies of water that are not specifically designated as public water supplies. Thus, HVHF operations potentially could be as close as 50' to streams, rivers, or other bodies of water, based on 6 NYCRR § 553.2. Also, the proposed regulations do not require a minimum setback of HVHF operations from private wells.

Further inconsistency is introduced in the proposed revisions to 6 NYCRR § 750-3.21, which prohibit HVHF operations within 100' of a wetland. While this setback requirement is recognized in the RDSGEIS,[301] the proposed revisions to 6 NYCRR § 553.2 and 6 NYCRR § 560.4 do not include a parallel requirement. These sections of the regulations should be revised to include a wetland setback.

Recommendation No. 70: The NYCRR should be revised at 6 NYCRR § 553.2 to include a wetland setback of at least 100' as described in the RDSGEIS.

The proposed revisions to 6 NYCRR § 750-3.21(f)(3) do not authorize the issuance of a SPDES permit for HVHF operations within 150' of storm drains, lakes, ponds, and perennial or intermittent streams, which conflicts with the 50' setback established at 6 NYCRR § 553.2. There remains confusion about which setbacks would be applied to lakes, ponds, and perennial or intermittent streams and rivers.

Recommendation No. 71: The NYCRR should be revised at 6 NYCRR § 750-3.3, 6 NYCRR § 750-3.2, 6 NYCRR § 553.2, and 6 NYCRR § 560.4 to provide consistent setback requirements that are protective of water sources, including rivers, streams, lakes, and private water supplies.

NYCRR should be clear that the intent, as stated in the RDSGEIS, is to measure setbacks from the edge of the drillsite, and to attempt to center wells on the drillsite to maximize the distance from the well to the drillsite edge.

Recommendation No. 72: NYCRR and the SGEIS should clarify that setbacks are measured from the edge of the drillsite. Wells should be centered on the well pad and should be set back at least 100' from the pad edge, to maximize well setbacks from sensitive receptors.

[301] 2011 NYSDEC, RDSGEIS, Page 2-34.

19. Disposal of Drilling & Production Waste and Equipment Containing Naturally Occurring Radioactive Material (NORM)

Background: In 2009, HCLLC made recommendations to NYSDEC on best practices for disposal of drilling and production waste and equipment containing Naturally Occurring Radioactive Materials (NORM). NORM includes uranium, thorium, radium, and lead-210 and their decay products.[302] Additionally, radon, a component of natural gas, decays into radioactive polonium.

NORM can be brought to the surface in a number of ways during drilling, completion, and production operations:

- **Drilling**: Drill cuttings containing NORM are circulated to the surface.
- **Completion**: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- **Production**: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

In January 2011, NYSDEC's consultant, Alpha Geoscience, agreed that the disposal of waste containing NORM is an important issue that should be addressed in the SGEIS. Alpha Geoscience's review of HCLLC's recommendations on NORM concluded that:

> *Harvey Consulting's recommendation to analyze practices for NORM testing, NORM treatment, and NORM disposal appears to be complete and well-researched. The review presents a concise analysis of practices involving the testing for and the treatment and disposal of NORM.*
>
> *Harvey Consulting's review of the dSGEIS's content regarding NORM is supported by a range of reliable sources. References include the EPA's website, USGS fact sheets, Texas Railroad Commission regulations, and a publication by Argonne National Laboratory.*[303]

Alpha Geoscience recommended that the SGEIS include a detailed analysis of NORM testing, treatment, transportation, and disposal methods:

> *Alpha suggests that **it may be useful to operators if the SGEIS includes NYSDEC's detailed analyses of NORM testing, treatment, transportation, and disposal**. This information may prove useful to the operator for developing handling and disposal plans [emphasis added].*[304]

[302] USEPA Oil and Gas Production Wastes, NORM, http://www.epa.gov/radiation/tenorm/oilandgas.html.

[303] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 9-11.

[304] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 12.

Yet, Alpha Geoscience recommended against adopting specific regulations to formalize NORM testing, treatment, transportation, and disposal requirements in NYS; instead, Alpha Geoscience recommended that NYSDEC "consider" having "temporary guidelines:"

> ***Alpha suggests that NYSDEC consider having temporary guidelines regarding NORM*** *in place, to clarify expectations and requirements for operators prior to the commencement of operations. This also would be helpful to operators for the design of handling and disposal plans [emphasis added].*[305]

HCLLC disagrees with Alpha Geoscience's recommendation for temporary NORM disposal guidelines. The requirements for testing, treatment, transportation, and disposal of NORM should be formalized in NYCRR. The rules should be clear to industry and the public, and enforceable by NYSDEC.

The 2009 DSGEIS acknowledged that drilling and production waste and equipment may contain NORM. NYSDEC reports that the Marcellus Shale contains Uranium-238 and Radium-226, and this NORM may be present in drill cuttings, produced water, and stimulation treatment waste.[306] NYSDEC identified Radium-226 as the most significant NORM of concern, because it is water soluble and has a half-life of 1,600 years.[307] Radiation pathways can include external gamma radiation, ingestion, inhalation of particulates, and radon gas.[308]

In 2009, HCLLC recommended that the SGEIS address the potential for equipment scale and sludge to contain high concentrations of NORM. HCLLC explained that equipment (water lines, flow lines, injection wellheads, vapor recovery units, water storage tanks, heaters/treaters, and separators)[309] used to process natural gas and produced water containing NORM can become coated with radium scale and sludge deposits.[310] Scale precipitates from produced water when it is brought to the surface, cooled to lower temperatures, and subject to lower pressures.[311] The most common form of scale is barium sulfate, which readily incorporates radium in its structure. HCLLC noted that, because E&P waste is exempt from the federal Resource Conservation and Recovery Act (RCRA),[312] it is critical that states establish clear best practice requirements for handling E&P waste, especially for NORM found in equipment scale and sludge. HCLLC pointed out that other oil and gas states, such as Texas and Louisiana, have adopted stringent NORM regulations, including: occupational dose control, surveys; testing and monitoring; record keeping; signs and labeling; and treatment and disposal methods.[313]

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[305] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 11.

[306] 2009 NYSDEC, DSGEIS, Page 4-36.

[307] 2009 NYSDEC, DSGEIS, Page 6-129.

[308] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[309] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[310] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[311] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[312] Environmental Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA530-K-01-004, October 2002.

[313] 2009 NYSDEC, DSGEIS, Page 7-101.

The 2011 RDSGEIS: The 2011 RDSGEIS provided some improved data and acknowledged the risk of significant impacts from improperly disposed waste containing NORM. The RDSGEIS concluded that the NORM dataset is limited and there can be significant variability in NORM content. The 2011 RDSGEIS based its conclusions on data collected in other states; this data examined Marcellus Shale cuttings, produced water, and HVHF flowback.

However, the 2011 RDSGEIS still does not establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved in that it establishes radioactive limitations and testing in some cases, but testing is still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g. for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Recommendation No. 73: Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

Equipment Containing NORM: The 2011 RDSGEIS contains substantially improved requirements for equipment containing NORM, including a new radiation testing requirement and a treatment and disposal threshold limit. The RDSGEIS concludes that pipe scale and sludge (NORM buildup in equipment) can result in NORM concentrations that may have a significant adverse impact.

The 2011 RDSGEIS clarifies that NYSDOH will require the well operator to obtain a radioactive materials license for its facility when exposure rate measurements associated with scale accumulation in or on piping, drilling, and brine storage equipment exceeds 50 microR/hr[314] (μR/hr).[315] The RDSGEIS does not explain the origin of the 50 μR/hr limit; however, this limit has been used by a number of oil and gas producing states, including Texas[316] and Louisiana.[317]

[314] Microroentgens per hour (μR/hr) is a measurement of exposure from x-ray and gamma ray radiation in air.

[315] 2011 NYSDEC, RDSGEIS, Page 5-142.

[316] Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, Economic Regulation, Railroad Commission of Texas, Environmental Protection, Oil and Gas NORM.

[317] Louisiana Administrative Code, Title 33 LAC Part XV, Radiation Protection.

Presumably, equipment containing a radioactive concentration of less than 50 µR/hr would be disposed of in a NYS landfill; however, it is unclear if NYS' landfills are designed to accommodate waste containing radioactivity of up to 50 µR/hr.

Recommendation No. 74: NYSDEC should explain the origin of the 50 µR/hr limit, and explain how NYS determined that this threshold is sufficiently protective for NYS. The SGEIS should explain where equipment containing a radioactive concentration of less than 50 µR/hr would be disposed (e.g. a NYS landfill), and whether this waste disposal method was designed for this waste handling purpose.

The RDSGEIS Chapter 7 (Section 7.7.2) proposes NORM testing (radiation survey) requirements:

> ***The Department proposes to require, via permit condition and/or regulation, that radiation surveys be conducted at specified time intervals for Marcellus wells developed by high-volume hydraulic fracturing completion methods on all accessible well piping, tanks, or other equipment that could contain NORM scale buildup.*** *The surveys would be required to be conducted for as long as the facility remains in active use. Once taken out of use no increases in dose rate are to be expected. Therefore, surveys may stop until either the site again becomes active or equipment is planned to be removed from the site. If equipment is to be removed, radiation surveys would be performed to ensure appropriate disposal of the pipes and equipment. All surveys would be conducted in accordance with NYSDOH protocols. The NYSDOH's Radiation Survey Guidelines and a sample Radioactive Materials Handling License are presented in Appendix 27. The Department finds that existing regulations, in conjunction with the proposed requirements for radiation surveys, would fully mitigate any potential significant impacts from NORM [emphasis added].*[318]

NYSDEC's proposal to require NORM testing (radiation surveys) for HVHF wells and equipment is an important improvement. This proposed mitigation measure is effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 65, requires:

> *65) Periodic* ***radiation surveys must be conducted at specified time intervals*** *during the production phase for Marcellus wells developed by high-volume hydraulic fracturing completion methods. Such surveys must be performed on all accessible well piping, tanks, or equipment that could contain NORM scale buildup. The surveys must be conducted for as long as the facility remains in active use. If piping, tanks, or equipment is to be removed, radiation surveys must be performed to ensure their appropriate disposal. All surveys must be conducted in accordance with NYSDOH protocols [emphasis added].*[319]

However, this permit condition is only applied to HVHF wells and equipment. NORM can accumulate in all oil and gas equipment; therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the radiation testing frequency and method be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[320] Furthermore, Dr. Glenn Miller and Dr.

[318] 2011 NYSDEC, RDSGEIS, Page 7-119.

[319] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[320] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

Ralph Seiler recommended that radiation testing not be limited to radium. For example, Dr. Ralph Seiler points out in his comments that while NYSDEC has identified Radium (Ra) as a contaminant of concern, NYSDEC has overlooked the potential significant unmitigated impact of Polonium 210 (^{210}Po) accumulating in pipe scale as a byproduct of radon decay (natural gas contains radon).[321]

Recommendation No. 75: The requirement for radiation surveys should be codified in the NYCRR and applied to all oil and gas operations, not just HVHF operations. Radiation testing frequency and method should be specified to ensure that all potential radiation impacts are assessed and quantified. The proposed HVHF Permit Condition No. 65 could serve as a starting point for the NYCRR revisions.

Produced Water and Flowback Wastewater NORM: In 2009, HCLLC pointed out that water produced from wells can be rich in chloride, which enhances the solubility of other elements, including the radioactive element radium.[322] HCLLC also noted that flowback wastewater can contain NORM.

In 2009, NYSDEC reported that it had insufficient data on NORM in produced water and flowback wastewater, but acknowledged that NORM is present and is known to be found in elevated levels in produced water.

The Department of Energy (DOE) explains the presence of NORM in produced water:

> ***Because the water has been in contact with the hydrocarbon-bearing formation for centuries, it contains some of the chemical characteristics of the formation and the hydrocarbon itself.*** *It may include water from the reservoir, water injected into the formation, and any chemicals added during the production and treatment processes. Produced water is also called "brine" and "formation water."* ***The major constituents of concern in produced water are****:*
>
> - *Salt content (salinity, total dissolved solids, electrical conductivity)*
> - *Oil and grease (this is a measure of the organic chemical compounds*[323]
> - *Various natural inorganic and organic compounds or chemical additives used in drilling and operating the well*
> - ***Naturally occurring radioactive material (NORM).***
>
> *The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological host formation, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir [emphasis added].*[324]

[321] Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[322] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[323] In addition to the major constituents of concern listed by DOE for produced water, Dr. Glenn Miller notes that both the gasoline and diesel range hydrocarbon fractions should be monitored, since they are more soluble than heavy hydrocarbons.

[324] United States Department of Energy, Produced Water Management Information System, http://www.netl.doe.gov/technologies/pwmis/intropw/index.html.

Since 2009, NYSDEC gathered additional information and improved the 2011 RDSGEIS to acknowledge and quantify the potential adverse impact of produced water radioactivity. Although NYSDEC's research shows that flowback waste may not contain significant concentrations of radioactive material, NYSDEC acknowledges it has a limited dataset, and proposes radiation surveys for both types of wastewater (flowback and produced water).

NYSDEC's proposal to require NORM testing (radiation surveys) for flowback and production brine is a significant improvement to the 2011 RDSGEIS, and this proposed mitigation measure was effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 64, requires:

> *64) Flowback water recovered after high-volume hydraulic fracturing operations must be tested for NORM prior to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for NORM prior to removal.*[325]

However, this permit condition is only applied to HVHF wells and equipment. NORM can be present in all flowback wastewater, including hydraulic fracture treatments less than 300,000 gallons, and produced water from wells that are not subject to HVHF treatments. Therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the NORM testing method and frequency be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[326]

Recommendation No. 76: The requirement to test produced water (production brine) and flowback wastewater (waste from hydraulic fracturing operations) should by codified in the NYCRR and applied to all oil and gas operations. NORM testing frequency and method should be specified. Proposed HVHF Permit Condition No. 64 could serve as a starting point for NYCRR revisions.

The RDSGEIS proposes to allow flowback wastewater and produced water to be disposed of at a Publically Owned Treatment Works (POTW), as long at the influent concentration of radium-226 (as measured prior to admixture with POTW influent) is limited to 15 pCi/L,[327] or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7.

> *The Department proposes to require, as a permit condition, that the permittee demonstrate that it has a source to treat or otherwise legally dispose of wastewater associated with flowback and production water prior to the issuance of the drilling permit.* ***Disposal and treatment options include publicly owned treatment works, privately owned high volume hydraulic fracturing wastewater treatment and/or reuse facilities, deep-well injection, and out of state disposal.***

[325] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[326] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[327] Picocuries per gram (pCi/g) is a measure of the radioactivity in one gram of a material. One picocurie is that quantity of radionuclide(s) that decays at the rate of 3.7 x 10-2 disintegrations per second.

> ***Flowback water and production water must be fully characterized prior to acceptance by a POTW for treatment****. Note in particular Appendix C. IV of TOGS 1.3.8, Maximum Allowable Headworks Loading. The POTW must perform a MAHW analysis to assure that the flowback water and production water will not cause a violation of the POTW's effluent limits or sludge disposal criteria, allow pass through of unpermitted substances or inhibit the POTW's treatment processes. As a result, the SPDES permits for POTWs that accept this source of wastewater will be modified to include influent and effluent limits for Radium and TDS, if not already included in the existing SPDES permit, as well as for other parameters as necessary to ensure that the permit correctly and completely characterizes the discharge.* ***In the case of NORM, anyone proposing to discharge flowback or production water to a POTW must first determine the concentration of NORM present in those waste streams to determine appropriate treatment and disposal options. POTW operators who accept these waste streams are advised to limit the***
>
> ***concentrations of NORM in the influent to their systems to prevent its inadvertent concentration in their sludge.*** *For example,* ***due to the potentially large volumes of these waste waters that could be processed through any given POTW, as well as the current lack of data on the level of NORM concentration that may take place, it will be proposed that POTW influent concentrations of radium-226 (as measured prior to admixture with POTW influent) be limited to 15 pCi/L, or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7.*** *As more data become available on concentrations in influent vs. sludge it is possible that this concentration limit may be revisited [emphasis added].*[328]

EPA data shows that produced water can contain 0.1 to 9,000 pCi/L of radium-226.[329] Therefore, it is reasonably foreseeable that there will be substantial volumes of wastewater that will exceed the 15 pCi/L POTW influent limit. NYSDEC has not proposed a waste treatment or disposal solution for wastewater that exceeds the 15 pCi/L POTW influent limit.

Recommendation No. 77: The SGEIS should examine treatment and disposal options, and capacity within NYS, for wastewater exceeding 15 pCi/L radiation.

Additionally, it is unclear if NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation. The Federal Safe Drinking Water standard is 5 pCi/L[330] (radium-226 and radium -228 combined).[331] The 5 pCi/L threshold was set because of the increased risk of cancer above this level. Because the RDSGEIS does not examine NYS' POTW's ability to treat incoming wastewater with 15 pCi/L radiation, it does not provide an estimate of the expected radiation level at the POTW effluent. Therefore, it is not clear whether POTW effluent discharge at a level greater than 5 pCi/L could end up in a drinking water supply, or how NYSDEC plans to monitor and ensure that this does not happen.

[328] 2011 NYSDEC, RDSGEIS, Page 6-58 and 6-59.

[329] USEPA Oil and Gas Production Wastes, Summary Table of Reported Concentrations of Radiation in TENORM, http://www.epa.gov/radiation/tenorm/sources.html#summary-table

[330] Measured as Radium 226 and Radium 228 combined.

[331] USEPA Federal Safe Water Drinking Water Standards for Radionuclides at http://water.epa.gov/drink/contaminants/index.cfm#List.

Recommendation No. 78: The SGEIS should examine whether NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation, and should predict the maximum effluent radiation level. The SGEIS should explain how NYSDEC will ensure that drinking water sources will not exceed 5 pCi/L radiation.

The 2011 RDSGEIS does not prohibit road spreading of waste; it deferred this decision to a yet-to-be determined future process outside the SGEIS review. Yet, other oil and gas producing states, such as Texas, specifically prohibit road spreading of waste containing NORM.[332] A study conducted by Argonne National Lab for the US Department of Interior (DOI) concluded that land spreading of diluted NORM waste presented the highest potential dose of exposure to the general public of all waste disposal methods studied.[333]

Most states dispose of wastewater using deep well injection or use it to enhance hydrocarbon recovery operations. Land disposal is not common for onshore operations. The Department of Energy reports that more than 98% of oil and gas wastewater from onshore operations is injected into underground disposal wells, which are regulated by EPA, or used for enhanced hydrocarbon recovery.[334] The 2009 DSGEIS explored produced water treatment and disposal options (e.g. injection wells, treatment plants, and road spreading),[335] but did not land on a best practice.

The 2011 RDSGEIS concludes there is not enough information available to allow for road spreading under a Beneficial Use Determination (BUD).[336] However, the RDSGEIS does not explicitly state that road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

Since the current BUD does not require an operator to test for NORM,[337] it is unclear how NORM testing at the well site will be integrated into the BUD process. The level of NORM, if any, that will be allowed in fluids used for road spreading is also unclear. The 2011 RDSGEIS does not examine the cumulative impact of spreading small amounts of NORM repeatedly over the same area. It is recommended that land and road spreading of produced water and other waste containing NORM be **prohibited**. Produced water containing NORM should be returned to the subsurface formation from which it came, or should be handled at an approved waste treatment plant.

Recommendation No. 79: The SGEIS should explicitly state that land and road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

[332] Texas Railroad Commission (TXRRC), 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632. "Disposal of Oil and Gas NORM Waste". The TCEQ has jurisdiction over the disposal of other NORM wastes.

[333] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[334] Argonne National Laboratory, Produced Water Volumes and Management Practices in the United States, Report Prepared for United States Department of Energy, Report No. ANL/EVS/R-09/1, 2009.

[335] 2009 NYSDEC, DSGEIS, Page 5-131.

[336] 2011 NYSDEC, RDSGEIS, Page 7-60.

[337] The example BUD application provided in Appendix 12 requires testing for calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil and grease, benzene, ethylbenzene, toluene and xylene, but not NORM.

The Environmental Protection Agency (EPA) identifies produced water pits (brine pits) as an outdated practice in cases where produced water contains NORM. If wastewater pond sediments pose a potential radiological health risk, tank sediments from wastewater stored in tanks also would pose a radiological health risk. EPA reports that:

> *Lined and/or earthen pits were previously used for storing produced water and other nonhazardous oil field wastes, hydrocarbon storage brine, or mining wastes. In this case, TENORM*[338] *in the water will concentrate in the bottom sludges or residual salts of the ponds.* ***Thus the pond sediments pose a potential radiological health risk****….produced waters are now generally reinjected into deep wells…No added radiological risks appear to be associated with this disposal method as long as the radioactive material carried by the produced water is returned in the same or lower concentration to the formations from which it was derived [emphasis added].*[339]

Recommendation No. 80: The SGEIS should address testing of wastewater sediments, and explain the collection, transportation, treatment, and disposal methods for this potential radiological health risk.

Drill Cutting NORM: The 2011 RDSGEIS acknowledges the fact that drill cuttings can contain NORM, but makes a blanket assumption that the level of radiation from cuttings will be low. The RDSGEIS does not require site-specific testing to verify this assumption, nor does it preclude cuttings disposal in existing solid waste landfills. Instead, the RDSGEIS only recommends that the well operator consult with the landfill operator prior to drill cuttings disposal.

> *In New York State the* ***NORM in cuttings is not precluded by regulation from disposal in a solid waste landfill****,* ***though well operators should consult with the operators*** *of any landfills they are considering using for disposal regarding the acceptance of Marcellus Shale drill cuttings by that facility [emphasis added].*[340]

The 2011 RDSGEIS is unclear about the environmental and human health protections that would be achieved via the landfill consultation process. Appendix 10, Proposed EAF Addendum Requirements for HVHF, requires the operator to specify where it plans to dispose of cuttings, and requires evidence that the cuttings will go to a Part 360 solid waste landfill. However, the RDSGEIS does not provide scientific or engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM.

NYSDEC acknowledges significant uncertainty about the NORM content of drill cuttings in Chapter 7, and raises questions as to whether there are sufficient data to fully assess NORM impacts at this time. The 2011 RDSGEIS states:

> ***Existing data from drilling in the Marcellus Formation*** *in other States, and from within New York for wells that were not hydraulically fractured,* ***shows significant variability in NORM content.*** *This variability appears to occur both between wells in different portions of the formation and at a given well over time. This makes it important that samples from wells in different locations within New York State are used to assess the extent of this variability.*

[338] TENORM is Technologically Enhanced Natural Occurring Radioactive Material.

[339] http://www.epa.gov/radiation/tenorm/oilandgas.html#disposalpast.

[340] 2011 NYSDEC, RDSGEIS, Page 5-129 and 5-130.

> ***<u>During the initial Marcellus development efforts, sampling and analysis would be undertaken in order to assess this variability</u>****. These data would be used to determine whether additional mitigation is necessary to adequately protect workers, the general public, and environment of the State of New York [emphasis added].*[341]

Yet, the 2011 RDSGEIS does not propose NORM mitigation measures. It does not require drill cuttings testing prior to disposal in the landfill, nor does it establish a maximum allowed NORM disposal threshold for safe long-term cuttings disposal in a landfill.

Recommendation No. 81: Drill cuttings should be tested for NORM prior to disposal in a landfill. A maximum allowed NORM threshold for drill cuttings disposal in the landfill should be clearly established and scientifically justified. Testing and threshold requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Waste exceeding the established NORM threshold should be handled under NYS' radioactive waste handling rules.

Chapter 5.2.4.2 of the 2011 RDSGEIS concludes that NORM content in drill cuttings is equivalent to background levels of radiation occurring naturally in the atmosphere. This conclusion is based on Geiger counter and gamma ray spectroscopy sampling methods.

Yet, Dr. Glenn Miller points out in his comments on the 2011 RDSGEIS[342] that gamma ray spectroscopy is insufficient to assess all radioactive constituents (e.g. polonium is radioactive and only a weak gamma ray emitter), and gamma ray measurements do not provide insight into the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate NORM when disposed. Dr. Miller concludes that NYS likely has underestimated the amount of NORM in drill cuttings, and recommends NYS require additional testing methods to verify total radiation levels and better understand the potential for drill cuttings to later oxidize, leach, and concentrate NORM when disposed. Additional work is needed to verify whether the disposal of drill cuttings containing NORM in existing NYS landfills is a best practice.

Recommendation No. 82: The SGEIS should provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, including lower concentrations of NORM that could cumulatively have a significant impact when stored in large volumes over long periods of time. The SGEIS should examine the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate radioactive materials within the landfill. If NYSDEC cannot provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, it should identify alternative collection, transportation, treatment, and disposal requirements.

NYCRR Proposed Revisions: Proposed Permit Condition No. 53 requires waste fluids be handled in accordance with 6 NYCRR § 554.1(c)(1); yet, this regulation does not specify the best practice for handling hydraulic fracturing fluid and other drilling and completion wastes. Instead, 6 NYCRR § 554.1(c)(1) merely provides a process for the applicant to submit a waste management plan. In 2009, HCLLC recommended revisions to this regulation; yet, none are proposed. The existing regulation states:

> *Prior to the issuance of 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* ***<u>sufficient quantities</u>*** *to be deleterious to the surrounding environment, the operator*

[341] 2011 NYSDEC, RDSGEIS, Page 7-119.

[342] Miller, G., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

> *must submit and receive approval for a plan for the environmentally safe and proper ultimate disposal of such fluids. For purposes of this subdivision, drilling muds are not considered to be polluting fluids. Before requesting a plan for disposal of such fluids, the department will take into consideration the known geology of the area, the sensitivity of the surrounding environment to the polluting fluids and the history of any other drilling operations in the area.* ***Depending on the method of disposal chosen by the applicant****, a permit for discharge and/or disposal may be required by the department in addition to the well-drilling permit. An applicant may also be required to submit an acceptable contingency plan, the use of which shall be required if the primary plan is unsafe or impracticable at the time of disposal [emphasis added].*

Terms such as "sufficient quantities" are ambiguous, providing operators and regulators large latitude in how they interpret the regulation. Regulations should specify technically and scientifically based thresholds and management practices.

Under 6 NYCRR § 554.1(c)(1), the waste disposal method is selected by the applicant, with no instruction on how to determine the best waste management practice. While recycling and the reuse of fracturing fluid are discussed in the RDSGEIS, there is no requirement in the proposed permit conditions to use this best practice. Furthermore, NYSDEC does not explain how it will oversee the recycling and reuse processes.

Recommendation No. 83: Revisions are needed to 6 NYCRR § 554.1(c)(1) to require a more robust waste management planning and oversight process, including detailed instructions on collection, testing, transportation, treatment, and disposal of waste.

20. Hydrogen Sulfide

Background: In 2009, HCLLC recommended that the NYCRR require operators to follow American Petroleum Institute Recommended Practice 49 (API RP 49) for Drilling and Well Servicing Operations Involving Hydrogen Sulfide, and API RP 55 for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide, to protect employees and the public.

The 2011 RDSGEIS: The 2011 RDSGEIS reports that Marcellus Shale operations in Pennsylvania have not produced substantial amounts of H_2S.[343] However, this conclusion is based on limited information from wells drilled only in Pennsylvania. These data do not confirm that H_2S will not be present initially or over time in NYS wells.

H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause serious health symptoms at elevated concentrations, and can be deadly at the higher concentrations found in some oil and gas wells.

The Occupational Safety and Health Administration (OSHA) recommends close monitoring of H_2S for human health and explosion mitigation:

> *Hydrogen Sulfide or sour gas (H2S) is a flammable, colorless gas that is toxic at extremely low concentrations. It is heavier than air, and may accumulate in low-lying areas. It smells like "rotten eggs" at low concentrations and causes you to quickly lose your sense of smell. Many areas where the gas is found have been identified, but pockets of the gas can occur anywhere.*
>
> *Iron sulfide is a byproduct of many production operations and may spontaneously combust with air.*
>
> *Flaring operations associated with H_2S production will generate Sulfur Dioxide (S02), another toxic gas.*
>
> *Active monitoring for hydrogen sulfide gas and good planning and training programs for workers are the best ways to prevent injury and death.*[344]

The American Conference of Governmental Industrial Hygienists recommends a Threshold Limit Value of 10ppm and a short-term exposure (STEL) limit of 15 ppm, averaged over 15 minutes, for the action level indicating the need for respiratory protection.[345] While workers may be afforded respiratory protection, nearby members of the public do not have routine access to respiratory protection and monitoring systems. Routine, standardized testing should also be in place to ensure public health and safety.

A 300 ppm concentration of H_2S is considered by the American Conference of Governmental Industrial Hygienists as Immediately Dangerous to Life and Health.

[343] 2011 NYSDEC, RDSGEIS, Page 5-138.

[344] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/h2s_monitoring.html.

[345] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html.

> *In low concentrations, H_2S sometimes can be detectable by its characteristic odor; however, the smell cannot be relied upon to forewarn of dangerous concentrations (greater than 100ppm) of the gas because it rapidly paralyzes the sense of smell due to paralysis of the olfactory nerve. A longer exposure to the lower concentrations has a similar desensitizing effect on the sense of smell.*
>
> *It should be well understood that the sense of smell will be rendered ineffective by hydrogen sulfide, which can result in an individual failing to recognize the presence of dangerously high concentrations. Exposure to hydrogen sulfide causes death by poisoning the respiratory system at the cellular level.* [346]

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public.

While H_2S may not be initially present at a drillsite, the operator must remain vigilant in monitoring for H_2S over time, because sulfate reducing bacteria and other forms of acid producing bacteria can generate H_2S in the reservoir, such that H_2S concentrations elevate over time. Increasing levels of H_2S is a common problem in waterflooding operations in oil and gas fields. Biocides are typically used to mitigate bacteria growth; however, sometimes biocides are not successful.

Biocide use and close monitoring of H_2S early in field development is an important mitigation measure, because once elevated H_2S is present it is difficult to control. Industry anticipates H_2S will be a future concern in operations requiring large volumes of water for HVHF treatments, especially where treatment fluid is recycled, as planned in NYS. A 2010 Apache Corporation paper summarizes the problem:

> ***One of the most severe threats in recycling waters for fracs is the control of bacteria (Tischler, 2009), including sulfate reducing bacteria (SRBs) and other forms such as acid producing bacteria (APB), iron fixing bacteria and slime formers. SRBs have created souring of some conventional reservoirs from injection of waters, both produced and semi-fresh, which have established a presence in the reservoirs and create H_2S gas and iron sulfide problems.*** *Local well fouling problems are common where SRBs are spiked into the formation from drilling or completion fluids. This type of H_2S occurrence may cause local corrosion…in shale, however, the effect of uncontrolled bacteria is a general unknown, given the extremely large volumes of surface water used for slick water fracturing. For this reason, recycling of the water may seed all waters with bacteria and/or concentrate the bacteria; thus bacterial control is a necessity [emphasis added].* [347]

Due to the potential close proximity of Marcellus Shale operations to the public, a robust initial monitoring program should be instituted to determine H_2S concentrations in Marcellus Shale gas throughout NYS. As described in American Petroleum Institute Recommended Practices 49 and 55, monitoring frequency can be adjusted over time as site-specific information is obtained. Initial sampling should be conducted at each drillsite, with at least monthly sampling thereafter.

[346] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html

[347] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010, Page 30.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing, Permit Condition No. 25 includes a requirement to conform with API RP 49; however, there is no requirement for operators to conform with API RP 55, which applies after the well is drilled, during production operations.

NYCRR Proposed Revisions: As a control measure, when H_2S is present, the proposed regulations at 6 NYCRR § 560.6(c)(28) require the venting of any gas containing H_2S through a flare stack to combust the dangerous vapors.

Recommendation No. 84: H_2S monitoring and reporting requirements should be included in the RDSGEIS as a mitigation measure and codified in the NYCRR. Operators should be required to follow H_2S detection and handling procedures to protect employees and the public. Initial H_2S testing should be conducted at each drillsite. Subsequent test frequency should be based on the results of initial testing. H_2S levels can increase over time as gas fields age and sour. H_2S requirements should be included in regulation for both drilling and production operations, and should not just be relegated to a drilling permit condition. Additionally, when H_2S is present, nearby neighbors, local authorities, and public facilities should be notified, and provided information on the safety and control measures that the operator will undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

21. Chemical & Waste Tank Secondary Containment

Background: In 2009, HCLLC recommended that NYCRR be revised to include secondary containment for chemicals stored on the well pad or, alternatively, require the use of double-wall tanks. Chemicals, especially corrosive chemicals, can result in storage container leaks and spills to the environment. Best practice for permanent chemical storage is to install secondary containment under the storage container, and ensure the containers are not in contact with soil or standing water.[348] Shale gas drilling and HVHF operations include the use of many chemical tanks and waste handling tanks (e.g. flowback tanks) that warrant secondary containment.

2011 RDSGEIS: NYSDEC responded to public comments and made appropriate revisions to the 2011 RDSGEIS with its requirement for 110% secondary containment for all chemical and waste handling tanks. It also requires secondary containment for chemical and waste transport, mixing and pumping equipment. The 2011 RDSGEIS states:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[349]
>
> *Secondary containment would be required for all fracturing additive containers and additive staging areas. These requirements would be included in supplementary well permit conditions for high-volume hydraulic fracturing.*[350]
>
> *Secondary containment measures may include one or a combination of the following; dikes, liners, pads, curbs, sumps, or other structures or equipment capable of containing the substance. Any such secondary containment would be required to be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area.*[351]
>
> *Secondary containment for flowback tanks is required.*[352]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[353]
>
> *Location of additive containers and* ***transport, mixing and pumping equipment****…within secondary containment…[emphasis added]*[354]

[348] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.

[349] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[350] 2011 NYSDEC, RDSGEIS, Page 7-38.

[351] 2011 NYSDEC, RDSGEIS, Page 7-38.

[352] 2011 NYSDEC, RDSGEIS, Page 7-40.

[353] 2011 NYSDEC, RDSGEIS, Page 1-12.

[354] 2011 NYSDEC, RDSGEIS, Page 7-29.

Recommendation No. 85: Secondary containment requirements for well site chemicals should be applied as a best practice to all oil and gas development and codified in NYCRR, and should not be limited to shale gas and HVHF operations.

NYCRR Proposed Revisions: Proposed regulations codify the requirement for secondary containment for chemical and waste handling tanks, but do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment.

Recommendation No. 86: Consistent with the proposed RDSGEIS mitigation, 6 NYCRR § 750-3.11 and 6 NYCRR § 560.6 should be revised to require lined secondary containment for chemical and waste transport, mixing, and pumping equipment.

Proposed regulations at 6 NYCRR § 750-3.11 provide very specific instructions on how to construct adequate secondary containment, including the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. Regulations also state that the containment structures must have adequate freeboard, be protected from damage, and be able to contain at least 110% of the largest tank volume.

> ***750-3.11 Applications of standards, limitations and other requirements***
>
> *(e) The HVHF SWPPP must, at a minimum, include the HVHF SWPPP General Requirements listed in subparagraph (1) below, Structural Best Management Practices (BMPs), Non-structural BMPs, and Activity-Specific SWPPP Requirements.*
>
> *(v) Secondary Containment - To prevent the discharge of hazardous substances, the owner or operator shall provide, implement, and operate secondary containment measures.* ***Such secondary containment shall be: (a) designed and constructed in accordance with good engineering practices, (b) constructed, coated or lined with materials that are chemically compatible with the environment and the substances to be contained, (c) provide adequate freeboard, (d) protected from heavy vehicle or equipment traffic; and have a volume of at least 110 percent of the largest storage tank within the containment area*** *[emphasis added].*

In contrast, proposed regulations at 6 NYCRR § 560.6 offer substantially less instruction on how to construct adequate secondary containment. They do not mandate the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. They do not require the containment structure have adequate freeboard. Nor do they require that the containment be protected from damage.

> ***§560.6 Well Construction and Operation.***
>
> *(c) Drilling, Hydraulic Fracturing and Flowback.*
>
> *(26) Hydraulic fracturing operations must be conducted as follows:*
>
> *(i) secondary containment for fracturing additive containers and additive staging areas, and flowback tanks is required.* ***Secondary containment measures may include, as deemed appropriate by the department, one or a combination of the following: dikes, liners, pads, impoundments, curbs, sumps or other structures or equipment capable of containing the substance****. Any such secondary containment must be sufficient to contain*

> *110 percent of the total capacity of the single largest container or tank within a common containment area. No more than one hour before initiating any hydraulic fracturing stage, all secondary containment must be visually inspected to ensure all structures and equipment are in place and in proper working order [emphasis added].*

Recommendation No. 87: 6 NYCRR § 560.6 should be revised to include specific secondary containment construction standards that are consistent with 6 NYCRR § 750-3.11.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing: Permit conditions have been developed to require secondary containment. However, the permit conditions merely echo proposed regulations at 6 NYCRR § 560.6. They do not provide additional or supplemental requirements to the NYCRR.

Recommendation No. 88: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing contained in the RDSGEIS to remove requirements that are redundant with NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

22. Fuel Tank Containment

Background: In 2009, HCLLC recommended that the NYCRR be revised to require more stringent oil spill prevention measures for temporary fuel tanks associated with drilling and well stimulation activities, and that NYS' regulations be at least as stringent as federal EPA's Spill Prevention Control and Countermeasures (SPCC) Plan. HCLLC recommended that NYSDEC incorporate existing EPA oil spill prevention standards into the NYCRR. EPA standards require secondary containment if a facility stores 1,320 gallons of fuel or more (30 CFR § 112), including portable, temporary fuel tanks.

In 2009, NYSDEC proposed to exempt drilling rig and HVHF fuel tanks (even those as large as 10,000 gallons) from NYS' petroleum bulk storage regulations and tank registration requirements at 6 NYCRR §§ 612-614, citing the fact that the storage tanks are temporary (non-stationary) as the reason for the exemption. This problem persists in the 2011 RDSGEIS.

HCLCC questioned NYSDEC's rationale for exempting drilling rig and HVHF fuel tanks from NYS' spill prevention regulations, as all other tanks 1,100 gallons and larger must register in NYS, install secondary containment, and undergo inspections at 5- and 10-year intervals.

HCLLC pointed out that a temporary fuel tank poses a greater environmental risk than a stationary fuel tank, because temporary fuel tanks are relocated many times during their operating lives, increasing the potential for tank damage during transit and the likelihood of tank appurtenance leakage.

Large temporary fuel tanks should be subject to the same secondary containment requirements as large stationary fuel tanks in NYS, particularly in situations where temporary fuel tanks are installed in one location for a significant period of time (e.g. a multi-well pad where drilling and completion operations could span several years). Alternatively, where secondary containment is not technically feasible, the use of double-walled or vaulted tanks should be considered for portable fuel tanks.

In January 2011, NYS' consultant, Alpha Geoscience, reviewed HCLLC's recommendation and provided NYSDEC with incorrect guidance on EPA's secondary containment requirements for onshore oil drilling workover and mobile equipment and other fuel storage.[355] Alpha Geoscience advised NYSDEC that EPA's SPCC regulations only addressed stationary fuel tanks greater than 1,320 gallons.

Alpha Geoscience's advice was incorrect because EPA's SPCC rules apply to facilities that have an aggregate fuel or hydrocarbon storage of 1,320 gallons or more at a facility, and secondary containment rules are not limited to stationary tanks.[356]

2011 RDSGEIS: NYSDEC's 2011 proposal for fuel tank secondary containment is confusing and inconsistent. The RDSGEIS both recommends and requires fuel tank secondary containment as a best practice, yet also exempts large fuel tanks used for drilling and HVHF operations.

For example, the 2011 RDSGEIS states that secondary containment will be required for fuel tanks and areas where fuel transfers occur:

[355] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 21.

[356] USEPA, SPCC Guidance for Regional Inspectors Version 1.0, November 28, 2005, Page 2-16.

> ***The Department proposes to require****, via permit condition and/or new regulation, that* ***operators provide secondary containment around all*** *additive staging areas and* ***fueling tanks, manned fluid/fuel transfers and visible piping and appropriate use of troughs, drip pads or drip pans*** *[emphasis added].*[357]

NYSDEC supports its recommendation for fuel tank secondary containment by pointing out that its consultant has identified it as a best management practice:

> *In addition to its regulatory survey, Alpha also reviewed and discussed best management practices directly observed in the northern tier of Pennsylvania and noted that "[t]he reclamation approach and regulations being applied in PA may be an effective analogue going forward in New York."* ***The best management practices referenced by Alpha include…Secondary containment structures around petroleum storage tanks and lined trenches to direct fluids to lined sumps where spills can be recovered without environmental contamination*** *[emphasis added].*[358]

Yet, the 2011 RDSGEIS exempts large fuel tanks from secondary containment by designating drilling rig and HVHF fuel tanks as "temporary":

> *The diesel tank fueling storage associated with the larger rigs described in Chapter 5 may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the length of time required to drill all of the wells on the pad. However, the tank would be removed along with the rig during any drilling hiatus between wells or after all the wells have been drilled. There are no long-term or permanent operations at a drill pad which require an on-site fueling tank.* ***Therefore, the tank is considered non-stationary and is exempt from the Department's petroleum bulk storage regulations and tank registration requirements*** *[emphasis added].*[359]

The 2011 RDSGEIS does not explain why a temporary fuel tank would pose less risk of a spill than a stationary fuel tank.

The 2011 RDSGEIS further confuses the issue by stating that all fuel tanks would be included in secondary containment:

> *The following measures are proposed to be required, via permit condition and/or regulation, to prevent and mitigate spills.* ***For all wells subject to the SGEIS****, supplementary permit conditions for high-volume hydraulic fracturing* ***would include the following requirements with respect to fueling tanks and refilling activities****:*
>
> > *a.* ***Secondary containment consistent with the objectives of SPOTS 10 for all fueling tanks****.*
> >
> > ***The secondary containment system could include one or a combination of the following: dikes, liners, pads, holding ponds, curbs, ditches, sumps, receiving tanks or other equipment capable of containing spilled fuel****. Soil that is used for secondary containment would be of such character that a spill into the soil will be readily recoverable and would result in a minimal amount of soil contamination and*

[357] 2011 NYSDEC, RDSGEIS, Page 1-11.

[358] 2011 NYSDEC, RDSGEIS, Page 8-5.

[359] 2011 NYSDEC, RDSGEIS, Page 7-343.

infiltration. Draft Department Program Policy DER-1730 may be consulted for permeability criteria for dikes and dike construction standards, including capacity of at least 110% of the tank's volume [emphasis added]. [360]

Ultimately, the 2011 RDSGEIS, includes secondary containment requirements for all fuel tanks, in Appendix 10, Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing.

13) ***Secondary containment*** *consistent with the Department's Spill Prevention Operations Technology Series 10, Secondary Containment Systems for Aboveground Storage Tanks,(SPOTS 10)* ***is required for all fueling tanks*** *[emphasis added];*

14) *To the extent practical, fueling tanks must not be placed within 500 feet of a public or private water well, a domestic-supply spring, a reservoir, a perennial or intermittent stream, a storm drain, a wetland, a lake or a pond;*

15) *Fueling tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck, and;*

16) *Troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment.* [361]

While, it is useful that the RDSGEIS finally lands on requiring secondary containment for fuel tanks, there remains a conflict in the text where NYSDEC has proposed to exempt temporary fuel tanks.

Recommendation No. 89: The SGEIS text should be revised to remove the temporary fuel tank exemption from secondary containment described on page 7-34.

Additionally, Appendix 10 permit conditions merely echo proposed regulations at 6 NYCRR § 560.6, and do not provide additional or supplemental requirements to the NYCRR. Therefore, if adopted into regulation, the permit conditions could be streamlined.

Recommendation No. 90: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing to remove requirements that are redundant with the proposed revisions to NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 codify the requirement for fuel tank secondary containment, and set no limit on the size or duration of fuel tank use. These proposed regulations are protective of the environment. The RDSGEIS should be revised to be consistent with the proposed regulations, avoiding future confusion about NYSDEC's intent.

§560.6 Well Construction and Operation.

(b) Site Maintenance.

(1) For any well:

[360] 2011 NYSDEC, RDSGEIS, Page 7-34.

[361] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 3.

*(i) **secondary containment is required for all fueling tanks** [emphasis added];*

(ii) to the extent practical, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond;

(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.

Recommendation No. 91: The SGEIS should be revised to be consistent with the proposed regulations, which require secondary containment for all fuel tanks (6 NYCRR § 560.6) used for shale gas drilling and HVHF operations.

While proposed regulations at 6 NYCRR § 560.6 are useful because they make it clear that secondary containment is required for all fuel tanks, the proposed regulations do not provide specific instruction on how to construct adequate containment.

Recommendation No. 92: 6 NYCRR § 560.6 should be revised to clearly state that all fuel tank secondary containment should be designed and constructed in accordance with good engineering practices, incremental to the minimum federal standards. Good engineering practices include: using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 require a 500' setback for fuel tanks from perennial or intermittent streams, storm drains, wetlands, lakes, and ponds, but only to the "extent practical" with no explanation of what that means in real terms, and under what conditions it would be acceptable to place a fuel tank closer. NYCRR does not include any setbacks from homes or public facilities.

§560.6 Well Construction and Operation.

(b) Site Maintenance.

(1) For any well:

(i) secondary containment is required for all fueling tanks;

*(ii) **to the extent practical**, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond[emphasis added];*

(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.

Recommendation No. 93: Proposed regulations at 6 NYCRR § 560.6 (b)(1)(ii) should be revised to delete the term "to the extent practical," and should include minimum setbacks for fuel tanks from homes and public buildings.

Additionally, the RDSGEIS is problematic because it still references a **draft** NYSDEC Program Policy (DER-17) for construction standards and a September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on secondary containment construction.

Recommendation No. 94: The SGEIS should not rely on a draft[362] NYSDEC Program Policy document (DER-17) for construction standards and an outdated September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on secondary containment construction. Instead, secondary containment requirements for fuel tanks should be codified in the NYCRR and written in a way that is clear, consistent, and enforceable.

The importance of secondary containment for fuel tanks extends beyond shale gas drilling and HVHF operations to all hydrocarbon drilling and HVHF operations.

Recommendation No. 95: Secondary containment requirements for fuel tanks should extend to all hydrocarbon drilling and HVHF operations in NYS. The requirements should not be limited to shale gas drilling and HVHF operations. Therefore, the recommendations made above should be captured in both 6 NYCRR § 560 and 6 NYCRR § 554.

The RDSGEIS does not cite existing EPA spill prevention requirements at 40 CFR § 112, which apply to all fuel tanks, including drilling tanks, at 40 CFR § 112.7(c) and 40 CFR § 112.10(c). EPA's regulations, which were revised in 2002, require secondary containment for fuel tanks at facilities storing 1,320 gallons and more. EPA allows an operator the opportunity to demonstrate under 40 CFR § 112.7(d) that it is impracticable to install secondary containment; however, EPA requires a formal written "impracticability determination." Under this determination, EPA requires periodic tank integrity testing, leak testing of the valves and associated piping, a Part 109 contingency plan, and a written commitment of manpower, equipment, and materials to respond to a spill.

Recommendation No. 96: The SGEIS should cite federal standards (similar to how NYSDEC cited relevant USEPA standards for air quality) and notify the operator that the federal standards must be met. The SGEIS should also clearly explain what additional requirements will be imposed by NYS.

The RDSGEIS should also include: periodic fuel tank inspections to examine structural conditions and document corrosion or damage; the installation of high-liquid-level alarms that sound and display in an immediately recognizable manner; the installation of high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 97: In the NYCRR, NYSDEC should require tank inspections and tank alarm systems.

[362] If NYSDEC decides to refer to policy and guidance documents, those documents at a minimum should be final documents, and NYSDEC should state within those documents that the contents are enforceable.

NYSDEC does not address whether vaulted, double-walled, or self-diking tanks can be used as alternatives to constructing large temporary containment areas. Other oil and gas producing states allow the use of vaulted, self-diking, or double-walled portable tanks to meet the secondary containment requirement in cases where the operator can demonstrate that it is infeasible to install a containment area meeting EPA's 110% of the largest tank volume requirement. NYSDEC could consider allowing these alternative tanks in places where secondary containment is proven to be infeasible.

Vaulted, self-diking, and double-walled portable tanks are equipped with catchments that hold fuel overflow or divert it into an integral secondary containment area. Industry standards for the construction of vaulted, self-diking, and double-walled portable tanks include:

- Underwriters Laboratories' Steel Aboveground Tanks for Flammable and Combustible Liquids (UL 142);
- Appendix J of the American Petroleum Institute's (API) Welded Steel Tanks for Oil Storage (API 650); and
- API's Specification for Shop Welded Tanks for Storage of Production Liquids (API Spec 12F).

Due to the higher potential for damage during relocation and use at multiple sites, it is recommended that inspections be routinely performed on vaulted, self-diking, and double-walled portable tanks. The inspections should identify damage and corrosion using one of the following standards:

- Steel Tank Institute's (STI) Standard for the Inspection of Aboveground Storage Tanks, Third Edition (STI SP00l); or
- API's Tank Inspection, Repair, Alteration, and Reconstruction Standard (API 653).

As an oil spill prevention measure, portable tanks can be equipped with high-liquid-level alarms that sound and display in an immediately recognizable manner; high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 98: NYSDEC should clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed, and codify in the NYCRR the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

23. Corrosion & Erosion Mitigation & Integrity Monitoring Programs

Background: In 2009, HCLLC recommended that NYSDEC require corrosion and erosion mitigation programs. More specifically HCLLC recommended that: equipment be designed to prevent corrosion and erosion; monitoring programs be put into place to identify corrosion and erosion over the well and equipment operating lifetime; and repair and replacement of damaged wells and equipment be completed.

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in oil and gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide (CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves.

HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The 2011 RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require facilities be designed to resist corrosion (e.g. material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment.[363]

As explained in Chapter 20 of this report, the use of recycled HVHF fluid can result in the inoculation of sulfate reducing bacteria in the reservoir, and increased downhole equipment corrosion. And, while NYSDEC indicates that H_2S levels may be initially low in the Marcellus Shale, this may not be the case during the full life-cycle of the well. Nor does the RDSGEIS examine the H_2S of all other low permeability gas reservoirs to know what the H_2S might be for those formations.

Corroded well casings can provide a pathway for gas and well fluids to leak into protected aquifers. Therefore, it is important to install a robust casing system, and it's equally important to ensure that the casing system's integrity is maintained during the well's life.

Corrosion measured on production casing is an important piece of information, because corrosive fluids are known to also degrade the quality of the cement barrier. Corrosive fluids reduce the cement strength and make it more permeable, potentially providing a pathway for hydrocarbons to migrate from zones of higher pressure to lower pressure freshwater zones.

Additionally, the bond between the casing and cement can be compromised over the well's life, creating a "micro-annulus" (a space between the outer pipe wall and cement sheath) that allows vertical migration of hydrocarbons along the outside of the pipe wall. [364,365] Micro-annulus' can be formed during initial

[363] Curran, E., Corrosion Control in Gas Pipelines, Coating Protection Provides a Lifetime of Prevention, Pipeline & Gas Journal, October 2007.

[364] See Ravi, K. (Halliburton), Bosma, M. (Shell) and Gastebled, O. (TNO Building and Construction Research), Safe and Economic Gas Wells through Cement Design for the Life of the Well, Society of Petroleum Engineering Paper No. 75700, 2002. Ravi et. al. concludes: "The extreme operating conditions that occur in gas-storage and gas-producing wells could cause the cement sheath to fail, resulting in fluid migration through the annulus…The sustained casing pressure observed on a number of wells after they have been put on production emphasizes the need to design a cement sheath that will maintain integrity during the life of the well…However, recent experience has shown that after well operations such as completing, pressure testing, injecting, stimulating and producing, the cement sheath could lose its ability to provide zonal isolation. This failure can create a path for formation fluids to enter the annulus, which pressurizes the well and renders the well unsafe to operate…Failure of the cement sheath is most often caused by pressure – or temperature-induced stresses inherent in well operations during the well's economic life."

cementing, or later in the well's life, due to: pipe wall thinning; cement deterioration; the shock of additional well workover activities (perforations, stimulation, drilling); pressure and temperature changes in the well; or by seismic vibrations.

In January 2011, NYS' consultant, Alpha Geoscience, recommended that NYSDEC ignore HCLLC's best practice recommendations for corrosion and erosion, citing Section 6.1.4.2 and 6.1.5.1 of the 2009 DSGEIS. In these sections, another NYS consultant (ICF) estimated the risk of groundwater contamination due to casing failure in a Class II injection well is 1 in 50 million wells.[366] Alpha Geoscience concludes that corrosion and erosion prevention, monitoring, and repair requirements are unnecessary in the NYCRR.

Neither Alpha Geoscience nor ICF provide technical justification for the use of a Class II injection well corrosion risk analysis as a surrogate for a gas well corrosion risk analysis. A Class II injection well risk profile is different than a gas well. Gas wells can continuously produce sources of corrosive gas (CO_2 and H_2S), water, and sediment, that can corrode and erode well casing and surface piping over time.

Neither Alpha Geoscience nor ICF examined:

- The full life cycle of a gas well, and the fact that there is substantial field evidence that well casings do corrode and erode over time;
- The fact that casing inspection logs, caliper logs, temperature surveys, and other wellbore diagnostics are commonly run to examine the well casing condition due to the known problem of gas well corrosion;
- Information on the amount of money spent annually on corrosion inhibitors, pipe coating, and other preventive measures to mitigate corrosion impacts;
- The fact that well service specialists routinely provide well casing patching, repair, and replacement services,[367] because gas well casing failure is a known problem; and,
- The fact that it is best practice to examine the condition of well casing over the well life to verify its integrity, especially before major well work (e.g. additional drilling, stimulation) is completed on an aging well.[368]

Additionally, Alpha Geoscience criticizes HCLLC for citing industry literature on corrosion best practices, stating that HCLLC's inclusion of this material shows industry bias. HCLLC disagrees with Alpha Geoscience's conclusion. Industry has developed most of the technology to address the problem; therefore, it is logical to cite industry literature on this point.

[365] See Stewart, R.B. and Schouten, F.C. (Shell), Gas Invasion and Migration in Cemented Annuli: Causes and Cures, Society of Petroleum Engineering Paper No. 14779, SPE Drilling Engineering, March 1988. Stewart and Schouten conclude: "*Gas migration resulting from casing contraction is a common field problem… Annular gas-migration problems can develop in an old well owing to changes in pressure or thermal conditions in the well.*"

[366] Alpha Geoscience, Review of the dSGEIS and Identification of Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 18.

[367] Storaune, A., Winters, W.J. (BP America Inc.), Versatile Expandables Technology for Casing Repair, Society of Petroleum Engineers, SPE Paper No. 92330-MS, SPE/IADC Drilling Conference, 23-25 February 2005, Amsterdam, Netherlands, 2005, p.1.

[368] Brondel, D., Edwards, R., Hayman, A., Hill, D., Shreekant, M., Semerad, T., Corrosion in the Oil Industry, Oilfield Review, April 1994, p. 9-10.

Experienced engineers know the importance of assessing and implementing programs to mitigate corrosion/erosion risk early in the field/well lifecycle. Corrosion of gas production equipment is a fundamental concern for the oil and gas industry that has been identified for decades.

> ***Failures of equipment handling or producing natural gas occur only in the absence of an adequate corrosion-control program. A successful program is shown to include (1) anticipation of corrosion in design factors of all equipment, (2) detection of corrosion within the system and measurement of its severity for future reference, (3) use of mitigation measures and (4) continual follow-up and adjustment of control techniques.*** *Design factors to be considered are tubing couplings, packers, tubing grade and size, and the number of tubing strings to be set.* ***Future corrosion problems and mitigation work should be recognized at the time the well completion is made so that the best possible design factors can be realized. Corrosion can be detected by gas analysis, water analysis, coupon exposures and caliper surveys. Quantitative data are needed to determine the severity of the problem and to design a suitable program of alleviation of the corrosion.*** *Use of inhibitors and plastic coatings are popular methods for mitigation of corrosion. Both methods have advantages and disadvantages that must be realized and evaluated. Control limits for a mitigation program should be established so that the operator can be certain that he is receiving the desired protection.* ***Gas gathering and process equipment also often suffer from corrosion….***
>
> *It is suggested that an adequate corrosion-control program must include efforts at various levels of company operations. All engineers and supervisors must participate actively in the corrosion-control effort.* ***As a property is being developed, corrosion control should be considered when the equipment to be used is being selected. When development is complete, the operating people must determine the seriousness of their corrosion problems. They must realize that the corrosion attack may change with changes in production characteristics and that absence of corrosion today does not guarantee absence of corrosion tomorrow. When corrosion is detected within an operation, mitigation is in order*** *[emphasis added].*[369]

Because of the known problem of casing corrosion, the National Association of Corrosion Engineers (NACE) developed Recommended Practice RP0186 to mitigate external casing corrosion; this standard applies to the design of cathodic protection for external surfaces of steel well casings, and would be used when soil/subsurface reservoir conditions present a corrosive environment warranting installation of cathodic protection system installation.[370]

NACE International writes:

> *Oil and gas wells represent a large capital investment.* ***It is imperative that corrosion of well casings be controlled to prevent loss of oil and gas, environmental damage, and personnel hazards, and in order to ensure economical depletion of oil and gas reserves necessary*** *[emphasis added].*[371]

[369] Fincher, D.R. (Tidewater Oil Co.), Corrosion in Gas Wells and Gas Gathering Systems, Journal of Petroleum Technology, Volume 13, Number 9, September 1961, Abstract.

[370] NACE International Standard RP0186-2001, Application of Cathodic Protection for External Surfaces of Steel Well Casings.

[371] NACE International, Application of Cathodic Protection for External Surfaces of Steel Well Casings, RP0186-2001, 2001, p.1.

Gas operators stress the importance of corrosion monitoring and control programs. For example, OMV Exploration and Production writes:

> ***Corrosion remains a key issue in petroleum production****. Its continued occurrence has consequences on the safety of people and environment and the integrity of facilities and affects the economy of the oil or gas field. Particularly the presence of severe environments containing corrosive components such as carbon dioxide and hydrogen sulphide poses serious problems.* ***A central element in the design of facilities and the corrosion control is therefore the proper choice of materials which are both economical and provide a satisfactory performance over the entire service life with respect to the given environment. Prior to the production phase reliable corrosion monitoring programmes have to be selected, established, and implemented, as necessary*** *[emphasis added].*[372]

The magnitude and complexity of a corrosion/erosion mitigation program will vary depending on site-specific conditions. The important step is to complete the initial evaluation, assess the site-specific circumstances, and develop an adequate corrosion/erosion mitigation plan. Some mitigation programs are started early, some are applied intermittently, and others are instituted later in the gas production process; in all cases, an engineering assessment prior to gas drilling and production must be completed to determine the optimal plan.

The corrosion engineering textbook, Corrosion Control in Oil and Gas Production, explains the importance of developing a site-specific plan:

> ***The many possible alternatives available today for corrosion management for gas and oil well environments, dictates the need for a thorough evaluation and development of long term plans to assure a safe, economical and effective program****. History has shown that both corrosion inhibition and corrosion resistant alloys (CRAs) have been used successfully in tough environments. The final decision on which method to use is often made on the basis of available capital versus long term operating costs [emphasis added].* [373]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantially improved well casing program, including a three-casing-string design. However, this casing is typically made of carbon steel, and must be protected from corrosion and erosion. Chromium steel and corrosion resistant alloys are commonly installed in corrosive environments; however, these metals are substantially more expensive and are not currently proposed for NYS.

Well casing, once installed and cemented into place, will remain in the well for its entire lifecycle, and is often abandoned in place.[374] Therefore, it is in the operator's best economic interest to ensure that its casing investment is protected from corrosion and erosion.

[372] Oberndorfer, M. (OMV Exploration and Production), Corrosion Control in the Oil and Gas Production-5 Successful Case Histories, CORROSION Conference 2007, March 11-15, 2007, Nashville Tennessee, NACE International, 2007, p.1.

[373] Treseder, R.S., Tuttle, R.N., Corrosion Control in Oil and Gas Production, Chapter 14, Corrosion of Steels in Gas Wells, 1998.

[374] In some circumstances corroded casing will be pulled from a well prior to abandonment, although this process can prove difficult, time consuming, and expensive for fully cemented casing strings.

It would be shortsighted for NYS to require a robust well casing program, and not build in a corrosion and erosion control program. Chemicals, metallurgy, monitoring, and repair techniques are available to the operator to manage corrosion and erosion downhole (in the well) and at its surface facilities (e.g. corrosion inhibitors, cathodic protection systems, coatings).

Tools that can be used to monitor well corrosion include caliper tools and casing inspection logs. A caliper tool is run down the inside of the well casing or tubing to measure the internal diameter and assess metal wall loss. Casing inspection logs use ultrasonic and magnetic-flux technology to estimate metal wall loss. Additionally, temperature surveys can be run to look for gas cooling anomalies in the well, which are an indication of casing holes. [375]

NYSDEC has proposed cement evaluation tools to be run when HVHF wells are initially drilled and completed, which is a best practice. Cement integrity should also be monitored periodically over the well's life if casing corrosion occurs. Casing corrosion is an indicator of potential cement deterioration, as explained above.

Without regulations, the decision to invest in corrosion/erosion mitigation and wellbore integrity monitoring is left to the operator. In some cases, operators postpone mitigation to improve early economics. Deferral strategies can produce unfavorable results in the long-term, but may be attractive to small operators that have limited funds, or to large operators that plan to reap the benefits of early production and sell assets soon thereafter. Operators may not implement, unless required, long-term monitoring when faced with declining production, lower profits and when operating cost cuts are sought.

Corrosion and erosion programs that are instituted early can prolong the life of equipment and well casings, and reduce environmental risk. Delayed attention to corrosion and erosion mitigation can result in increased safety, environmental, and human health risks.

Gas well corrosion and erosion can occur in many ways:

- Oxygen contaminated drilling fluids are injected downhole, and can corrode well casing and drilling equipment;
- Water produced along with gas can corrode well casing, tubing, and downhole equipment;
- Acid stimulation treatments, used alone or in conjunction with hydraulic fracturing, readily attack metal;
- Well casing and surface piping can be eroded by high gas production velocities, especially when laden with sediment, sands, or hydraulic fracturing proppants;
- Corrosive soils can cause external corrosion of carbon steel casing;
- Hydrogen sulfide and carbon dioxide, often present in gas production, can corrode carbon steel; and
- Higher wellbore temperatures, increased velocity, and increased salinity accelerate corrosion rates.

NYCRR Proposed Revisions: NYSDEC has not proposed any new requirements for corrosion or erosion mitigation for the Marcellus, Utica, or other low-permeability reservoirs. There are no requirements for corrosion or erosion mitigation or long-term well integrity monitoring in the existing NYCRR.

[375] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

Recommendation No. 99: Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be included in the SGEIS and codified in the NYCRR. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

24. Well Control & Emergency Response Capability

Background: In 2009, HCLLC recommended that NYSDEC require an operator to have an Emergency Response Plan (ERP) and a well blowout control plan. HCLLC recommended that operators be required to demonstrate that they have access to sufficient personnel and resources to respond to a fire, explosion, blowout, or other industrial accident. Best practices include: developing response and well control plans; verifying there are a sufficient number of trained and qualified personnel to carry out the plans; ensuring operators have access to the necessary response equipment; and testing (drills and exercises) the plan prior to drilling.

In 2009, HCLLC also recommended that NYSDEC examine the capacity of local emergency response teams. Oil and gas industry accidents often require highly specialized response capability and equipment. Operators should be required to supplement local emergency response resources to meet this need.

In January 2011, NYS' consultant, Alpha Geoscience, concluded that NYS well control and emergency response planning requirements are narrowly focused on the Bass Island Trend wells. Alpha Geoscience agreed with HCLLC that new regulations are needed for the formations proposed for development under this SGEIS.[376]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a new section (Section 7.13) on Emergency Response Plans, which is a substantial improvement. Section 7.13 states:

> *7.13 Emergency Response Plan*
>
> *There is always a risk that despite all precautions, non-routine incidents may occur during oil and gas exploration and development activities.* ***An Emergency Response Plan (ERP) describes how the operator of the site will respond in emergency situations which may occur at the site.*** *The procedures outlined in the ERP are intended to provide for the protection of lives, property, and natural resources through appropriate advance planning and the use of company and community assets.* ***The Department proposes to require supplementary permit conditions for high-volume hydraulic fracturing that would include a requirement that the operator provide the Department with an ERP consistent with the SGEIS at least 3 days prior to well spud.*** *The ERP would also indicate that the operator or operator's designated representative will be on site during drilling and/or completion operations including hydraulic fracturing, and such person or personnel would have a current well control certification from an accredited training program that is acceptable to the Department [emphasis added].*
>
> *The ERP, at a minimum, would also include the following elements:*
>
> - *Identity of a knowledgeable and qualified individual with the authority to respond to emergency situations and implement the ERP;*
> - *Site name, type, location (include copy of 7 ½ minute USGS map), and operator information;*
> - *Emergency notification and reporting (including a list of emergency contact numbers for the area in which the well site is located; and appropriate Regional*

[376] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 42.

Minerals' Office), equipment, key personnel, first responders, hospitals, and evacuation plan;

- *Identification and evaluation of potential release, fire and explosion hazards;*
- *Description of release, fire, and explosion prevention procedures and equipment;*
- *Implementation plans for shut down, containment and disposal;*
- *Site training, exercises, drills, and meeting logs; and*
- *Security measures, including signage, lighting, fencing and supervision.*[377]

Appendix 6, Proposed Environmental Assessment Form Addendum, requires an Emergency Response Plan be located at the rig, and that the plan be followed. [378]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 2, requires an ERP be provided 3 days prior to spud and available at the site. Condition No. 2 requires the ERP be developed in a manner consistent with the SGEIS, but it does not reference the Chapter 7.13 minimum requirements.

> *An emergency response plan (ERP) consistent with the SGEIS must be prepared by the well operator and be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit. Further, a copy of the ERP in electronic form must be provided to this office at least 3 days prior to well spud.* [379]

The addition of an Emergency Response requirement to the SGEIS is a substantial improvement. However, it is recommended that NYSDEC include a review, approval, and audit process to ensure that quality plans are developed. NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

As proposed by NYSDEC, the operator is required to submit an ERP three days prior to commencing drilling. This leaves no time for regulators to review and approve the ERP. NYSDEC proposes no process for determining the adequacy of the ERP. There is no assessment of personnel training and qualifications, equipment resources, or local emergency response services.

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems.

Larger, paid fire and emergency services departments, located near existing industrial developments, may have some industrial firefighting capability; however, the level of capability should be assessed by the operator and supplemented. If local emergency response services are relied upon in the ERP, operators should ensure emergency response personnel are trained, qualified, and equipped to respond to oil and gas industrial accidents. Small, local, volunteer fire and emergency services departments will typically not be equipped or qualified to meet this need.

[377] 2011 NYSDEC, RDSGEIS, Page 7-146.

[378] 2011 NYSDEC, RDSGEIS, Appendix 6, Page A6-7.

[379] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 1 of 17.

Recommendation No. 100: NYSDEC should identify an Emergency Response Plan (ERP) review, approval, and audit process to ensure that quality plans are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells.[380] This risk statistic is applicable to Marcellus and other low-permeability gas reservoir drilling that is still in the exploration and appraisal phase in NYS. Blowout rates are less frequent for production wells where more information is known about the reservoir, well control is optimized, and personnel are more experienced in site-specific conditions. For example, a review of production well blowouts in California estimated 1 blowout per 2,500 wells drilled. [381] California's data showed that: 25% of the blowouts affected more than 25 acres; the average blowout lasted 18 hours; and the maximum blowout length was 6 months.

Using the California statistic of 1 blowout per 2,500 production wells drilled (which is more conservative than the exploration well statistic of 7 blowouts per 1,000 exploration wells), and NYS' estimate of 1600 wells per year over 30 years, an incremental likelihood of 19 blowouts is estimated for NYS.[382] Because some of the early wells drilled will be exploration wells, the blowout frequency many be higher in the first few years of shale gas development in NYS and it is plausible that 40[383] or more well blowouts could occur during the next 30 years. Therefore, blowouts are a reasonably foreseeable significant impact, and mitigation is warranted.

Hydrocarbon reservoirs can contain large quantities of gas and formation water, which can be released into the surrounding environment during a well blowout, resulting in significant damage. For example, the Chesapeake Energy 2011 Marcellus well blowout in Bradford County, Pennsylvania spilled thousands of gallons of fracture treatment fluid over "containment walls, through fields, personal property and farms, even where cattle continue[d] to graze."[384]

Methods to control a gas well blowout can require significant water withdrawals – from 500,000 to 6,000,000 gallons per day. Well control experts may also use foam and dry chemicals to respond to a blowout. Controlling a well blowout can create large volumes of waste. Rig-deluge operations create large pools of water that can transport oil, chemicals, fuels, and other materials toward lower elevation drainage areas.

In addition to the Chesapeake Energy 2011 well blowout, another Pennsylvania Marcellus Shale blowout occurred in 2010.[385,386] Also, in 2010, there was a major industrial fire. The 2010 incidents prompted

[380] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[381] Jordan, P.D., and Benson, S. M., Well Blowout Rates in California Oil and Gas District 4- Update and Trends, Summary of Well Blowout Risks for California Oil and Gas District 4, 1991-2005, Table 1

[382] 19 blowouts= (1,600 wells drilled per year)(30 years)(1 blowout per 2500 wells drilled).

[383] 40 blowouts= 1,600 wells drilled per year)(2 years)(7 blowout per 1000 wells drilled)+(1,600 wells drilled per year)(28 years)(1 blowout per 2500 wells drilled).

[384] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

[385] Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

Pennsylvania to realize the need for its own emergency response services, with trained and qualified personnel and adequate equipment available 24 hours per day, 7 days per week. The news reported that it took "16 hours for out-of-state crews to address a June 3 blowout in Clearfield County and 11 hours to extinguish a July 23 fire in Allegheny County. In both cases, well operators had to wait for response crews to fly in from Texas."[387]

In 2010, CUDD Well Control located a new facility in Canton Township, Bradford County, Pennsylvania. Canton Township is located near the southern NYS border. It may be possible for NYS operators to contract with CUDD to provide emergency response services. However, a better alternative may be for NYS to collaborate with a well control specialist to provide more centrally located services dedicated to supporting NYS' proposed drilling activity.

The 2011 RDSGEIS requires operators to develop and implement a blowout preventer (BOP) testing program. However, the SGEIS does not unequivocally require a well control expert be on contract. It is recommended that NYSDEC require operators to have a contract in place for immediate response by a trained and qualified well control contractor. If a contract with a well control expert is not in place when a blowout occurs, contract negotiations can cause detrimental delays.

Well capping is a proven, effective, and rapid method to control a blowout. Well control contractors provide the expertise and equipment for this operation. However, in some limited cases, well capping is not effective, and a relief well may be required. Therefore, it is important for operators to also have prearranged access to a relief well rig, either via a contract with a rig provider or via a memorandum of agreement to provide emergency response assistance with a nearby operator.

Recommendation No. 101: NYSDEC should require a well blowout response plan (either included in the Emergency Response Plan or as a separate plan), a contract retainer with an emergency well control expert, and prearranged access to a relief well rig.

NYCRR Proposed Revisions: NYSDEC has proposed a new regulation at 6 NYCRR § 560.5 requiring an ERP for HVHF wells. This is a substantial improvement; however, this plan should be required for all wells in NYS, not just HVHF wells. Additionally, the NYCRR should more clearly specify the ERP content requirements and include the recommendations listed above.

Recommendation No. 102: The requirement for an Emergency Response Plan should be codified in the NYCRR. It should apply to all wells in NYS, not just HVHF wells. The NYCRR should specify ERP content requirements. These requirements should be consistent with NYSDEC's recommendations listed in Chapter 7.13 of the 2011 RDSGEIS.

[386] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

[387] http://pagasdrilling.com/tag/cudd-well-control/

25. Financial Assurance Amount

Background: In December 15, 2008, scoping comments to NYSDEC, NRDC, and its co-signatories requested the DSGEIS examine whether NYSDEC requires a sufficient financial assurance amount (in the form of a bond or other financial instrument). In its comments on the 2009 DSGEIS, NRDC and its co-signatories, as well as HCLLC, noted that the DSGEIS did not provide an analysis of the current financial assurance requirements, and requested that work be done.

HCLLC recommended that the SGEIS examine financial assurance amounts to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination).

Long horizontal wells are more costly to plug and abandon than vertical wells. Also, surface impacts are increased when high-volume fracture stimulation treatments are employed and multiple wells are drilled from a single well pad. Both of these operations require additional gas treatment and transportation facilities.

In January 2011, NYS' consultant, Alpha Geoscience, advised NYSDEC to ignore financial assurance recommendations, declaring it "out of scope" of the SGEIS, because legislative action would be required at ECL 23-0305(8)(k).[388] HCLCC disagrees. Regardless of whether a legislative change is required, financial assurance improvements for Marcellus Shale gas well drilling should not be disregarded in the RDSGEIS; instead, the SGEIS should recommend to NYS' Legislature the need for legislative action as a mitigating measure.

The 2011 RDSGEIS: The 2011 RDSGEIS still does not include recommendations for increasing the financial assurance amounts for HVHF shale gas operations.

NYCRR Proposed Revisions: There is no proposed revision to the amount of financial security for wells up to 6,000' deep. 6 NYCRR § 551.5. For wells between 2,500' and 6,000' in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000.

For wells drilled more than 6,000' deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6).

In 2003, ICF completed a report for the New York State Energy Research and Development Authority (NYSERDA) on NYS oil and gas wells.[389] ICF's report advised NYS that well plugging and abandonment can range from $5,000 per well to more than $50,000 per well depending on the well depth, well condition, site access, and site condition.[390] ICF's 2003 report recommended that NYS consider increased financial security requirements. NYSDEC's current requirement of only $5,000 financial

[388] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 46.

[389] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003. This report is found at http://esogis.nysm.nysed.gov/esogisdata/downloads/NYSERDA/7012.pdf. The report is listed as a draft, and a final could not be located on the world-wide web.

[390] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page. ES-1.

security per well is clearly insufficient, if ICF determined in 2003 that the cost could be as much as $50,000 per well. Today's cost would likely be higher, almost a decade later.

In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas. The Ohio Code at Title 15, Chapter 1509 requires:

> ***1509.07 Liability insurance coverage.*** ***An owner of any well****, except an exempt Mississippian well or an exempt domestic well,* ***shall obtain liability insurance coverage*** *from a company authorized to do business in this state* ***in an amount of not less than one million dollars bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the drilling, operation, or plugging of all the owner's wells in this state.*** *However,* ***if any well is located within an urbanized area, the owner shall obtain liability insurance coverage in an amount of not less than three million dollars for bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the drilling, operation, or plugging of all of the owner's wells in this state****. The owner shall maintain the coverage until all the owner's wells are plugged and abandoned or are transferred to an owner who has obtained insurance as required under this section and who is not under a notice of material and substantial violation or under a suspension order. The owner shall provide proof of liability insurance coverage to the chief of the division of oil and gas resources management upon request. Upon failure of the owner to provide that proof when requested, the chief may order the suspension of any outstanding permits and operations of the owner until the owner provides proof of the required insurance coverage.[emphasis added]*
>
> *Except as otherwise provided in this section, an owner of any well, before being issued a permit under section 1509.06 of the Revised Code or before operating or producing from a well, shall execute and file with the division of oil and gas resources management a surety bond conditioned on compliance with the restoration requirements of section 1509.072, the plugging requirements of section 1509.12, the permit provisions of section 1509.13 of the Revised Code, and all rules and orders of the chief relating thereto, in an amount set by rule of the chief.*

Recommendation No. 103: NYSDEC's financial assurance requirements should not narrowly focus on the cost for plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be included in the SGEIS as a mitigating measure, even if legislative action is ultimately required. Additionally, improved financial assurance should be codified in the NYCRR during this revision to the extent possible.

By comparison, Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well.[391] Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS.

[391] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

In addition to the bond amount, Fort Worth, Texas also requires the operator to carry multiple insurance policies:

1. *Standard Commercial General Liability Policy of at least $1,000,000 per occurrence. The Standard Commercial General Liability insurance must include: "premises, operations, blowout or explosion, products, completed operations, sudden and accidental pollution, blanket contractual liability, underground resources and equipment hazard damage, broad form property damage, independent contractors' protective liability and personal injury."*
2. *Excess or Umbrella Liability of $5,000,000;*
3. *Environmental Pollution Liability Coverage of at least $5,000,000 "applicable to bodily injury, property damage, including the loss of use of damaged property or of property that has not been physically injured or destroyed; cleanup costs; and defense, including costs and expenses incurred in the investigation, defense or settlement of claims…coverage shall apply to sudden and accidental, as well as gradual pollution conditions resulting from the escape or release of smoke, vapors, fumes, acids, alkalis, toxic chemicals, liquids or gases, waste material or other irritants, contaminants or pollutants."*
4. *Control of Well Policy of at least $5,000,000 per occurrence/combined single limit with a $500,000 sub-limit endorsement for damage to property for which the Operator has care, custody and control; and*
5. *Other insurance required by Texas (e.g. Workers Compensation Insurance, Auto Insurance, and other corporate insurance required to do business in the state of Texas).*[392]

Financial assurance requirements should be increased to address worst-case risk exposure. Risk assessments should include worst-case scenario financial impact models. The risk modeling should be used to set higher financial assurance requirements.

Recommendation No. 104: The financial assurance requirements at 6 NYCRR §§ 551.5 and 551.6 are insufficient to address the risks to NYS and private parties associated with oil and gas development. It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment.

[392] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

26. Seismic Data Collection

Background: In 2009, HCLLC recommended that NYSDEC improve the DSGEIS and establish regulatory requirements for seismic data collection to reduce impacts to the environment and the public. The 2009 DSGEIS addressed naturally occurring seismic events in Chapter 4, but was silent on the impacts from industrial seismic exploration, which is used to locate subsurface gas reservoirs including shale gas targets.

This problem persists in the 2011 RDSGEIS. The 2011 RDSGEIS discusses naturally occurring seismic events, and seismically induced fractures from HVHF operations, but does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys used to target hydrocarbon formations for exploration and appraisal drilling. These seismic surveys are also useful to identify major fault systems to be used in HVHF design and modeling. Improved understanding of the subsurface stratigraphy and fault systems will improved 3D model simulation predictions and can aid engineers in designing HVHF treatments that do not link induced fractures with existing, conductive, natural fault systems that could move HF fluids into protected groundwater resources or water wells.

In January 2011, NYS' consultant, Alpha Geoscience provided a misguided recommendation to NYSDEC to ignore seismic data collection mitigation in the RDSGEIS, as "irrelevant."[393] Because seismic data collection is typically the first step in unexplored areas, to locate and optimize exploration drilling targets, seismic data collection mitigation when used to target Marcellus Shale wells is hardly "irrelevant."

Therefore, it is unclear whether NYSDEC is not familiar with the use of seismic data collection to target hydrocarbon formations for drilling, and the mitigation measures needed because its consultants advised against study of this important mitigation, or whether shale gas operators have told NYSDEC that they don't intend to collect two-dimensional (2D) or three-dimensional (3D) seismic surveys prior to exploring in the Marcellus Shale.

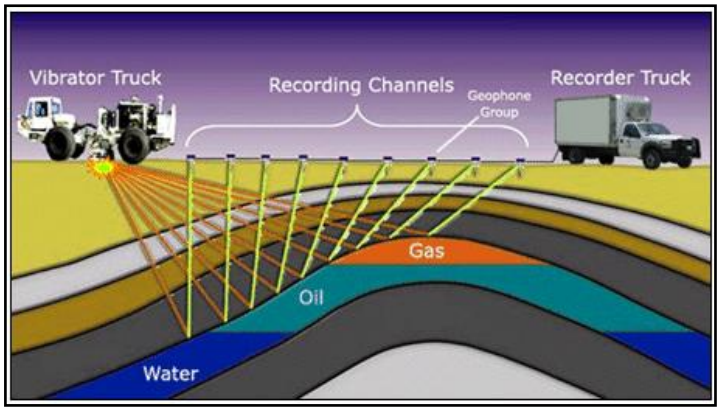
If operators do not intend to collect additional 2D and 3D data, that representation should be stated in the RDSGEIS, and the 2D and 3D data collection should be precluded in NYS. Otherwise, the impacts of this work should be identified and mitigated. This is an important issue to resolve, because seismic surveys can create significant surface impacts and disruptions.

Recommendation No. 105: If 2D or 3D seismic surveys are planned, or are possible in the future, the NYCRR should codify a permitting process for these activities and institute mitigating measures in the SGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas.

Exploration for oil and natural gas typically begins with a geologic examination of the surface structure of the earth, to identify areas where petroleum or gas deposits might exist. Once a geologist/geophysicist has identified an area of potential interest based on surface geologic maps, seismic data collection is typically obtained to identify possible subsurface hydrocarbon traps and structures.

[393] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011.

Seismic exploration equipment is used to send seismic waves into the earth. Seismic waves are generated by a surface positioned source and are measured by a surface positioned receiver. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Collecting seismic data in this manner is called a Reflection Seismic Survey.[394]



A reflection seismic survey involves generating hundreds to tens of thousands of seismic source events, or shots, at various locations in the survey area. The seismic energy generated by each shot is detected and recorded by sensitive receivers ("geophones" on land and "hydrophones" under water) at a variety of distances from the source location. Geophones and hydrophones are connected by long cables to relay the collected information back to a centralized computer. The photo to the left is a geophone and cable system.[395]

For every source event, each geophone generates a seismogram or trace, which is a time series representing the earth movement at the receiver location. A record of all traces for each shot is transmitted to a computer for storage and conversion into a seamless cross-sectional representation of the subsurface for subsequent study and interpretation by a trained geophysicist.

Onland seismic operations involve generation of seismic vibrations by explosive energy sources or by mechanical sources. One type of energy source for seismic exploration is an explosive charge. Small holes ("shot-holes"), typically 4 inches in diameter are drilled into the earth surface, 10-60' deep depending on surface terrain.[396] Although, some drill holes have been drilled to 200'.[397] The photo to the right shows an example of a shot-hole drill unit.

[394] U.S. Geologic Survey, Seismic Data Acquisition.

[395] Geophone and cable photo from http://www.anr.state.vt.us/dec/geo/newbedu.htm, State of Vermont.

[396] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

[397] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

The hole must be drilled into a hard layer of soil that is sufficiently dense to carry the seismic wave.[398] Explosive charges (typically 5-50 pounds each)[399] are lowered into the hole and detonated to create a shock wave (vibration). Some states have limits on the size of charges that can be deployed near environmentally sensitive areas, human inhabitation and near roadways.

Historic use of explosives on the ground surface resulted in large craters and extensive surface damage. Explosive charges are no longer deployed at the surface. Instead, a shot-hole must be drilled and the explosive lowered into the shot-hole at a sufficient depth to prevent surface craters. Shot-holes are filled with cuttings, bentonite and rocks to minimize surface impact.

Mechanical vibrators are an alternative to the use of explosives, and are more commonly used. Mechanical vibrators provide more consistent source strength and repeatability, and they are more reliable in the case of repeat data acquisition programs or for time-lapse studies.

Mechanical vibrators can include: a pad that thumps the surface of the earth ("thumper trucks"), driven by gravity or compressed air; a truck that generates vibrations ("Vibroseis™ Truck"); and compressed air guns.[400] The photo to the right shows a Vibroseis Truck. The Vibroseis method involves a truck equipped with vibrator pads that are lowered to the ground and triggered. Depending on the subsurface target depth and the purpose of the seismic survey, two or more seismic Vibroseis Trucks (vibrating in sync) may be needed.

In cold climates, ice road construction and use of Vibroseis Trucks for seismic data acquisition is the norm. Seismic data is typically secured over the winter months along ice road routes, to reduce footprint and stress to sensitive areas of the tundra environment.

The use of thumper trucks is not considered best practice because it involves dropping a steel slab that weighs about three tons to the ground to create a seismic vibration. Thumper trucks are large, requiring extensive tree and vegetation removal, and leave land scars.

In areas where seismic data is collected in water, the energy source is usually compressed air in an airgun submerged underwater, because explosives can cause adverse impacts to aquatic life.

[398] The Pembina Institute, Seismic Exploration, www.pembina.org.

[399] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

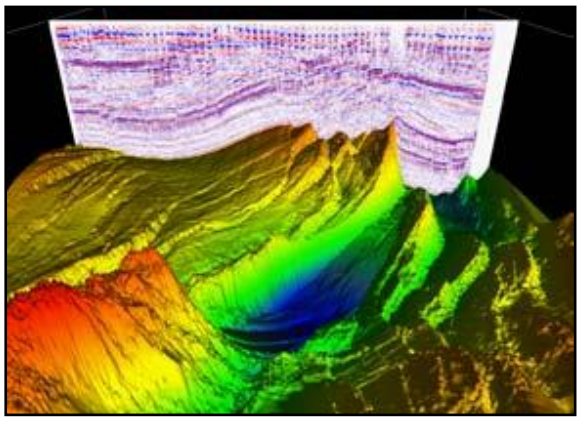
[400] Petroleum Engineering Handbook, Reservoir Engineering and Petrophysics, Volume V(A), Society of Petroleum Engineers, 2007.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight "cutlines" to run seismic equipment (as shown in the photo to the left). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection. The width of each cutline depends on the seismic survey method used, but can be on the order of 20'-50' wide where large seismic equipment units are required. Best practice is to decrease the width of the cutlines to as small as possible using hand carried equipment. More recently companies have been able to reduce cutline width to 6'-10' in certain circumstances.

The spacing between each cutline is dependent on the type of seismic equipment used and depth of examination into the earth. The distance between each cutline is typically 300' apart (shallow reservoir targets) to 3,000' apart (deeper reservoir targets).[401]

Depending on existing development, infrastructure and access in the area planned for onshore seismic exploration, a seismic operator may need to build access roads, set up temporary camps and establish helicopter landings to bring in personnel and equipment. In areas where there are existing roads, housing and airports, surface disturbance can be minimized.

A basic set of seismic data can be obtained by setting a two dimensional array of seismic sources and receivers (2D seismic). Typically 2D seismic requires seismic lines tens of miles apart. Often 2D data is acquired along existing roads or access routes to minimize surface impacts. Along the 2D seismic cutlines shot-points and receivers are evenly spaced to send and receive a signal. This process produces a 2D slice of the subsurface.



If funding is available, operators generally opt to collect three dimensional seismic (3D seismic) images of the subsurface. 3D seismic data acquisition involves a much more intensive data collection effort, using multiple shot lines arranged perpendicular to multiple receiver lines of geophones, with seismic lines spaced several hundred feet apart, rather than miles apart.[402] An example of a map produced from a 3D seismic survey is shown to the left.

Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions. None of these impacts have been analyzed in the NYS RDSGEIS.

There are typically six different crews deployed: (1) access crews, that clear seismic lines, (2) "shooters" that drill the shot-holes and set the explosive charges or run the mechanical vibration equipment to generate seismic waves, (3) "recorders" that set the geophones and measure the seismic reflection, (4) the "pick-up" crews that move the equipment from one location to the next along the seismic lines,

[401] The Pembina Institute, Seismic Exploration, www.pembina.org.

[402] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

(5) logistical support crews that provide housing, food, medical, maintenance and repair, and transportation; and (6) remediation and plugging crews that restore the area and plug shot-holes (if used).

Recommendation No. 106: The increased industrial activity (e.g. economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the SGEIS.

In 2011, HCLLC developed a report for NRDC and Sierra Club describing the types of impacts that occur from 2D and 3D seismic surveys, and made recommendations for best practices and model permit requirements. The recommendations in this report could be considered by NYSDEC in crafting seismic survey requirements for NYCRR.[403]

Recommendation No. 107: Consider the best practices and model permit requirements proposed in Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011, for inclusion as mitigation measures in the SGEIS and improvements in the NYCRR to regulate seismic survey data collection.

[403] Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011.

APPENDIX A

Surface Casing Table

Appendix A - Surface Casing Table

Surface Casing Requirement	2011 RDSGEIS Appendix 8 Casing and Cementing Practices	2011 RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	2011 RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed Permit Conditions and Recommendations in 2011 RDSGEIS	NYCRR Requirements for all Wells, NYCRR Part 554	ADDITIONAL NYCRR Requirements for all HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Setting Depth	75' beyond the deepest fresh water zone encountered or 75' into competent rock (bedrock), whichever is deeper.	100’ below the deepest freshwater zone and at least 100’ into bedrock.	No requirement listed; assume it defaults to the Appendix 8 requirement of 75'.	The Appendix 10 HVHF surface casing setting depth requirement is less stringent than the Appendix 9 requirement; both should be 100'. NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether the setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths.	Surface casing must be run in all wells to extend below the deepest potable fresh water level. Neither the 75' nor the 100' setting depth below the deepest protected water zone is specified in the NYCRR.	No additional requirement.	NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.
Protected water depth estimate and verification	No requirement.	Estimated in drilling application and verified while drilling.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.
Cement Sheath Width	No requirement.	At least 1-1/4".	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

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Amount of Cement in Annulus	Not specified, but it is presumed that the goal is to complete annulus cementing, because the requirements include 25% excess cement; however, the conditions require a reporting of the cement top location, if cement is not returned to the surface, which indicates that NYSDEC could accept a partially cemented annulus.	Entire annulus must be cemented; cement squeeze may be required.	No requirement listed; assume it defaults to Appendix 8 requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus.	There is a requirement to circulate cement to the top of the hole.	No additional requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.
Shallow gas hazards	Surface hole drilling must stop and surface casing must be set and cemented before drilling deeper into hydrocarbon resources.	The likelihood of shallow gas hazards must be estimated in the drilling application and verified while drilling.	No requirement listed; assume it defaults to Appendix 8 requirement.	All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. If a shallow gas hazard is encountered, surface casing should be set and cemented to protect water resources, before drilling deeper into hydrocarbon resources.	No requirement.	No requirement.	If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.
Excess Cement Requirement	25%	50%	No requirement listed; assume it defaults to Appendix 8 requirement of 25%.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume.	No requirement.	No requirement.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

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Cement Type	The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content and contain a gas-block additive.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.
Lost Circulation Control	Required.	Required.	Required.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

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Spacer Fluids	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	Required.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Hole conditioning before cementing	Gas flows must be killed or lost circulation must be controlled and the hole be conditioned before cementing.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	At least every 120', with a minimum of two centralizers. A table of centralizer-hole size combinations is included.	At least every 120'.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

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Casing quality	All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi); used casing may be approved for use, but must be pressure tested before drilling out the casing shoe.	New pipe with minimum internal yield pressure (MIYP) of 1,800 psi, or reconditioned pipe that has been tested internally to a minimum of 2,700 psi, must be used.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.	No requirement.	All casing must be new and conform to the industry standards specified in the permit to drill.	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.	No requirement.	Casing thread compound and its use must conform to the industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

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Drilling Mud	No requirement.	Compressed air or WBM, no SMB or OBM.	Not listed in Appendix 10, but the RDSGEIS text includes a section that states compressed air or WBM should be used on HVHF wells.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells, not just those described in Appendix 9.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.
Cement Setting Time	Compressive strength standard of 500 psi.	No requirement listed; assume it defaults to Appendix 8 requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.
NYSDEC Inspector	No requirement.	Required to be onsite for cementing operations.	No requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation.	No requirement.	No additional requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

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Cement QA/QC - Cement Evaluation Log	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	No requirement listed; assume it defaults to Appendix 8 requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.	No requirement.	No additional requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.
Formation Integrity Test	No requirement.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

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BOP Installation	Confirmation that the surface casing is set and cemented into place, such that the BOP can be secured and effective when drilling deeper into the well.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP.	No requirement.	No requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	Not specified.	Not specified.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the Department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.	No requirement.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

APPENDIX B

Intermediate Casing Table

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Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Waiver Provision to Exclude Use of Intermediate Casing	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.	No requirement.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.
Setting Depth	No requirement.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.
Protected Water Depth Estimate and Verification	No requirement.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.
Amount of Cement in Annulus	No requirement.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.
Excess Cement Requirement	No requirement.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

Appendix B - Intermediate Casing Table

Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	No requirement.	No requirement.	Cement slurry must be prepared to minimize its free water content, in accordance with industry standards and specifications.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used , not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Appendix B - Intermediate Casing Table

Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	No requirement.	No requirement.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers, must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.
Casing quality	No requirement.	No requirement.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Casing thread compound and its use must conform to industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Drilling Mud	No requirement.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.
Cement Setting Time	No requirement.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

Appendix B - Intermediate Casing Table

Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
NYSDEC Inspector	No requirement.	No requirement.	Required to be onsite for cementing operations.	Best practice is to have a state inspector onsite during cementing operations.	No requirement.	No requirement.	Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.
Cement QA/QC - Cement Evaluation Log	No requirement.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	No requirement.	No requirement.	No requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	No additional requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

APPENDIX C

Production Casing Table

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing Design	No requirement.	No requirement.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.	The drilling, casing and completion program adopted for any well shall be such as to prevent the migration of oil, gas or other fluids from one pool or stratum to another.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No additional requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where production casing is set.
Amount of Cement in Annulus	The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.	No additional requirement. Appendix 8 requirement would apply.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice.	If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Excess Cement Requirement	A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	No additional requirement.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.
Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	No additional requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No additional requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement Installation and Pump Rate	The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.	No additional requirement. Appendix 8 requirement would apply.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. The pump and plug installation method is a best practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will be come more difficult with a deviated wellbore, but should be attempted if achievable.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.
Centralizers	Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval.	No additional requirement. Appendix 8 requirement would apply.	At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002)	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.
Casing quality	The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.	No additional requirement. Appendix 8 requirement would apply.	Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited.	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Casing thread compound and its use must conform to industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Cement Setting Time	Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way.	No additional requirement. Appendix 8 requirement would apply.	After the cement is pumped, the operator must wait on cement (WOC): 1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psi, and 2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test.	Operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. This requirement should apply to all NYS wells, not just HVHF wells.
NYSDEC Inspector	No requirement.	No requirement.	This office must be notified _____ hours prior to production casing cementing operations.	Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.	No requirement.	No additional requirement.	Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement QA/QC - Cement Evaluation Log	No requirement.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 “Other Testing and Information” under the heading of “Well Logging and Other Testing” of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009).	The use of a cement evaluation logging tool is best practice.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the production casing.	The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where production casing is set.
Record keeping	No requirement.	No requirement.	A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Additional Casing or Repair	No requirement.	No requirement.	Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.	No requirement.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

Appendix D: List of Acronyms

^{210}Po .....Polonium 210
2D.....two-dimensional
3D.....three-dimensional
API.....American Petroleum Institute
API RP .....American Petroleum Institute Recommended Practice
AQ.....Air Quality
AMD .....Acid mine discharge
ARD .....Acid Rock Drainage
Bcf.....billion cubic feet
BOP.....Blow-out preventer
BTEX .....benzene, toluene, ethylbenzene, and xylenes
BUD .....Beneficial Use Determination
C-NLOPB .....Canada-Newfoundland and Labrador Offshore Petroleum Board
CDA .....Concentrated Development Area
CRI.....Cuttings reinjection technology
CRA .....Corrosion-resistant alloys
CRDPF.....Continuously Regenerating Diesel Particulate Filters
DOI .....United States Department of the Interior
DMM .....Division of Materials Management
EAF.....Environmental Assessment Form
EPA.....Environmental Protection Agency
ERP .....Emergency Response Plan
GHG.....Greenhouse Gases
H2S .....Hydrogen Sulfide
HAP .....Hazardous Air Pollutants
HVHF.....High Volume Hydraulic Fracturing
JPAD.....Jonah-Pinedale Anticline Development Area
LDAR.....Leak Detection and Repair
MACT.....Maximum Achievable Control Technology
MFN.....Microseismic Fracture Network
MMscf.....Million standard cubic feet
MSDS.....Material Safety Data Sheet
MSW.....Municipal solid waste
NAAQS.....National Ambient Air Quality Standards
NACE.....National Association of Corrosion Engineers
NO_X.....Nitrogen Oxide
NORM .....Naturally Occurring Radioactive Material
NRDC .....Natural Resources Defense Council
NYCRR.....New York Code of Rules and Regulations
NYS .....New York State
NYSDEC .....New York State Department of Environmental Conservation
NYSERDA.....New York State Energy Research and Development Authority
NYSDOH.....New York State Department of Health
OBM .....Oil-Based Mud
OSHA.....Occupational Safety and Health Administration
OSPAR.....Oslo-Paris Convention

P&A .....Plug & Abandonment
PA .....Pennsylvania
PADEP.....Pennsylvania Department of Environmental Protection
PLONOR .....Pose Little Or No Risk
$PM_{2.5}$.....Particulate Matter, 2.5 microns or smaller in diameter
POTW .....Publically Owned Treatment Works
ppm .....parts per million
psi.....pounds per square inch
QC/QA .....Quality Control/Quality Assurance
Ra .....Radium
RDSGEIS.....Revised Draft Supplemental Generic Environmental Impact Statement
REC.....Reduced Emission Completions
RP.....Recommended Practice
RCRA.....Resource Conservation and Recovery Act
SBM .....Synthetic-Based Muds
SCR.....Selective Catalytic Reduction
SDWA.....Safe Drinking Water Act
SEQRA .....State Environmental Quality Review Act
SPDES .....State Pollutant Discharge Elimination System
SO_2 .....Sulfur Dioxide
SPCC.....Spill Prevention Control and Countermeasures
SPOTS .....Spill Prevention Operations Technology Series
SRB.....Sulfate-reducing bacteria
STEL.....Short-term exposure limit
STI .....Steel Tank Institute
SWPPP.....Storm Water Pollution Prevention Plan
TDS.....Total Dissolved Solids
TEG.....Triethylene Glycol
TENORM.....Technologically Enhanced Naturally Occurring Radioactive Material
TVD .....True Vertical Depth
USDW.....Underground Sources of Drinking Water
USEPA.....United States Environmental Protection Agency
USGS .....United States Geological Survey
VOC .....Volatile Organic Compound
WBM .....Water-based muds
WOC .....Wait on Concrete

Attachment 2

Tom Myers, Ph. D.

Technical Memorandum

Review and Analysis

Revised Draft

Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

September 2011

January 5, 2011

Prepared for:

Natural Resources Defense Council

New York, New York

Prepared by

Tom Myers, Ph.D.

Hydrologic Consultant

Reno, NV

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INTRODUCTION

This technical memorandum reviews aspects of the *Revised Draft Supplemental Generic Environmental Impact Statement* (RDSGEIS) on the *Oil, Gas and Solution Mining Regulatory Program regarding Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoir*. The New York State Department of Environmental Conservation (NYSDEC) is the lead agency. Throughout this review, I refer to the document as the RDSGEIS. The document was "revised" since its initial publication in 2009. I had prepared a review of the 2009 DSGEIS as Myers (2009).

Appendix A to this technical memorandum is my specific review of Appendix 11 in the RDSGEIS, which has been excerpted from the 2009 DSGEIS without change. Appendix B to this technical memorandum is a paper I wrote which is currently undergoing peer review for a journal; this paper concerns vertical transport of contaminants from the shale to freshwater groundwater.

Since the 2009 DSGEIS, the New York State Energy Research and Development Authority (NYSERDA) contracted with Alpha Geoscience (Alpha) to review the comments I prepared on the 2009 DSGEIS (Myers, 2009). Alpha produced a report titled: *Review of dSGEIS and Identification of Best Technology and Best Practices Recommendations, Tom Myers: December 28, 2009*, prepared by Alpha. The RDSGEIS does not reference, or apparently rely, on this Alpha review in any meaningful way; the bibliography includes a list of 2011 reports by Alpha, but the apparent reference to this review (Alpha 2011) does not include my name. The consultants bibliography includes a subheading with Alpha's report, with "Myers" misspelled, but no apparent use of this reference either. Alpha's reviews prepared for NYSERDA were not available directly on the RDSGEIS web page other than through an obscure link. Appendix C to this technical memorandum is my response to Alpha (2011).

This technical memorandum also reviews the water resources/hydrogeology aspects of the revised regulations, published as *Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560, Subchapter B: Mineral Resources*, referred to throughout as the proposed regulations. This technical memorandum proposes additional regulations throughout the review, and then includes a separate section regarding specific proposed regulations.

The report focuses on three main aspects of the RDSGEIS: (1) hydrogeology, including the hydraulic fracturing (fracking) process, (2) low flow surface water resources, and (3) water-resource-related setbacks. Hydrogeology includes review of the geology, contaminant transport, shale hydrogeology, groundwater quality, and induced seismicity analyses. Low flow

surface water resources include an assessment of the analysis required to determine passby flows and the requirements/restrictions on pumping from aquifers. Consideration of the proposed setbacks includes whether the proposed setback is based on facts or analysis. Specific setbacks considered include those proposed to protect aquifers, wells, springs, and other water-related resources.

The RDSGEIS provides data and analysis almost exclusive to the Marcellus shale, although the regulations purport to govern all low-permeability formations, including the Utica shale (which is mentioned in the RDSGEIS). Developing different low-permeability formations would have different effects than would development of the Marcellus shale, which is the focus of the RDSGEIS. Deeper shale, such as the Utica shale, would generate far more cuttings and use more drilling mud, which present different disposal issues. The amount of water used for fracking could be different, as well. Development of shallower shales would increase the regional hydrogeology impacts and increase the potential vertical contaminant transport and the prevalence of improperly plugged abandoned wells. Additionally, the RDSGEIS focused its analysis from the total amount of surface water withdrawals to wastewater disposal on the wells expected in the Marcellus shale. Additional shale development would vastly increase the impacts beyond those revealed in this RDSGEIS

- *The RDSGEIS and proposed regulations should acknowledge that they apply only to the Marcellus shale.*
- *Additional low-permeability gas plays require additional supplemental GEIS analyses as suggested in RDSGEIS 3.2.1*.

The focus on this review is on development of the Marcellus shale, because except for Chapter 4, the RDSGEIS discussion is limited to the Marcellus shale.

SUMMARY OF FINDINGS

The RDSGEIS only poorly describes the hydrogeology of the Marcellus shale area and of the shale in particular. It does not provide a description of what fracking does to the shale or how it affects the regional hydrogeology. There is no description provided of the geologic formations between the shale and the surface beyond the general stratigraphy and stating that it would be nonconductive to upward flow, a point not supported with data or by the literature. The fault mapping is outdated.

Industry should be required to complete geophysical logging, including conductivity, to determine the lower extent of freshwater (Williams 2010). The definition of freshwater should

be as protective as federal standards, meaning that surface casing should extend to TDS at 10,000 ppm.

The description of fracking is incomplete and incorrect from a hydrogeologic perspective. The contention that out of formation fracking is rare is incorrect based on industry data which has documented fractures as much as 2000 feet above the top of the shale in other states. Also, the contention that fracking pressure dissipates immediately upon cessation of injection is also incorrect, except right at the well. Model simulations show that pressure in the shale remains elevated for more than three months and that that prevents some of the injected fluid from flowing back to the gas well. The injected fluid displaces substantial amounts of formation fluid from the shale into surrounding formations; existing and new fractures allows that fluid to move much further from the shale than expected due simply to the volume injected.

The RDSGEIS dismisses the concept of contaminant transport from the shale to the near-surface aquifers, but there is overwhelming evidence that it is at least possible. Fracking fluids and methane have been found in water wells from fracking in different areas. Simulations indicate it could occur much more in the future. Fracking displaces large quantities of brine, and fractures provide pathways to the surface; fracking may also widen those existing pathways. Areas of natural artesian pressure would allow advection to move fluids and contaminants vertically upward. Mapping areas of artesian pressure, improved regional fault mapping, and site-specific project by project fault mapping should be employed to avoid areas of enhanced vertical transport potential. Long-term multilevel monitoring is also needed to track the future potential of vertical contaminant movement.

NYSDEC proposes setbacks that are not obviously based on observed data. If the setback from fracking in a protected watershed is 4000 feet, the setback from primary or principal aquifers or from public water supply wells should be no less, unless justified by site-specific analyses. Wells located in a 100-year floodplain have a greater than 1 in 4 chance of being flooded in a 30-year project life, therefore wells should be setback further from streams.

The proposed monitoring plans are paltry and insufficient. Simply monitoring existing water wells only shows when that user is affected, it does not protect the aquifer. Water wells are not designed for monitoring. The industry should establish a dedicated groundwater monitoring system downgradient from every well pad, out to at least the distance that a contaminant would travel in five years. Monitoring should continue for at least five years after the cessation of production.

The required passby flows have improved since 2009, as has the method for determining them. In general requiring the Q60 and Q75 monthly flow avoids diversions at all when flows are in the bottom 40 or 25 percent of their normal monthly flow regime, depending on area and

month. Q75 only applies to larger streams (> 50 square mile watershed) during the winter months when flow is generally higher. The RDSGEIS should provide some data to show the estimation methods for ungaged sites is accurate.

HYDROGEOLOGY

This section considers all aspects of the RDSGEIS that concern underground resources, including aspects of geology, shale hydrogeology, contaminant transport, the descriptions of fracking and the potential for fracking-induced seismicity. The toxicity of fracking fluid additives was considered was considered by Dr. Glenn Miller.

General Hydrogeology

The distinction between primary and principal aquifers and other sources (RDSGEIS, p. 2-20) ignores the connections between surface and groundwater. Groundwater from principal aquifers may seep into streams, especially during periods of low flow. Because those aquifers are also used by New Yorkers for water supply, the assertion in the RDSGEIS that "one quarter of New Yorkers … rely on groundwater as a source of potable water" (Id.) understates the number of people who may be affected by groundwater contamination

RDSGEIS Figure 2.1 shows that the north end of the shale parallels a large principal aquifer north of Syracuse. This coincidence deserves explanation at some point in the document.

The RDSGEIS mentions that one quarter of New Yorkers rely on groundwater as a source of potable water (RDSGEIS, p. 2-20). This downplays the connection of groundwater with surface water; many aquifers support stream flow, especially during low flow period, therefore aquifer contamination potentially affects many more people.

Safe yield (RDSGEIS, p. 2-29) is an outdated and flawed concept which should not be repeated in the RDSGEIS. It is flawed because all pumping depletes the aquifer, which contradicts the definition of the phrase (Id.). The preferable concept is sustainable yield which is the amount of water that can be pumped without having significant negative effects on the aquifer and on resources connected to that aquifer; what is significant is a societal question related to the values that depend on the aquifer (Alley et al, 1999).

Presence of Fresh and Salt Water

The federal Safe Drinking Water Act (SDWA) defines an underground source of drinking water (USDW) as "[a]n aquifer or portion of an aquifer that supplies any public water system or that

contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer" (http://water.epa.gov/type/groundwater/uic/glossary.cfm). However, NYSDEC apparently ignores this federal requirement where it specifies that surface casings be extended to 75 feet below the transition from fresh- to saltwater but also specifies 850 feet below ground surface (bgs) as a "practical generalization for the depth to potable water", the point at which near-surface freshwater transitions to saline water, which corresponds to 1000 ppm total dissolved solids (TDS) and 250 mg/l chlorides (RDSGEIS, p. 2-23, 6NYCRR §550(at)). The NYSDEC regulations, by only protecting water to a 1000 ppm cutoff for TDS may not provide protections that for some waters that could apparently meet the definition under the SDWA.

The hydrogeology of southern New York over the Marcellus gas play does suggest that there may be very little water with a TDS higher than the threshold that could actually be developed. Williams (2010) found that freshwater transitions to salt water at about 200 feet bgs in valley areas and about 800 ft bgs in upland areas in three counties in the middle of the Marcellus shale gas play. There was uncertainty around the depth estimates with some freshwater observations at deeper depths. Also the distinction between fresh- and saltwater in his survey of both water and gas wells was based on taste tests rather than any scientific measurement. Williams et al (1998) found similar results in similar geology just across the border in Pennsylvania. Many electric conductivity logs for bedrock water wells in the north Catskill Mountains (Heisig and Knutson 1997) showed that EC would jump from low values representing freshwater to high values representing salt water in a short transition zone or threshold. This suggests that many of the bedrock areas over the Marcellus shale gas play have either high-quality, low-TDS water, or very poor-quality high-TDS water; few wells apparently have water quality near the actual cut-off value. Considering the geology of the area, the zones that have high TDS are also mostly very low hydraulic conductivity zones, so they would not be considered an aquifer because they would not produce sufficient water to support a water supply.

However, the presence of salt water welling up under the alluvial aquifers, which often coincides with fault zones, suggests that salt water does move upward in fractured areas. Water with TDS up to 10,000 ppm may be developable in these higher conductivity fracture zones. In these areas, the NYSDEC regulations may be violating the SDWA requirements to protect USDWs, although the regulations regarding development in primary and principal aquifer may limit drilling in the areas underlain by fractured rock which could have developable high TDS water. Regardless of those aquifer regulations, the threshold for protection should include all areas that qualify as underground sources of water as defined under the Safe Drinking Water Act. These would include waters with TDS up to 10,000 ppm where they exist in an aquifer, and to 1000 ppm or

250 mg/l Cl- in areas underlain by unconductive bedrock. See the separate technical review submitted by Harvey Consulting LLC, for further discussion of the requirements on the SDWA.

- The operator should extend the surface casing to below the 10,000 ppm TDS threshold, unless the operator can show that the formation containing groundwater between 1000 and 10,000 ppm could not produce water in usable quantities. In this case, the operator should extend the surface casing to below the 1000 ppm TDS threshold.

The RDSGEIS does not indicate that the regulations will require the driller to actually locate the transition depth, which would define the depth below which the surface casing would extend a minimum of 75 feet (RDSGEIS, p. 7-50).

- *The regulations should require the operator to complete geophysical logging, including specific conductance logging, prior to casing the well, to determine the actual depth of protected water to which to apply the casing regulations.*

Hydrogeology of the Shale

RDSGEIS Section 4.0 covers Geology, but leaves out most of the important aspects of the Marcellus shale. There is no discussion of hydrogeology of the formations between the targeted shales and the surface, including no discussion of the hydrogeology of the shale itself beyond mention of the permeability. This failure means there is no baseline against which to compare the hydrogeologic changes caused by fracking. There is no hydrogeologic description of the sedimentary layers between the shale and the surface other than very cursory mentions of how it has low permeability. The lack of data on the hydrogeology of formations between the target shale and ground surface is important because NYSDEC relies on geology to "limit or avoid the potential for groundwater contamination" (RDSGEIS, p. 6-2).

Formations that lie between the shale and the surface are generally considered a natural control on fracture propagation and contaminant transport vertically from the shale (RDSGEIS, p. 6-54). RDSGEIS Figure 4-2 does not support the statement that overlying formations will prevent vertical movement of contaminants (RDSGEIS, p. 6-54) because it shows that layers above the Marcellus are primarily sand, limestone, and shale, with no indication of the proportion of each, which controls their conductivity and their propensity to propagate fractures. Most important from the perspective of contaminant transport from the shale to the surface is the prevalence of fractures, both due to faults and otherwise. Faults could be a pathway for vertical contaminant transport (Osborn et al 2011; Myers in review) and could also allow fractures to propagate further from the shale. The RDSGEIS discusses faults only with regard to present day seismicity and the potential for induced seismicity and presents an outdated map (Isachsen and McKendree 1977). A more detailed an integrated analysis of faults and fractures revealed there are many more faults in New York's Appalachian Basin than

previously suspected (Jacobi 2002). The RDSGEIS should include up-to-date information and acknowledge that more faults are probably yet to be found.

There is little information provided in the geology or hydrogeology sections about the make-up of the shale, beyond the amount of organic carbon. The geology chapter does not even mention the presence of pyrite in the Marcellus shale, although there is a brief reference to it for the Utica shale. The sections on "Solids Disposal" mentions pyrite and acid rock drainage of cuttings derived from the Marcellus shale. "As the basal portion of the Marcellus has been reported to contain abundant pyrite (an iron sulfide mineral), there exists the potential that cuttings derived from this interval and placed in reserve pit may oxidize and leach, resulting in an acidic discharge to groundwater, commonly referred to as acid rock drainage (ARD)" (RDSGEIS, p 7-67). ARD will be discussed more below in the Regulations section.

Most industry references state the Marcellus shale is "low-permeability" (RDSGEIS, p. 2), and the proposed regulations apparently rely on this categorization, although not all sources agree with it. Soeder (1988) described Marcellus shale as "surprisingly permeable" and presented data showing the permeability ranges up to 60 microdarcies, as compared to the Huron shale with permeability two orders of magnitude lower. Most reported permeability values are estimated from core samples, but, in a hydrogeologic sense, these estimates do not represent the formation-wide conductivity; point estimates due to scaling effects can be several orders of magnitude less conductive than the formation as a whole due to preferential flow through fractures (Schulze-Makuch et al, 1999), which are prevalent in this area. RDSGEIS Figure 4-2 also does not show the fractures in the overlying formations which prevail throughout New York including in the Marcellus shale zone (Myers in review).

The assertion that the shale requires fracturing "to produce fluids" (Id.) does not prove that the shale above the Marcellus is equally poorly transmissive. Shales above the Marcellus have not apparently trapped gas or fluids for significant time periods, a fact which undercuts the claim they are not transmissive or there is a lack of vertical flow. Fractures that go out-of-formation above the shale connect the shale with the much more transmissive formations above the shale.

The Geology section should also discuss general groundwater flow paths in the formations above the shale; this should include vertical gradients and recharge zones.

- *The RDSGEIS should discuss the hydrogeology of the formations between the targeted shale and ground surface, including data on the hydraulic conductivity of the formations.*

- *The RDSGEIS should also map the groundwater gradients for the formations just above the targeted shale using water level data obtained from geothermal applications and previous deep wells.*
- *The NYSDEC should require the industry to do a seismic survey to locate faults near proposed drilling, within half a mile of the center of the well pad or 1000 feet beyond the projected end of the horizontal wells, whichever is further from the well pad.*
- *The RDSGEIS should include up-to-date fault mapping.*
- *Industry should be required to complete and provide to the NYSDEC geophysical logging of the formations above the targeted shale showing fractures, lithology, and groundwater characteristics.*

Description of Hydraulic Fracturing

RDSGEIS Chapter 5 describes the fracking process, but it does not describe what actually happens to the shale – what does it look like after fracking and what are its properties. It is much more permeable to gas flow, perhaps substantially so, therefore it must also be much more transmissive to water flow. With up to an expected 40,000 horizontal wells over the next 30 years in New York (RDSGEIS, p. 6-6), the properties of the shale, which currently is an aquitard, will change substantially. The RDSGEIS completely fails to address these changes.

Industry designs fracking jobs to keep the fractures in the shale, but data show that the results of the fracking do not always or even often verify the design. The industry rarely monitors or measures the actual extent of fractures (RDSGEIS, p. 5-88), beyond monitoring pressure and injected fluid during fracking. The RDSGEIS references Fisher (2010) as being proof that fractures do not extend into the aquifer zone, but his data actually show that fractures commonly go out of formation (Figure 1). His data show many instances of the top of the fracture zone being more than 1000 feet above the centerline of the shale. As the depth to the centerline of the shale decreases from 8000 to 5000 feet, the vertical fracture growth also appears to decrease from 2000 feet above to 500 feet above the centerline of the shale. The apparent trend to fracture growth above the formation decreasing with decreasing depth may relate to the pressure on the rock or its hardness. The data were not sorted according to formation type and there is no data concerning shale thickness, therefore it is unknown whether fractures extend further in some types of rock or whether out-of-formation fractures are more common with thinner shales.

- *The RDSGEIS should not rely on industry's alleged intent to avoid out-of-formation fracking as a means of preventing the consequences of out-of-formation fracking.*

- *The RDSGEIS and regulations should require geophysical logging and microseismic tests to map how far fractures extend out of formation, and the density of the fractures in different formation. This information should be publically available so that all companies can benefit from experience and so that the public can better understand the process.*

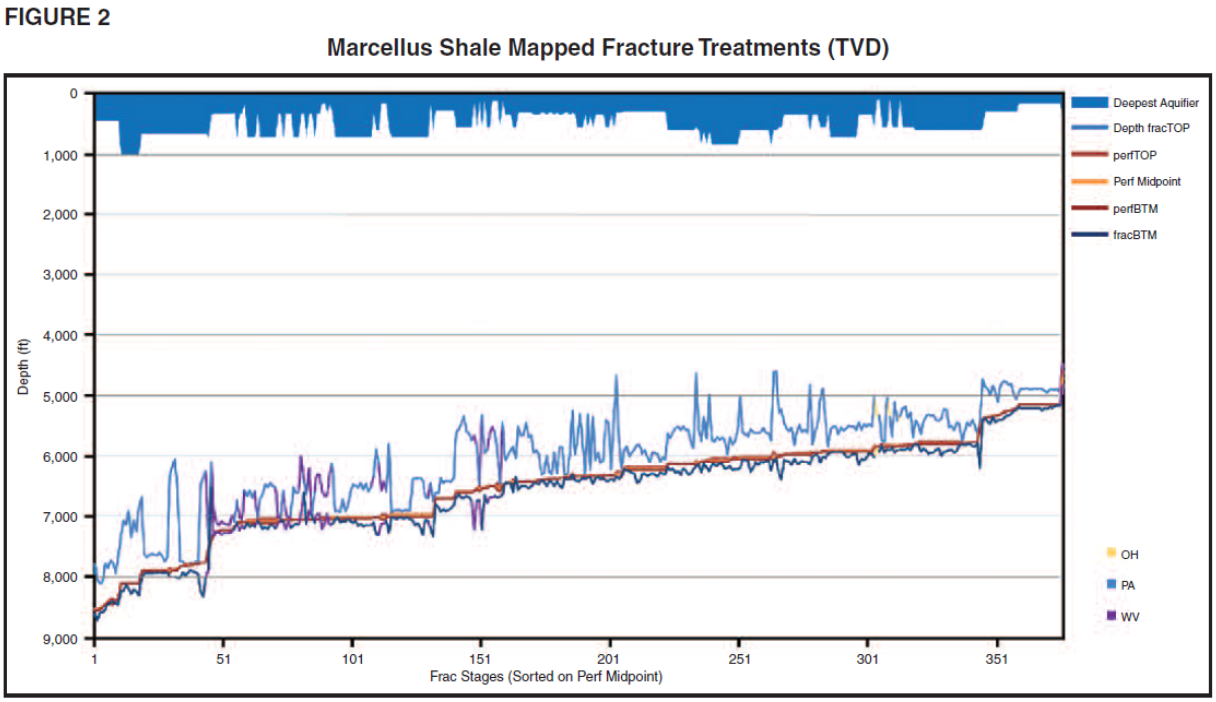

Figure 1: Figure 2 from Fisher (2010) showing the well centerline and a depth to the top of the fracture zone.

It is common practice to compare pressure and flow rate monitoring results from fracking operations to expected values from pre-fracking modeling as a method for evaluating the results of a fracking procedure (RDSGEIS, p. 5-88). Considering that many things affect the pumping flow rate, including pores between the well and the leading extent of the fluid moving away from the well, hydraulically it is difficult to imagine that a significant pressure drop would accompany the leading edge of the fluid reaching surrounding formations. Fracturing into surrounding formations would not bring additional water into the shale, as suggested (Id.), because of the pressures as described elsewhere (Myers in review). The increased porosity in the shale would release substantial brine bound in the shale.

Fracking injects up to 7.2 million gallons of frack fluid into the shale over a well bore up to 4000 ft long – the RDSGEIS suggests these are general upper limits based on fracking in the Marcellus shale in other states. Fractures form or widen as the injection pressure exceeds the normal stress in the shale (RDSGEIS, p. 5-95). The injection would slowly displace any water and gas

that exists in the (extremely small) pore spaces near the well; it would push the natural fluid away from the well bore. Because less than 35% of the injected fluid returns to the well as flowback, a significant proportion of the injected fluid remains underground, presumably occupying pores extending out from the well bore. Assuming a job injects 5 million gallons and there is 20% flowback, approximate average values, and 10% effective porosity resulting from the fracking, the fluid could occupy all pore spaces in a 21-ft diameter cylinder centered on the well. Assuming a more realistic resulting effective porosity of 1%, the fluid could fully occupy the pores out to 62 feet in all directions from the well. Fluids that existed there prior to fracking would be pushed further from the wellbore, likely into surrounding formations. Thus, simple consideration of the volume of fracking fluid injected shows that fluid would move far from the well bore and displace formation fluids even further The calculation does not account for pre-existing preferential flow paths or heterogeneities in the direction that fractures develop, so the fluid would likely move further from the well bore in some directions. The fluid would also follow pathways created by the fractures above the shale, thus fluids could end up much further from the well bore than simple considerations would indicate. .

Shale NG development will affect a large proportion of the shale in New York with fracking fluid, as can be shown by comparing expected fracking fluid volumes with shale volume. The RDSGEIS does not indicate the total area of Marcellus shale within New York. However, Figure 2 in Myers (in review) shows the extent of shale within New York to be 18,680 sq miles. Assuming an average thickness of 100 ft, the total volume is 5.2×10^{13} ft^3. If the expected 40,000 wells are all developed in the Marcellus shale, the injected water volume will approximate 2.1×10^{10} ft^3, which at porosity of 0.01 means that fracking fluid would occupy all of the pores in about 4% of the total Marcellus shale volume[1]. This assumes that none of the fluid reaches surrounding formations, which as shown above is unlikely. It is also unlikely that development will be evenly spaced over the shale as supposed in this calculation, therefore the effect in areas of concentrated development could be underestimated.

Fracking efficiency does not improve if the well spacing is significantly less than 300 m, or about 1000 ft (Krissane and Weisset 2011). It is therefore appropriate to assume that fracking changes the shale over the entire spacing unit, or an area of 660 by 4000 ft. The total area affected by 40,000 wells would be about 3800 square miles, which is about 20% of the total shale area in New York. Based on the extent that injected fluid reaches from the well and the frequency of out-of-formation fracturing (Fisher 2010), it is reasonable to conclude that most fracking affects the shale to its edge. Fracking, based on these assumptions, will significantly change the hydrogeology over at least 20 % of a shale aquitard that extends over 18,680 square miles of New York. Because not all of the total area will be developed, it is a good assumption

[1] This calculation assumes 5,000,000 gallons injected per well and 20% flowback for each of 40,000 wells.

that where development actually occurs, fracking will substantially change the shale hydrogeology.

The statement, that "the volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer" (RDSGEIS, p. 6-53), is also misleading. The total proportion of pores actually filled by injected fluid may be relatively small, but combined with displaced existing brines the injection will affect groundwater over a much larger proportion of the pores. The boundary between salt and freshwater may be displaced or disrupted by advection and dispersion of and by fluids associated with fracking. Additionally the changed properties of the shale over a large area will affect the upward movement of the natural brines. Simple consideration of advection and dispersion shows that the current balance between fresh and salt water could be substantially upset by fracking.

The RDSGEIS also erroneously claims that the pressure applied for injection will dissipate immediately upon cessation of pumping; in the well bore that may be correct, but the fact that pressure exists to push fluid back into the well bore proves that residual pressure remains in the shale and possibly beyond. The statement that "the amount of time that fluids are pumped under pressure into the target formation is orders of magnitude less than the time that would be required for fluids to travel through 1,000 feet of low-permeability rock" (RDSGEIS, p. 5-94, p. 6-53) is technically correct but highly misleading because pressures and conditions for transport from the shale to the near surface will exist long after fracking has finished. Fluids can move away from the well bore at distances from the well bore after the injection ends until the pressure has dissipated; the contrary statement (RDSGEIS, p. 5-94) is wrong in that respect. Myers (in review) describes the modeling of injection and its effect on the pressure distribution in detail. The following is a simpler and more accurate description that should be what appears in the RDSGEIS:

> Hydraulic fracturing involves high pressure injection of fracking fluid into the shale from a horizontal well. This injection fractures the shale and increases the size and connectivity of existing pores. The high pressure creates a pressure gradient from the well to a point in the shale just beyond the expanding volume of injecting fluid where the pressure remains equal to background. If the fluid disperses from the well evenly, the volume will be a cylinder. As injection continues, the radius of the cylinder increases and pressure gradient is from the well to the edge of the cylinder. Offsetting the decreased pressure gradient is an increased effective cross-sectional area for the fluid to cross. The flow away from the well fractures the shale, creating new fractures and increasing the size of the existing fractures. When injection ceases the pressure in the well drops immediately to atmospheric pressure coincident with the well-bottom depth. However, the pressure in the shale begins to drop more slowly, initially equals that caused by injection. Flow away from the well continues as the pressure in the reservoir

created by the HVHF treatment moves fluids towards the well and away from the well both but since there is no more pressure being applied at the well the pressure in the shale near the well begins to drop.

Descriptions in the RDSGEIS (p 5-94) are therefore wrong. Fracking is a transient situation wherein a pressure divide, where the pressure is higher between the well and the end of the fluid, sets up with some fluid movement toward the well and some away from the bore continues. The modeling (Myers in review) shows that this requires about 90 days to effectively dissipate. This counters several statements in the RDSGEIS implying that all fracturing and flow from the well bore ceases at the end of fracking, in about five days.

The claim that the flow direction away from the wellbore would be reversed during flowback (RDSGEIS, p. 6-54) also cannot be correct if only 10 to 30% of the injected fluid actually returns to the well. Some must continue to flow away from, or at least not toward, the well.

NYSDEC makes an unreasonable assumption regarding the flow around the shale after fracking, regarding a discussion of the period between fracking operations if refracking would occur. "It is important to note, however, that between fracturing operations, while the well is producing, flow direction is towards the fracture zone and the wellbore" (RDSGEIS, p. 5-99). Because the goal is to attract gas from the shale, any such low pressure would likely affect just the fracked shale, not formations away from the shale in which fluids would flow according to the background hydraulic gradient. That a small amount of formation water may be produced with time indicates that water from only a small portion of the shale near the well flows toward the well. If the natural gradient in formations above the shale has a vertical component, there will be upward advection of water and contaminants away from the shale.

- *Measurements of the water pressure profile should be made in each well prior to fracking, as it is drilled and before it is cased. This could be a part of the geophysical logging process*.

NYSDEC assumes that it will be rare for a well to be refracked, that is, to repeat the fracking operation years after initially completing it, inappropriately relying on "Marcellus operators'" assurances without reference to a source (RDSGEIS, p. 5-98).

Contaminant Transport from the Shale

The RDSGEIS completely dismisses the concept of vertical contaminant migration from the shale to fresh-water aquifers. Statements suggesting that the only way for the public to be exposed to fracking fluid would be through an accident or spill (RDSGEIS, 5-74) reflect the

dismissal of the potential long-term transport from the shale. This section reviews the evidence and potential for contaminant transport from the shale.

Claiming that regulatory officials from 15 states have "testified that groundwater contamination as a result of the hydraulic fracturing process … has not occurred" (RDSGEIS, p. 6-41 & 6-52) is misleading because they have simply never looked for contamination beyond reports from water well owners. There are no monitoring well networks designed to monitor contaminant transport upward from the fracked shale. The upward transport could also take years, decades, or centuries, not just the few days considered in the RDSGEIS. They are wrong to suggest there is no evidence for such transport.

Two reports have documented or suggested the movement of fracking fluid from the target formation to water wells (EPA 1987; Thyne 2008) linked to fracking in wells. Thyne (2008) had found bromide in wells 100s of feet above the fracked zone. The EPA (1987) documented fracking fluid moving into a 416-foot deep water well in West Virginia; the gas well was less than 1000 feet horizontally from the water well, but the report does not indicate the gas-bearing formation. There is also recent evidence of fracking fluid reaching several domestic drinking water wells near Pavillon, WY from a deep source in a sedimentary sandstone and shale formation Diquilio et al 2011). Deep monitoring wells (depth not specified) have detected synthetic organic compounds including glycols, alcohols, and 2-butoxyethanol, BTEX (including benzene at 50 times the MCL), phenols, trimethylbenzenes, and DRO. Dissolved methane was found at near-saturation levels with an isotopic signature similar to production gas. The EPA identified three pathways for fluid movement. One was nearby wellbores. The second was fluid movement from low permeability sandstone into more conductive sandstone nearby. Third was out-of-formation fractures forcing fracking fluid into overlying formations. NYSDEC should consider this example as a cautionary tale of the potential for vertical movement of fracking fluid to near-surface aquifers.

Methane contamination has been observed to occur in many areas near fracking operations. The RDSGEIS acknowledges that gas migration occurs (RDSGEIS, p. 6-42), but suggests it is limited to well construction problems. This assumption ignores the studies which link the source to much deeper formations (Osborn et al 2011, Thyne 2008). Myers (in review) and Osborn et al (2011) indicate that gas transport could indicate pathways which could also be longer-term fluid pathways; if there is a pathway for gas, there is also a pathway for water.

The RDSGEIS dismisses diffusion of chemicals from the shale to the surface because this would dilute their concentrations; this is correct, but diffusion is only a minor process in the movement of chemicals to the surface and is the wrong process to analyze for consideration of

whether vertical transport could occur. Contaminants move by advection, dispersion, and diffusion, with the later being a minor component. Advection would be the most likely transport process (Myers in review). Upward movement of chemicals could occur by advection wherever there is an upward vertical component to the hydraulic gradient; fractures and faults would enhance that flow. Myers (in review) simulated transport through the bulk media as requiring from 100s to 1000s of years, depending on hydraulic properties and gradient; fractures substantially decreased that simulated time.

The RDSGEIS relies on an analysis by ICF (2009), included in the RDSGEIS as Appendix 11, for its dismissal of potential vertical contaminant transport. Dismissing the potential for such transport based on the gradient occurring just for the time of fracking simply illustrates a lack of understanding of the process and associated groundwater and contaminant flow. ICF (2009) had been part of the 2009 version of the DSGEIS. Appendix A of this technical memorandum reviews ICF (2009) again in detail and Appendix B presents a copy of a journal article (Myers in review), which analyzes in detail the potential for transport from the shale to the surface.

The RDSGEIS should reconsider some of its assumptions and implement several regulatory changes, as specified here:

- *ICF (2009) should be removed in its entirety and substituted with an analysis that at least acknowledges the potential risk for long-term contaminant transport from the shale to the surface. All citations to and conclusions based on ICF (2009) should also be removed from the RDSGEIS.*
- *The RDSGEIS should include the foregoing recommendations concerning hydrogeology, and regulations should be promulgated specifically requiring the delineation of properties of the geologic formations above the shale, the locations of fractures, and mapping of the hydraulic gradients near the proposed drillsites.*
- *The RDSGEIS and regulations should require driller to implement a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport, as described below in the section concerning groundwater monitoring.*

Other Pathways for Groundwater Contamination

Section 2.4.5 incorrectly claims that "[i]mproperly constructed water wells can allow for easy transport of contaminants to the well…" (RDSGEIS, p. 2-22). Transport "to the well" depends on flowpaths and gradients near the well which would only marginally be affected by well construction. Improper water well construction does allow transport of contaminants along the casing which could allow contaminants to move among aquifers, once the contaminants reach

the well. Improperly constructed wells can allow contaminants from aquifer layers which were not intended to be screened to transport to the producing layers.

Flowback and produced water are important potential contaminants, primarily in the potential for blowouts or spills just after fracking and in the potential for leaks from the well bore. Estimates are that from 9 to 35% of the injected fracking fluid, expected to vary from 2.4 to 7.8 million gallons per well, would return as flowback (RDSGEIS, p. 5-99). This is a total flowback of 216,000 to 2.7 million gallons per well (Id.). Estimates also indicate that up 60 percent of the flowback would return within the first four days after fracking ceases (RDSGEIS, p. 5-100). The upper estimate based on these ranges is that 60 percent of 2.7 million gallons, or 1.62 million gallons of flowback will occur within four days of the cessation of fracking. Modeling in Myers (in review) confirms both the relative proportion of injected fluid that becomes flowback and the rapid rate.

Flowback is a mixture of returning fracking fluid and formation fluid, but the limited chemistry data presented in the RDSGEIS suffers from being a single sample per well (RDSGEIS, p. 5-105). The RDSGEIS states that some of the data was provided by the Marcellus Shale Coalition, an industry group, but without reference or actually providing the data; it is not possible for the reader to assess or draw independent conclusions that might differ from the statements in the RDSGEIS. The available data does not apparently allow an assessment of the proportion of shale to injected water. For example, samples with very high salt content probably consist more of shale brine than fracking fluid. RDSGEIS Table 5.10 demonstrates, by its illustration of poor water quality, that the water must be contained. The minimum, median, and maximum for TDS, at 1530, 63,800, and 337,000 mg/l, respectively, suggests the proportions vary widely but that more than half of them are saltier than ocean water. The range in chemicals such as benzene, at 15.7, 479.5, and 1950 ug/l, shows that some flowback could be extremely toxic; the NY MCL for benzene is 5 ug/l, thus most of the samples above detect exceed the standard for this contaminant. Because of the toxic chemistry of flowback water, much more data is necessary, as specified here:

- *The RDSGEIS should present temporal flowback data from specific wells, in tabular or graphical form.*
- *The RDSGEIS should present an appendix with raw data provided by the Marcellus Shale Coalition or link to the data on the internet*.
- *Table 5.10 could be made more understandable by including the detect and MCL levels.*

The RDSGEIS promises that flowback would be contained in “water-tight tanks” for onsite handling (Id.), but the document does not discuss the sizing of the tanks. The proposed regulations address flowback and requirements for capturing it at many points (6 NYCRR §560),

but also fails to specify a size. For example, the operator must include " the number and total capacity of receiving tanks for flowback water" (6 NYCRR § 560.3(a)(12)), and must have secondary containment, "as deemed appropriate by the department"…"sufficient to contain 110 percent of the total capacity of the single largest container or tank within a common containment area" (6 NYCRR § 560.6(x)(26)(i)). Because there are no specifications for the size of the "single largest container", the required secondary containment sizing is not useful.

- *The RDSGEIS and proposed regulations must specify the necessary total capacity for tanks to contain flowback. The required capacity must reasonably exceed the expected flowback as discussed above. It must be able to capture within four days, 60 percent of the 35 percent of the maximum amount of fluid to be injected for fracking.*

RDSGEIS Chapter 5 lists many chemicals that could be used in fracking fluid, but does not list any properties of these chemicals which could affect their flow through soils or through groundwater. The RDSGEIS does not provide data regarding whether and how much they will be attenuated. However, the RDSGEIS inappropriately relies on attenuation (p. 6-53) to mitigate against the potential for long-distance transport.

- *The RDSGEIS should either provide data concerning the transport properties of the various chemicals or not rely on attenuation as a means of mitigating the transport which could results from spills and leaks.*

Groundwater Quality Monitoring

The previous sections of this report have highlighted the poor water quality of fluids associated with fracking operations – the fracking fluid itself and the produced shale-bed water – and the various pathways for aquifers to be contaminated. Small quantities of either of these fluids can significantly pollute groundwater and surface water. The RDSGEIS provides some setbacks in an attempt to protect various receptors – wells, aquifers, or streams – and the adequacy of these is discussed below. With the potential for spills and leaks from multiple sources associated with these operations, the requirements for groundwater quality monitoring in the RDSGEIS and the regulations is paltry and insufficient, as described here.

The proposed monitoring consists only of testing existing private water wells within 1000 ft of the drill site, or to 2000 ft if none are located within 1000 ft (RDSGEIS, p. 1-10, 7-44). While this is necessary for the protection of the well owner, it is insufficient for the long-term protection of the aquifer. Domestic wells have not been designed to function as water quality monitoring wells which causes many problems in sampling and interpreting the data. Thyne explains clearly why domestic wells are poor monitoring wells:

> First, the number of domestic well sample points is far exceeded by the potential point sources (gas wells). Domestic wells are much less than ideal for sampling purposes. Domestic wells are not placed to determine sources of contamination in groundwater. They are not evenly spaced around gas wells or within close enough proximity to determine the presence of chemicals associated with methane that degrade rapidly. Domestic wells are generally screened over large intervals making vertical spatial resolution for samples difficult nor are the wells are not constructed to facilitate measurement of water table elevation or downhole sampling. This forces sampling to occur at the surface after pumping raising the possibility of sampling artifacts. In addition, since domestic wells are the sole source of drinking water for individual properties, it is difficult to arrange access to take samples due to privacy issues, and the County may bear potential liability for damage during sampling and interruption of water supply. (Thyne 2008, p 10-11)

A monitoring well system should be designed so that a contaminant plume will neither pass horizontally between the monitoring wells nor above or below the screened interval. The best way to be certain of intercepting a contaminant passing a point in an aquifer is to span the entire aquifer with well screen. A long screen may increase the chances of detecting the presence of a potential contaminant which may indicate the site being monitored has developed a leak, but will dilute the concentration by mixing contaminated water with cleaner water. A sample extracted from such a well will be a conglomerate of the chemistry of the entire screen thickness; if the screen spans multiple lithologies, the water within the well bore will not be representative of any lithology (Shosky, 1987). It can only be effective only for substances which do NOT naturally exist in the region of the aquifer. Monitoring with long screens is good only for presence/absence determinations.

Concentrations vary throughout an aquifer, both vertically and horizontally. The concentration determined from any well will represent an average over the entire screen length. Therefore, to monitor trends in concentration, screens should span representative vertical sections

The spatial layout of the monitoring well system should be based on the conceptual flow and transport model for flow from the gas well through the aquifer, which includes flow pathways and possible contaminant dispersion. Monitoring wells should be placed as close to the expected flow path as possible, where the concentration will be highest. However, because of uncertainty in the prediction of the flow path, monitoring wells should also be spaced laterally away from the expected flow path. These lateral wells should detect lower concentrations than the one in the predicted flow path. If the lateral wells actually have higher concentration, the predicted flow path may be incorrect and monitoring wells should be added further from the predicted flow path to improve the understanding of the flow and movement of the contaminant plume.

Monitoring wells or piezometers should be placed close to the potential source for early detection, but also at a distance from the source to increase the chances that they will intercept the contaminant and to assess the rate of contaminant movement. If many wells detect the contaminant, the concentration variation would indicate the degree of dispersion. Denser well networks will have a better chance of detecting the contaminant and providing accurate description of it dispersal.

Considering the above fundamentals of a monitoring system, the following recommendations, in addition to sampling the existing private wells, should be added to the RDSGEIS and partly replace proposed regulations in 6 NYCCR §560.5(d)

- *The operator should prepare a conceptual flow path model for groundwater and contaminant transport from the drill pad to and through nearby aquifers.*
- *As part of the conceptual model, the operator should estimate the distance that a contaminant would travel from the well pad in various time periods, including one month, six months, one year, and five years.*
- *Dedicated groundwater monitoring wells should be reasonably located along and perpendicular to the projected flow path out to the five-year travel distance. At a minimum, there should be a transect of monitoring wells/piezometers at the one-month travel distance from the well and halfway between the well and important receptors, meaning wells or discharge points such as springs or streams.*
- *Monitor wells should span the surface aquifer and piezometers should have multiport sampling capabilities for twenty foot intervals at the top of the saturated zone and every 100 feet to the bottom of the freshwater zone. This will help establish vertical concentration and hydraulic gradients.*
- *The monitoring system should be established to establish baseline data including seasonal variability for at least one year prior to drilling and fracking.*

Monitoring transport from the deep shale is more difficult because a substantial flux of contaminants could be released from most anywhere in the fractured shale as a result of oil and gas development. Time intervals for transport could be more than 100 years, but fractures could decrease the time frame to as short a time as a few years. Fracture zones therefore could be monitored, but if they are known the industry should avoid fracking near them, both to avoid vertical transport and induced seismicity. It is therefore reasonable to require a dedicated monitoring well in the middle of each well pad wherever there is an upward flow gradient.

- *Industry should establish a multiport piezometer system from the shale to the bottom of the freshwater zone in the center of all well pads.*

- *The industry should provide the funding to maintain the piezometers system for at least 100 years beyond the end of gas production, to account for the long potential travel times.*

WATER RESOURCES

This section concerns primarily the controls on making water withdrawals for fracking. The section focuses on surface water diversions but also considers diversions from aquifers.

The RDSGEIS notes correctly that without proper controls, the withdrawals of water from streams and aquifers to use in fracking could have significant ecologic and hydrologic impacts (RDSGEIS, p. 6-2). The "natural flow paradigm" is a good description of the interdependencies of the stream ecology with all of the hydrologic regimes (RDSGEIS, p. 6-4). The description of the depletion to an aquifer and the interconnection of aquifers with surface water (RDSGEIS, p. 6-5) is also good. Treating the withdrawals as consumptively lost to the system (RDSGEIS, p. 6-9) is appropriate because in essence, with recycling of flowback, the water will not return to the system. These are acknowledgements which should lead to good regulation of withdrawals, if properly considered in the rulemaking.

The discussion and comparison of the withdrawals for fracking with statewide water uses (Withdrawals for High-Volume Hydraulic Fracturing, RDSGEIS, p 6-9 thru 6-13) are scientifically unsupported and irrelevant;. The potential impacts of withdrawals are a matter of scale and depend on their size, the size of the stream, and antecedent moisture conditions.

Much of the regulation of withdrawals from streams focuses on passby flows. The RDSGEIS defines a passby flow as "a prescribed quantity of flow that must be allowed to pass an intake when withdrawal is occurring" (RDSGEIS, p 2-30) which also specifies a low flow condition "during which no water can be withdrawn" (Id.). Specific definitions will be discussed below, but in reality the lower specified values can allow significant damage to occur to streams, especially smaller ones. If the required passby flow is small compared to the average, meaning it has a long return interval, it will only rarely restrict water withdrawals. If flows on the river can be reduced to a low passby flow, then diversions can reduce the flow to low, long return interval rates much more frequently; this is tantamount to imposing low-frequency, high-damaging, drought on the streams much more frequently.

The Delaware River Basin Commission (DRBC) does not have a specific passby flow requirement and usually uses the 7Q10 flow, the seven-day low flow with a ten-year return interval, for water resources evaluation (RDSGEIS, p. 7-13). The RDSGEIS indicates this is not protective (Id.) and as described in the previous paragraph, it would allow the 10-year low flow to manifest

much more frequently. The Susquehanna River Basin Commission (SRBC) regulations are more complicated, but generally use the 7Q10 or from 15 to 25 percent of the average daily flow (RDSGEIS, p 7-15, 16). Neither is protective and the NYSDEC proposes to use the natural flow regime method (NFRM) method for all regions (RDSGEIS, p 7-16).

The RDSGEIS expresses the intent to use the NFRM only in permit conditions, however, as the document acknowledges that guidance has not yet been completed (RDSGEIS, p. 7-3). As authority, the RDSGEIS cites 6 NYCRR § 703.2, which states that "[n]o alteration that will impair the waters for their best usages" will be allowed. "For the purpose of this revised draft SGEIS only, the Department proposes to employ the NFRM via permit conditions as a protection measure pending completion of guidance." (Id.). NYSDEC also indicates that the requirement could be "imposed via permit condition and/or regulation" (RDSGEIS, p. 7-22).

- *NYSDEC must include the requirement for using the NFRM in the regulations if it is to be consistently enforceable; the proposed regulations do not currently require use of the NFRM to establish the requisite passby flow in a stream.*

The NFRM attempts to protect the distinctive flow patterns for each stream, including the "variable magnitude, duration, timing, and rate of change of flow rates and water levels" (RDSGEIS, p 7-18). The RDSGEIS proposes to use the "Q75 and/or Q60 monthly exceedence values for establishing passby flows" (Id.). An Qx exceedence value is the flow rate which is exceeded x percent of the time. Another way of considering the Q75 and Q60 exceedance values is that the passby flow would be greater than the flow which the stream exceeds 25 or 40 percent of the time. This is much higher than a 7Q10 flow. However, in a small stream, diversions could change a flow regime from wet (higher than average) to significantly below average.

NYSDEC appears to intend that if the watershed exceeds 50 square miles, the passby flow will be Q75 for the winter/spring months of October through June and Q60 for the summer months of July through September, whereas for smaller watersheds (Area<50 sq miles), the Q60 value applies all year (RDSGEIS, p 7-19). NYSDEC at least recognizes that small streams need more protection and that low flows can be more critical during the summer when temperatures are higher. This means that at least 40 percent of the time, withdrawals will not be allowed. For another short time period (up to the time for which the actual streamflow and the required passby flow is less than the preferred withdrawal rate), withdrawals will be limited to prevent the streamflow from being reduced to below the passby flow.

The RDSGEIS does not discuss how the recommended passby flows were chosen, in terms of habitat protected. There is an implication that Q60 and/or Q75 mean the same amount of

habitat would be protected; this may simply be incorrect because streams are not created equal. The NYSDEC should apply a second filter and actually require a determination of the habitat at Q60 and limit the change in habitat. This is one advantage of the Susquehanna River Basin Commission method (RDSGEIS, p 7-15, -16).

The flow estimation method assumes a linear relation between baseflow and drainage area (RDSGEIS, p 7-19). The assumption is that streamflow increases consistently in a downstream direction in proportion to the contributing drainage area. Because it is essential to the method, the RDSGEIS should present data to justify their assumptions. Analyzing streams with two or more gages, the Qx flow at one would be calculated according to the area proportionality relationship with the other gage; the RDSGEIS should present this type of verification to prove the method is suitable.

On streams without gages, the RDSGEIS indicates that NYSDEC will use factors developed from regression equations based on their location in New York (RDSGEIS, Fig 7.1, Table 7.2). The table provides coefficients in cfs/sq mi for the passby flow for the different geographic zone by month. Presumably, they are based on basin areas as discussed above, with different requirements for greater than and less than 50 sq miles. The RDSGEIS should compare values determined with Table 7.2 with the actual value determined for gaged streams to verify the table. Statements such as "[t]he passby flow requirement … would fully mitigate any significant adverse impact from water withdrawals" (RDSGEIS, p 7-22) are unsubstantiated and unjustified.

The passby flow requirements effectively ignore the potential cumulative impacts, irrespective of the following sentence: "The application of the NFRM to all water withdrawals to support the subject hydraulic fracturing operations would comprehensively address cumulative impacts on stream flows because it will ensure a specified minimum passby flow, regardless of the number of water withdrawals taking place at one time" (RDSGEIS, p. 7-25). The RDSGEIS continues by indicating that "significant adverse cumulative impacts would be addressed by the NFRM … because each operator … would be required, via permit condition and/or regulation, to estimate or report the maximum withdrawal rate and measure the actual passby flow for any period of withdrawal" (RDSGEIS, p. 7-25, -26). The RDSGEIS analysis of the prevention of cumulative flow impacts appears limited to these statements. Clearly, several concurrent withdrawals along a stream reach could cumulatively decrease the flow at the more downstream sites to less than the passby flow, if the timing of withdrawals is not controlled and if there are not adequate measurements ongoing at the site which compare the actual flow to the required passby flow. Short of establishing a gaging station with flow/stage relationship, it is difficult to measure flows frequently enough to monitor short-term flow changes, therefore it is unlikely that an operator would be able to react sufficiently to preserve the passby flow.

The following are recommendations for improving the passby flow requirement to be used by NYSDEC

- *The program must be codified into regulations.*
- *The methods for estimating passby flows at ungaged sites must be verified as to their accuracy.*
- *NYSDEC should coordinate operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.*
- *The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.*
- *Passby flows should be maintained with consideration to the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.*

NYSDEC recognizes that groundwater pumping could deplete streams and also recognizes that pumping effects on the aquifers must be limited (RDSGEIS, pp 6-5, -6). Regarding groundwater pumping, the "Department proposes to impose requirements regarding passby flows as stated in this document" (RDSGEIS, p 7-25). The RDSGEIS does not discuss how the potential impacts to a stream will be estimated or how passby flows will be maintained, especially considering the lag time between groundwater pumping and the time for effects to manifest in the streams.

- *NYSDEC should prohibit groundwater pumping in tributary watersheds when analysis indicates that the time for a pumping effect to reach the stream is less than 30 days.*
- *NYSDEC should require a suitable groundwater analysis to estimate the effect on groundwater discharge to streams.*

The RDSGEIS indicates that industry has begun recycling more of its wastewater (RDSGEIS, p. 1-2). Recycling flowback water is good for reducing the amount of water to be disposed of, but it will not significantly decrease the water volume needed for fracking because the amount recovered as flowback is just 10 to 30 percent of the amount originally injected. Tracking the flowback to be recycled should be part of the new "Drilling and Production Waste Tracking" process (RDSGEIS, p. 1-13).

PROJECT MITIGATION MEASURES

The primary mitigation schemes proposed in the RDSGEIS are setbacks, which the RDSGEIS treats as additional precautionary measures (RDSGEIS, p. 1-11). This section considers whether

the setbacks are sufficient or arbitrary. A list in section 1.8 introduces additional precautionary measures; they are repeated in section 3.2.4. The following lists the proposed mitigation setbacks from the RDSGEIS and provides brief comment:

> "Well pads for high-volume hydraulic fracturing would be prohibited in the NYC and Syracuse watersheds, and within a 4,000-foot buffer around those watersheds."

The primary pathway if wells are prohibited within 4000 feet of the watershed boundary would be underground, since topography would cause contaminants to flow away from the watershed boundary, assuming this coincides with a topographic divide. In general, 4000 feet is probably sufficient, but a site specific consideration of the geology should be included to ascertain that the groundwater divide would not place the well within the watershed and that geologic formations are not dipping in the direction of the watershed.

- *This setback is not specified in the regulations, but should be.*
- *The operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the prohibited watershed.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (6 NYCCR §560.4(a)(2),(subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing)"

The implication of only a 500 –ft setback is that there is no groundwater connection, but if groundwater in the bedrock connects with the aquifer, there is a potential for a rapid transport of contaminants from a spill through fractures to the aquifer. Contamination will easily spread through the highly conductive aquifer (RDSGEIS, p. 6-37). The risk to the aquifer would be the same as to the prohibited watersheds, so there is no reason the distance should be different. If the ground surface slopes from the well to the primary aquifer, there is a significant risk of a spill reaching the aquifer through surface channels.

- *The prohibition in* 6 NYCCR §560.4(a)(2) *should be increased to 4000 feet, unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.*
- *Additionally, the RDSGEIS should publish the area the Marcellus shale zone overlapped by primary aquifers and the area that would be included as buffer; this would help the public to understand how much land the prohibition affects.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (6 NYCCR

§560.4(a)(4)) (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing)"

Essentially, there is no reason for this offset to be less than the offset from a primary aquifer. Considering a public water supply well, the operator should be required to perform a capture zone analysis for the well, and if the well could draw contaminants from a spill to the well, the gas well should not be permitted in that location.

- *The setback for public water supply wells should also be 4000 feet.*
- *Additionally, the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.*

"The Department would not issue permits for proposed high-volume hydraulic fracturing at any well pad in 100-year floodplains". (6 NYCCR §560.4(a)(4))

For wells that might operate for 30 years, there is a 26% chance[2] of a 100-year flood occurring during the period the well would be operated.

- *Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.*

"The Department would not issue permits for proposed high-volume hydraulic fracturing at any proposed well pad within 500 feet of a private water well or domestic use spring, *unless waived by the owner*." (6 NYCCR §560.4(a)(4)), emphasis added.)

NYSDEC should not allow the owner to waive this requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.

- *6 NYCCR §560.4(a)(1) should be changed to remove the waiver from the water well owner unless the owner is required to disclose the waiver to a future buyer in perpetuity.*

In general, some of the points discussed above mention that NYSDEC will revisit the need for the setback in the future. These reconsiderations are not part of the regulations. If so, the NYSDEC should specify in detail the performance standards that must be met in order for the setback requirement to be relaxed, and should acknowledge that a supplemental EIS would be completed to consider those changes.

[2] The probability that a event with a p probability will occur during n observations (years) may be determined with a binomial distribution.

The RDSGEIS also specified the following factors which would require site-specific SEQRA analysis.

1) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone is shallower than 2,000 feet along any part of the proposed length of the wellbore.
2) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along any part of the proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply.
These requirements should be considered together – if the top of the shale is less than 2000 feet bgs or 1000 feet below the bottom of the aquifer, a site-specific SEQRA review will be required. The depths seem arbitrary, and must be based on a perceived potential for vertical transport from the shale to the receptor.

3) Any proposed well pad within 500 feet of a principal aquifer:
The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.

4) Any proposed well pad within 150 feet of a perennial or intermittent stream, storm drain, lake or pond:
Again, rather than allowing development subject toa site-specific study, development within 150 feet of these streams should be prohibited. It is difficult to imagine how study will prevent a spill which is, by its nature, unexpected.

5) A proposed surface water withdrawal that is found not to be consistent with the Department's preferred passby flow methodology as described in Chapter 7;
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6) Any proposed water withdrawal from a pond or lake;
7) Any proposed ground water withdrawal within 500 feet of a private well;
8) Any proposed ground water withdrawal within 500 feet of a wetland that pump test data shows would have an influence on the wetland:
Requirements 5 through 8 are acceptable limits for requiring site-specific study.

9) Any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure

This applies to areas outside the NYC watershed that contain NYC infrastructure (RDSGEIS, p 6-1). It is unclear whether there is any infrastructure that would actually be affected by fracking outside of the watershed. Fracking should not be allowed within 1000 feet of any NYC water supply infrastructure to prevent damage.

Acid Rock Drainage

The RDSGEIS refers in several locations to an acid rock drainage (ARD) mitigation plan which would be required for the on-site burial of Marcellus Shale cuttings (RDSGEIS, p 7-67). In general, our recommendation is that on-site burial not be allowed (see the report by Harvey Consulting, LLC). NYSDEC does not describe an adequate mitigation plan to prevent the leaching of ARD into groundwater. It does not specify testing which is essential to know how much neutralizing rock must be supplied.

For each well, prior to disposal of the cuttings, an adequate set of samples should be collected from the cuttings to test for acid generation. Adequate sampling would be representatively spaced along the horizontal well bore; initially, many samples would be needed to determine the variability among samples; samples every 100 feet would be desirable until sufficient data is collected from New York shales to characterize the variability along the horizontal well bore.

At least three types of testing should be completed:

- Acid base accounting – Modified Sobek procedure
- Net acid/alkaline production
- Meteoric water mobility testing – ASTM E-2242-02

These tests should provide adequate information to determine the amount of neutralizing rock which should be added to the cuttings to prevent ARD from leaching through the waste. Ideally, if the rock is potentially acid generating (PAG), kinetic tests should be completed to better assess the PAG potential, but this may not be possible in a timely fashion. The regulations should reflect these testing requirements. Final disposal must include adequate encapsulation to assure neutralization in perpetuity. It must also include adequate monitoring to assure that ARD does not leach into the underlying groundwater. A mitigation plan must be in place to remediate any disposal sites that do leak ARD.

COMMENTS ON SPECIFIC PROPOSED REGULATIONS

The proposed regulations increase the overlap lengths for cement plugs in abandoned O&G wells from 15 to 50 feet at several locations (6 NYCRR§ 555.5(a)). This increase in plug length is an improvement but not sufficient or well planned in all locations. Rather than filling "with

cement from total depth to at least 50 feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity" (6 NYCRR§ 555.5(a)(1)), the regulation requiring cementing to 50 feet above the top of the shallowest formation in which gas has been observed; not all gas pockets have actually produced gas but could cause methane contamination if they are not already sealed off by casing. The regulations should specify that the cement plug "below the deepest potable fresh water level" should overlap the transition than be just below it because even a short section of uncased well bore open to the salt water could mix into the well and to above the fresh water line (6 NYCRR§ 555.5(a)(3)).

The definition of "public water supply" (6NYCRR§ 560.2(19)) appears to include only groundwater by referring to "a…well system which provides piped water". However, the definition of "reservoir" (6NYCRR§ 560.2(20)) includes "waterbody designated for use as a dedicated public water supply". The regulations must clear up this inconsistency by making clear that a "public water supply" includes ground- and surface water.

Operators must include in their applications various items (6NYCRR§ 560.3). The following address some of these requirements by number (the setback requirements were addressed above in the section concerning setbacks).

(2): The estimated maximum depth and elevation of bottom of potential freshwater: The operator should also be required to complete geophysical logging including conductivity measurements to verify the depth, unless it had been based on "previous drilling on the well pad".

(3): The "proposed volume of water to be used in hydraulic fracturing": The operator should also be required to discuss and specify how the estimated volume was determined.

(5), (6): The two parts specify that the application will provide the distance to various features but only if they are within a given specific distance. With current geographic information systems technology, there is no difficulty in obtaining these distances. The application should provide the distance to the water supply features in (5) and the aquifer and stream features in (6) if they are within two miles.

Mapping requirements for the application are specified in 6 NYCCR § 560.3(b). The topographic map requirements (6 NYCCR § 560.3(b)(2) require essentially a site map within 2640 feet of the proposed surface location (RDSGEIS, p. 3-9). This should be increased to 1 mile from the site, so that the map would be two by two miles centered on the proposed well pad. The map should include locations of all aquifers, water wells, stream channels, and other water features. The map should also include surface geology including faults. If fractures dominate the surface bedrock, contaminants can move quickly to wells. Contaminant pathways for transport from

the pad should be identified on the map. Contaminants would not move far upgradient, so the NYSDEC should focus downgradient. The following recommendations should be included in regulations regarding the requirements of well drillers to take steps to protect nearby wells.

- *The operator should complete site specific geology/hydrogeology studies to map the potential flow paths for contaminants released from the well pad or the well bore.*
- *All wells within a five-year transport zone should be located and included in sampling plans discussed below. Additionally, dedicated monitoring wells should be established within this zone, also as described below.*

The regulations require the operator to record and report the depths and flow rates where "freshwater, brine, oil and/or gas were encountered or circulation was lost during drilling operations" (6 NYCCR 560.6(c)(22)). The operator should identify these areas with specific conductivity logging. The regulations do not specify any limits or actions that the operator should take if certain flow or losses were recorded; they do not specify what the department will do with this information.

The required treatment plan "must include a profile showing anticipated pressures and volumes of fluid for pumping the first stage" (6 NYCCR 560.6(c)(22)). The operator also "must make and maintain a complete record of it hydraulic fracturing operation including the flowback phase" (6 NYCCR 560.6(c)(26)viii). The operator should compare the "anticipated pressures and volumes" with the actual values.

The operator must suspend operations immediately "if any anomalous pressure and/or flow conditions is indicated or occurring which is a significant deviation from either the treatment plan" (6 NYCCR 560.6(c)(26)vii). This is good, but the regulations do not define anomalous or what a significant deviation from the treatment plan would be, or what the follow-up action would be to assess and remedy damages.

Also, the required record of the fracking operation, 6 NYCCR 560.6(c)(26)viii, includes rates, volumes, and pressures of all injected and flowback fluids to the well. The department only requires a synopsis be provided to the department. There is no description what a synopsis should include. Instead, the department should require the full record be provided to the department, and this record should be made publically available online.

The regulations allow a well owner to waive setback requirements (6NYCRR§ 560.4(a)(1)). This should not be allowed unless there is also a requirement to inform potential purchasers of the well in the future of the waiver.

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APPENDIX A

Review of Appendix 11, Excerpt from ICF Report, Task 1, 2009

Analysis of Subsurface Mobility of Fracturing Fluids

Agreement No. 9679

Reviewed by

Tom Myers, Ph.D.

Hydrologic Consultant

Reno, NV

December 7, 2009

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Introduction

The New York State Energy and Development Authority (NYSERDA) contracted with ICF International to prepare a review of the hydraulic fracturing process as it will likely be applied to the Marcellus Shale in New York; this review was published as a supporting document for the 2009 RDSGEIS prepared by the New York State Department of Environmental Conservation. For the 2011 RDSGEIS, Appendix 11 presents excerpts from that report regarding the subsurface mobility of fracturing fluids. This is a review of Appendix 11, revised from a review completed by this author of the ICF International report contained in the 2009 RDSGEIS.

In summary, ICF completed an analysis of the potential for contamination to flow from the shale to freshwater aquifers, but misrepresented the actual situation in many ways. The basic problem was they conceptualized the flow potential incorrectly. They considered the gradient incorrectly and assumed that if the transport did not occur within the time period of fracturing, it would not occur. They assumed that the fluids leaving the shale would completely disperse, and be diluted, by occupying and being retained in every pore between the shale and the aquifers. They did not consider preexisting fractures. They ignored any potential pre-existing vertical gradient which would drive contaminants leaving the shale to the aquifers. Although they presented a geochemical analysis which could explain why some attenuation could occur, they provided no site specific or fluid specific data to indicate that it would occur.

Exposure Pathways

ICF analyzes the potential for fracturing fluid to flow from the shale to the freshwater aquifers anywhere from 1000 to 5000 feet above. The first problem is that the potential contaminants are both fracturing fluid and connate (formation) water existing in the shale before fracturing, which could contain extremely high concentrations of TDS, benzene, or radioactive materials. Therefore, ICF should have considered the potential for flow of both fracturing fluid and connate water. Ambient water could both be pushed from the shale by the injection of fracturing fluid and just by the opening of the pore spaces which would increase the permeability and allow more of a natural connection.

ICF calculates the gradient between the fracture zone and the bottom of the freshwater zone, which they set at 1000 feet bgs to be conservative in because much of the groundwater below this level in southern New York is not an underground source of drinking water either because it is too salty or the formation is not sufficiently productive to be considered an aquifer. However, their calculation applied only during the period of injection. Myers (in review) demonstrated through modeling that the fracking pressure would dissipate over a period of months, not immediately after fracking ended, because of the fluid that has been pushed away from the well. The effective gradient is from the well to just beyond the migrating fluid where pressures would not yet have been affected by the current fracking.

ICF also ignores the potential for a natural upward gradient, which could be due to natural artesian pressure. Myers (in review) also discusses the potential for this in detail.

ICF properly calculated the pressure that would occur in the shale during fracturing based on the effective stress in the formation and the amount of pressure required to overcome the in-situ horizontal stress (ICF, pages 25-26); accepting the assumptions in the following quote, equation 12, and equations 7 through 11 used to derive it, is an accurate description of the head applied to the shale during fracturing.

> Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of the geologic materials (estimated at 150 pcf average), times the depth. To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress… (ICF, pages 25-26)

ICF uses that equation with the gradient equation 6 to estimate the gradient between the shale and freshwater aquifer, “during hydraulic fracturing”, for a variety of depths of the aquifer and the shale. The numbers are correct, for an aquifer depth of 1000 feet and shale depth of 2000 feet, they show the gradient to be about 3.6, but the concept applied in the derivation is wrong as described above. During hydraulic fracturing, variously estimated through the RDSGEIS

documents as occurring for up to 5 days, there is no hydraulic connection between the shale and the bottom of the freshwater aquifer and it is therefore inappropriate to consider the gradient across that thickness. The correct conceptualization is described in the following paragraph.

Upon applying a pressure in the shale, as occurs during the injection for fracturing, a very high pressure head is developed at the well and nearby shale. This pressure causes the gradient that drives the fluid away from the well into the shale, where it causes the shale to fracture. Fluid may continue to flow into surrounding formations. During the process, the pressure begins to increase away from the well which establishes a steep gradient near the well. Away from the well at any given time during injection, the pressure is less than at the well. The pressure drop from the well to any point in the shale away from the well is a function of the friction incurred by the fluid flowing away from the well. At some distance from the well, the pressure is only at background. The distance at which the pressure is only background is the point at which the injection fluid has not yet reached. Beyond the point to which the injection fluid flows, there is NO hydraulic connection. For this reason, ICF's calculation for gradient between the injection pressure in the shale and the bottom of the freshwater aquifer is hydrogeologically incorrect. ICF is effectively analyzing a steady state situation that would occur if the injection pressure continued until the pressure stabilized between the shale and the freshwater aquifer.

ICF acknowledges the reality that transient or non-steady conditions will prevail and that the actual pressure gradient will be higher closer to the shale. "In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer to the fracture zone and lower than the average closer to the aquifer." (ICF, pages 26-27)

However, they do not carry the analysis any further and seem to argue that immediately after injection ceases, all upward gradient will cease: "It is important to note that these gradients only apply while fracturing pressures are being applied. Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer" (ICF, page 27). The implication from this statement is that ending injection will cause the pressure in the reservoir to drop back to background, immediately. This is not possible, any more than it is possible for the drawdown in a pumping well in an aquifer to return to pre-pumping conditions immediately upon cessation of pumping.

For example, consider that during a five-day injection period, the pressure propagated outward from the well as described in Myers (in review). When injection ends, the pressure within the well may almost immediately return to background, but the pressure in the surrounding formation will still be very high. This is the pressure which will drive the flowback to the well, as described throughout the RDSGEIS. The initial flowback is fluid right next to the well – the

fluid that had just been injected. The pressure field created in the formation away from the well is the pressure that causes a gradient to push the fluid back into the well.

As long as there is flowback, there is a gradient toward the well, and residual pressure in the shale or surrounding formations. With distance from the well, the pressure increases (as required for there to be a gradient back to the well). At any given time, there will be a point of maximum pressure beyond which the pressure becomes lower; in other words, a cross-section through the formation away from the well showing the pressure head would show the pressure rising from the well to the peak and falling from the peak to the point the pressure reaches background. (This is similar to the concept in hydrogeology that during pumping, the maximum drawdown caused by a well is at the well; when the well ceases to pump, the water level will initially rise quickly, but the drawdown away from the well will continue to expand for a period of time.)

ICF considers that local drawdown caused by production from the well will further prevent flow away from the well: "During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow" (ICF, page 27). This is probably correct, but the process described in the preceding paragraph likely causes some of the fluid to have moved beyond this propagating drawdown. The fact that only 35% of the injected fluid returns as flowback (RDSGEIS, Gaudlip et al, 2008) would seem to confirm that much of the injected fluid gets beyond the point where the reversing gradient would pull the fluid back to the well.

ICF also relies on there being no connection between the shale and surrounding formations, as indicated by the high TDS content of water in the shale. This may reflect the pre-fractured conditions, but the fracturing process could open a connection between formations. As noted in the main body of this review, out-of-zone fracking is not uncommon, therefore it is reasonable to assume that connections between the shale and surrounding formations do occasionally occur.

The analysis provided by ICF in section 1.2.4.3, Seepage Velocity, is irrelevant because it considers the velocity between the shale and the freshwater aquifer, using a gradient established in the previous section that only applies for as long as the injection. Their calculation of 10 ft/day (ICF, page 28) relies on that average gradient. They seem to acknowledge the fallacy of their assumptions by stating: "The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata" (ICF, page 28, emphasis added). ICF carries the error into section 1.2.4.4, Required Travel Time, by calculating how long it would take for flow at the seepage velocity calculated in the previous section to reach the freshwater aquifers.

ICF's fourth argument is that even if all of the injected fluid moves vertically out of the shale towards the freshwater aquifer, it would have to disperse among all of the pores between the shale and the aquifer – a truly nonsensical idea. The calculation requires that 4,000,000 gallons of fluid would be evenly dispersed throughout a 40-acre well spacing. In other words, they assume that about 4,000,000 gallons of injected fluid would evenly disperse through all of the void, assuming porosity of 0.1, over a 1000-foot thickness 40 acres in area, or about 1.3 billion gallons of void space, would cause a dilution factor of 300 (ICF, pages 30-31). This is wrong for the following reasons.

- An injected fluid would move as a slug along the gradient. In this case, with a natural upward gradient, any fluid that escapes the well bore (does not flowback) would disperse upward. It would not diffuse through every pore space between the shale and aquifer. Advective forces would move it upward as a slug with dispersion spreading it out both vertically and horizontally. It will dilute, but far less than postulated by ICF's analysis.
- The vertical flow would follow preferential flow paths rather than advecting upwards uniformly across 40 acres. The image painted by ICF is that the fluid would flow upward to the aquifer with the leading edge moving at exactly the same rate over the entire area. Even if there are no fractures, faults, or improperly plugged wells, simple finger flow, caused by heterogeneities in the material properties, would cause an uneven distribution of the contaminant.

ICF also rejects the concept of fractures, faults, or unplugged wells by claiming it is "extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer" (ICF, page 31). They provide no data or references to assess the probability that such a network is "extremely unlikely" or to justify their conclusion. More importantly, for fractures to facilitate a connection between the shale and the aquifers, it is not necessary for the fracture to exist over the entire thickness. As ICF (page 5) mentions, the Marcellus Shale has substantial natural fractures, and therefore it is possible that the surrounding formations, sandstone or shale, also have fractures. It is not necessary for the flow to follow a fracture all the way to the aquifers, but it could enhance the velocity of movement. Fractures could also further disperse the flow vertically, as discussed in Myers (in review).

ICF also mentions geochemistry as a reason that transport of contaminants from the shale to the aquifers will not occur. While it is possible for attenuation to occur as contaminants move through a formation, without site specific and chemical specific data, they should not make such an argument.

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APPENDIX B

Prepublication Copy

Myers, T., in review. POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

Tom Myers

Hydrologic Consultant

Reno NV

Tom_myers@charter.net

ABSTRACT

Hydraulic fracturing (fracking) of deep shale beds to develop natural gas has caused concern regarding the potential for various forms of water pollution. Two potential pathways – diffuse transport through bulk media and preferential flow through fractures – could allow the transport of contaminants from the fractured shale to aquifers. There is substantial geologic evidence that natural vertical flow drives contaminants, mostly brine, to near the surface from deep evaporite sources. Interpretative numerical modeling shows that diffuse transport could require up to tens of thousands of years to move contaminants to the surface, but also that fracking the shale could reduce that transport time to tens or hundreds of years. Conductive faults or fracture zones, as found throughout the Marcellus shale region, could reduce the travel time further. Injection of up to 15,000,000 liters of fluid into the shale generates high pressure at the well which decreases with distance from the well and with time after injection as the fluid advects through the shale. The advection displaces native fluids, mostly brine, and fractures the bulk media and widens existing fractures. Simulated pressure returns to pre-injection levels in about 90 days. The overall system requires from three to six years to reach a new equilibrium reflecting the significant changes caused by fracking the shale. The rapid expansion of hydraulic fracturing requires that monitoring systems be employed to track the movement of contaminants and that gas wells have a reasonable offset from faults.

Introduction

The use of natural gas (NG) in the United States has been increasing, with 53 percent of new electricity generating capacity between 2007 and 2030 projected to be with NG-fired plants (EIA 2009). Unconventional sources account for a significant proportion of the new NG available to the plants. A specific unconventional source has been deep shale-bed NG, including the Marcellus shale primarily in New York, Pennsylvania, Ohio, and West Virginia (Soeder 2010), which has seen over 4000 wells developed between 2009 and 2010 in Pennsylvania (Figure 1).Unconventional shale-bed NG differs from conventional sources in that the permeability is so low that gas does not naturally flow in timeframes suitable for development. Hydraulic fracturing (fracking, the industry term for the operation (Kramer 2011)) loosens the formation to release the gas and provide pathways for it to move to a well.

Fracking injects 13 to 19 million liters of fluid consisting of water and additives, including benzene at concentrations up to 560 ppm (Jehn 2010), at pressures up to 69,000 kPa (PADEP 2011) into low permeability shale to force open and connect the fractures. This is often done using horizontal drilling through the middle of the shale. Horizontal wells may be more than a kilometer (km) long. The amount of injected fluid that returns to the ground surface after fracking ranges from 9 to 34 percent of the injected fluid (Alleman 2011; NYSDEC 2009), although some would be formation water.

Many agency violation reports and legal citations (ODNR 2008; PADEP 2009) and peer-reviewed articles (DiGuilio et al. 2011; Osborn et al. 2011; Breen et al. 2007; White and Mathes 2006) have found more gas in water wells near areas being developed for unconventional NG, documenting the source can be difficult. One reason for the difficulty is the different sources – thermogenic for gas formed by compression and heat at depth in shale and bacteriogenic for gas formed by bacteria breaking down organic material (Schoell 1980). The source can be distinguished based on both C and H isotopes and the ratio of methane to higher chain gases (Osborn and McIntosh 2010; Breen et al 2007). Thermogenic

gas can reach aquifers only by leaking from the well bore or by seeping vertically from the source. In either case, the gas must flow through potentially very thick sequences of sedimentary rock to reach the aquifers. Many studies which have found thermogenic gas in water wells found there to be more gas near fracture zones (DiGuilio et al. 2011; Osborn et al. 2011; Thyne 2008; Breen et al. 2007), suggesting that fractures are pathways for gas to move from shale or other deep formations to aquifers.

A pathway for gas would also be a pathway for fluids and contaminants to advect from the fractured shale to the surface, although the time for transport would likely be longer. Two reports (DiGuilio et al. 2011; EPA, 1987) have documented the presence of fracking fluid in aquifers and another found elevated chloride (Thyne 2008), linked to fracking, in wells, although the exact source and pathways had not been determined.

There is sufficient documented gas movement and circumstantial evidence regarding fluids movement to suggest that there is a potential for fracking fluid or shale-bed formation fluid to reach aquifers. With the vastly increasing development of unconventional NG sources, the risk to aquifers could seemingly be increasing. However, there is almost no data concerning the movement of contaminants along pathways from depth, either from wellbores or from deep formations, to aquifers. The only way in the short term to explore the risk is with conceptual analyses.

To consider the potential transport from depth to aquifers, I have considered first the potential pathways for contaminant transport through bedrock between deep shale and surface aquifers, and the necessary conditions for such transport to occur. Second, I have estimated contaminant travel times through the potential pathways, with a bound on these estimates based on formation hydrologic parameters, using interpretative MODFLOW-2000 computations. The modeling does not, and cannot, account for all of the complexities of the geology, which could either increase or decrease the travel

times compared to those considered herein. The intent of this study is to characterize the risk factors, so the modeling is used, similar to that by Hsieh (2011), to consider the possibilities.

The Marcellus shale area of northern Pennsylvania and southern New York is the study area (Figure 1), although the concepts should apply anywhere there is a deep unconventional NG source separated from the surface by sedimentary rock.

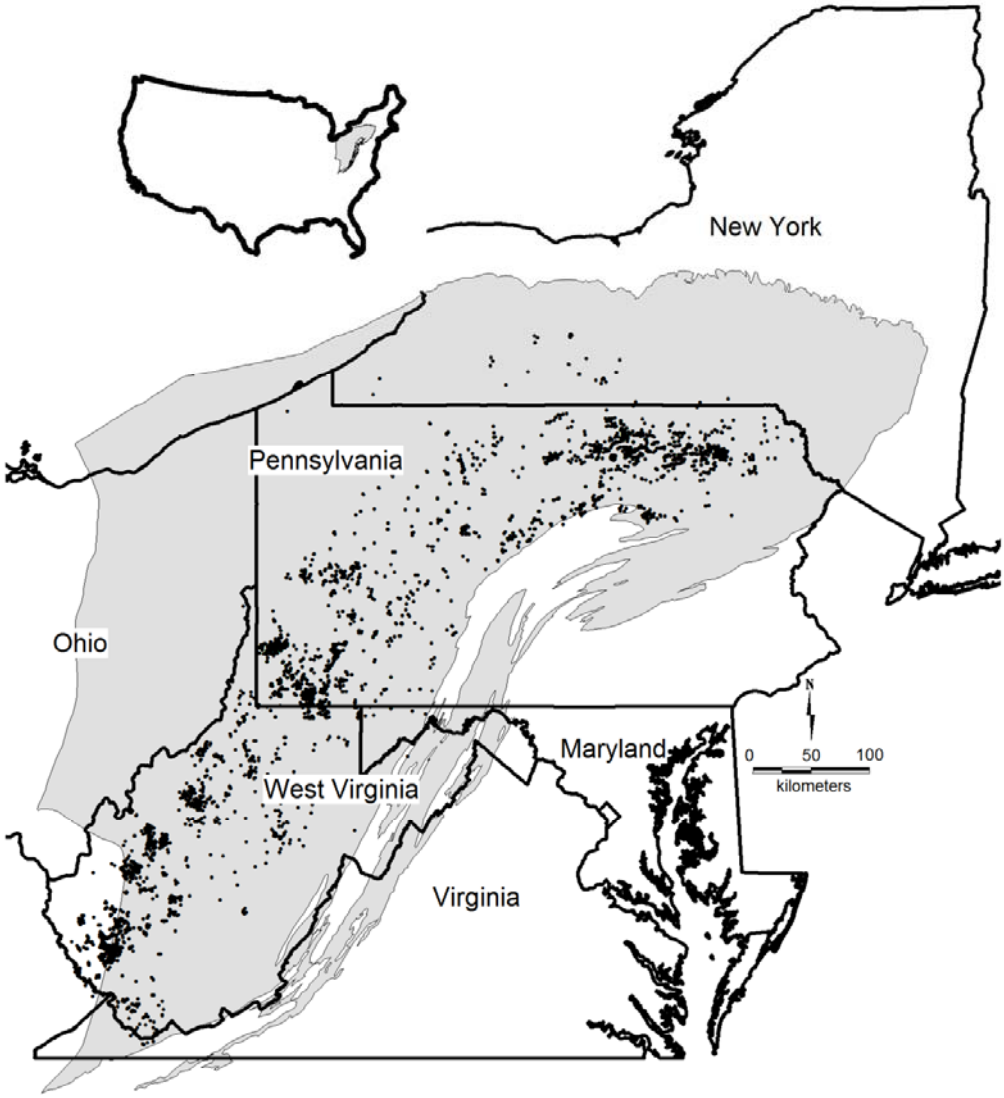

Figure 2: Location of Marcellus shale in northeastern United States. Location of Marcellus wells (dots) drilled July 2009 to June 2010 and total Marcellus shale wells in New York and West Virginia. There are 4064 wells shown in Pennsylvania, 48 wells in New York, and 1421 wells in West Virginia. Faulting in the area may be found in PBTGS (2001), Isachsen and McKendree (1977), and WVGES (2011, 2010a and 2010b).

Method of Analysis

I consider several potential scenarios of transport from shale, 1500 m below ground surface to the surface, beginning with pre-development steady state conditions to establish a baseline and then scenarios considering transport after fracking has potentially caused contaminants to reach the overlying formations. To develop the conceptual models and MODFLOW-2000 simulations, it is necessary first to consider the hydrogeology of the shale and the details of hydraulic fracturing, including details of how fracking changes the shale hydrogeologic properties.

Hydrogeology of Marcellus Shale

Shale is a mudstone, a sedimentary rock consisting primarily of clay- and silt-sized particles, which tend to break in one direction (Nichols 2009). It forms through the deposition of fine particles in a low energy environment, such as a lake- or seabed. The Marcellus shale formed in very deep offshore conditions during Devonian time (Harper 1999) where only the finest particles had remained suspended. Because sufficient organic matter settled with the clay and silt, anaerobic decomposition caused the formation of methane. The depth to the Marcellus shale varies to as much as 3000 m in parts of Pennsylvania, and averages about 1500 m in southern New York. Between the shale and the ground surface are layers of sedimentary rock, including sandstone, siltstone, and shale (NYSDEC 2011).

Marcellus shale has very low natural intrinsic permeability, on the order of 10^{-16} Darcies (Kwon et al. 2004a and 2004b; Neuzil 1994 and 1986), which makes it an extremely efficient seal, or capstone, for keeping natural gas in underlying sandstone. At a gradient equal to 1 with an intrinsic permeability equal to 100×10^{-9} darcies, water would flow only 0.000025 m in a year.

Schulze-Makuch et al. (1999) described Devonian Shale of the Appalachian Basin, of which the Marcellus is a major part, as containing “coaly organic material and appear either gray or black” and being “composed mainly of tiny quartz grains < 0.005 mm diameter with sheets of thin clay flakes”. Median

particle size is 0.0069±0.00141 mm with a grain size distribution of <2% sand, 73% silt, and 25% clay. Primary pores are typically 5 x 10^{-5} mm in diameter, matrix porosity is typically 1% to 4.5% and fracture porosity is typically 0.078 to 0.09% (Schulze-Makuch et al. 1999 and references therein).

The Marcellus shale is fractured by faulting and contains synclines and anticlines which cause tension cracks (Engelder et al. 2009; Nickelsen 1986). It is sufficiently fractured in some places to support water wells just six to ten km from where it is being developed for NG at 2000 m below ground surface (bgs) in eastern Lycoming County, Pennsylvania (Lloyd and Carswell 1981) (Figure 2).

Porous flow in unfractured shale is negligible due to the low bulk media permeability, but at larger scales the fractures control and may allow significant flow. Conductivity scale dependency (Schulze-Makuch et al.1999) may be described as follows:

$$K = Cv^m$$

K is hydraulic conductivity (m/s), C is the intercept of a log-log plot of observed K to scale (the K at a sample volume of 1 m^3), V is sample volume (m^3), and m is a scaling exponent determined with log-log regression; for Devonian shale, C equals -14.3 and m equals 1.08 (Schulze-Makuch et al. 1999). Most of their samples were small because the deep shale is not easily tested at a field-scale and no groundwater models have calibrated for flow through the Marcellus shale, therefore field scale K estimates are uncertain. Considering a 1 km square area with 30 m thickness, the Kh would equal 5.96x10^{-7} m/s (0.0515 m/d). This effective K is low and the shale would be an aquitard, but a leaky one.

Contaminant Pathways from Shale to the Surface

Three studies (Osborn et al. 2011; Thyne 2008; Breen et al. 2007) have found gas in near-surface water wells and suggested that the most likely cause was vertical transport of gas from depth, possibly linked to the presence of faults through which the gas could flow. Osborn et al. (2011) found systematic

circumstantial evidence for higher methane concentrations in wells within 1 km of Marcellus shale gas wells that had been fracked. Gas moves through fractures depending their width (Etiope and Martinelli 2001) and is a primary concern for many projects, including carbon sequestration (Annunziatellis et al. 2008) and natural gas storage projects (Breen et al. 2007).

Pathways for gas suggest pathways for fluids and contaminants, if there is a gradient. Vertical hydraulic gradients of a up to a few percent, or about 30 m over 1500 m, exist throughout the Marcellus shale region as may be seen in various geothermal developments in New York (TAL 1981). Brine more than a thousand meters above their evaporite source (Dresel and Rose 2010) is evidence of upward movement of contaminants from depth to the surface. The Marcellus shale, with salinity as high as 350,000 mg/l (Soeder 2010; NYDEC 2009), may be a primary brine source. Relatively uniform brine concentrations over large areas (Williams et al. 1998) suggest widespread diffuse transport, which would occur if there is a sufficient concentration gradient. The transition from briny to freshwater suggests a long-term equilibrium between the upward movement of brine and downward movement of freshwater.

Faults, which occur throughout the Marcellus shale region (Gold 1999), could provide pathways (Caine et al. 1996; Konikow 2011) for more concentrated advective and dispersive transport. Brine concentrating in faults or anticline zones reflects potential preferential pathways (Wunsch 2011; Dresel and Rose 2010; Williams 2010; Williams et al. 1998).

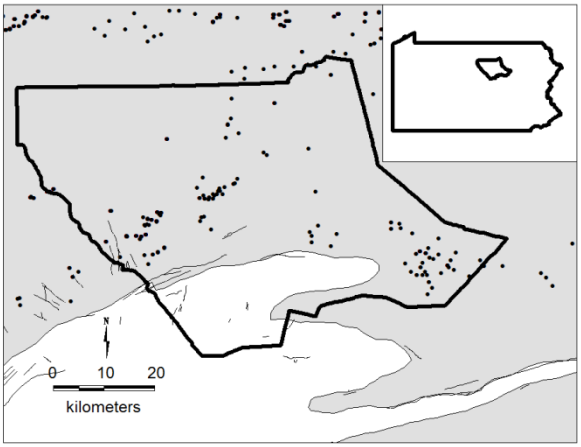

Figure 3: Marcellus shale wells and the Marcellus outcrop in Lycoming County, Pennsylvania. The grey shading is the area of Marcellus shale, which outcrops along its boundary along an area about 1 km wide (Lloyd and Carswell 1981). Faults from PBTGS (2001).

Effect of Hydraulic Fracturing on Shale

Fracking increases the permeability of the targeted shale to make extraction of natural gas economically efficient (Engelder et al. 2009; Arthur et al. 2008). Fracking creates fracture pathways with up to 9.2 million square meters of surface area in the shale accessible to a horizontal well (King 2010; King et al. 2008) and connects natural fractures (Engelder et al. 2009; King et al. 2008). No post-fracking studies that documented hydrologic properties such as conductivity were found while researching this article (there is a lack of information about pre- and post-fracking properties (Schweitzer and Bilgesu 2009)), but it is reasonable to assume the K increases significantly because of the newly created and widened fractures.

Fully developed shale typically has wells spaced at about 300-m intervals (Krissane and Weissert 2011; Soeder 2010). Up to eight wells may be drilled from a single well pad (NYDEC 2009; Arthur et al. 2008), although not in a perfect spoke pattern. Reducing by half the effective spacing did not enhance overall productivity (Krissane and Weissert 2011) which indicates that 300–m spacing creates sufficient overlap among fractured zones to assure adequate gas drainage. The properties controlling groundwater flow

would therefore be affected over a large area, not just at a single horizontal well or set of wells emanating from a single well pad.

Fracking is not intended to affect surrounding formations, but shale properties vary over short ranges (King 2010; Boyer et al. 2006) and out of formation fracking is not uncommon. Fluids could reach surrounding formations just because of the volume injected into the shale, which must displace natural fluid, such as the existing brine in the shale. For example, if 15 million liters is injected into shale over a 1000 m long horizontal well, the fluid could occupy all of the pore spaces within 7 to 16 m from the well for effective porosity ranging from 0.1 to 0.02. Even with 20% of the fluid returning to the well, a significant amount of existing pore space would be occupied by the injected fluid, displacing the existing brine and gas.

Analysis of Potential Transport along Pathways

Fracking could cause contaminant to reach overlying formations either by fracking out of formation, connecting fractures in the shale to overlying bedrock, or by simple displacement of fluids from the shale into the overburden. Advective transport will manifest if there is a significant vertical component to the regional hydraulic gradient. Advective transport can be considered with the simple particle velocity determined with Darcy velocity and effective porosity.

Numerical modeling provides flexibility to consider potential conceptual flow scenarios, but should be considered interpretative (Hill and Tiedeman, 2007). Numerical simulation presented herein was completed with the MODFLOW-2000 code (Harbaugh et al. 2000). The simulation considers the rate of vertical transport of contaminants to near the surface for the different conceptual models, based on an expected, simplified, realistic range of hydrogeologic aquifer parameters.

MODFLOW-2000 is a versatile numerical modeling code, but it is not perfect for all of the factors required for this simulation. The native water at depth near the shale is brine, much saltier than seawater, therefore the injected fluid would be lighter so buoyancy factors may speed the upward flux beyond the simple consideration of hydraulic gradient. As more data becomes available, it may be useful to consider the added upward force caused by the brine by using the SEAWAT-2000 module (Langevin et al. 2003).

Vertical flow would be perpendicular to the general tendency for sedimentary layers to have higher horizontal than vertical conductivity. Fractures and improperly abandoned wells would provide pathways for much quicker vertical transport than general advective transport. This paper considers the fractures as vertical columns with cells having much higher conductivity than the surrounding bedrock. The cell discretization is fine, so the simulated width of the fracture zones is realistic. Dual porosity modeling would not be useful because high velocity vertical flow through the fractures is unlikely. MODFLOW-2000 has a module, MNW (Halford and Hansen 2002), that could simulate flow through open bore holes. Open boreholes would clearly provide rapid transport if the head deep in the borehole exceeds that near the surface or if fractures containing fracking fluid intersect or come close to the borehole. Because it is possible to simply plug open boreholes, I have limited consideration here to fractures; however, models of well fields should include known boreholes.

The thickness of the formations and fault would affect the simulation, but much less than the several-order-of-magnitude variation possible in the shale properties. The overburden and shale thickness were set equal to 1500 and 30 m, respectively, similar to that observed in southern New York. The estimated travel times are proportional for thicker or thinner sections. The overburden could be predominantly sandstone, sections of shale, mudstone, and limestone could exert local control. The vertical fault is assumed to be 6 m thick.

There are five conceptual models of flow and transport of natural and post-fracking transport from the level of the Marcellus shale to the near-surface to consider with an interpretative numerical model.

1. The natural upward diffuse flow due to a head drop of 30 m from below the Marcellus shale to the ground surface, considering the variability in both shale and overburden K. This is a steady state solution for upward advection through a 30-m thick shale zone and 1500-m overburden and is a baseline condition for upward flow through unfractured sedimentary rock.
2. Same as number 1, but with a fracture zone connecting level of the shale with the surface. This emulates the conceptual model postulated for flow into the alluvial aquifers near stream channels, the location of which may be controlled by faults (Williams et al 1998). The fault K varies from 10 to 1000 times the surrounding bulk sandstone K.
3. This scenario tests the effect of extensive fracturing in the Marcellus shale by increasing the shale K from 10 to 1000 times its native value over an extensive area. This transient solution starts with initial conditions being a steady state solution from scenario 1. The K in the shale layers increases from 10 to 1000 times at the beginning of the simulation, to represent the relatively instantaneous change on the regional shale hydrogeology imposed by the fracking. This scenario estimates both the changes in flux and the time for the system to come to equilibrium after fracking.
4. As number 3, considering the effect of the same changes in shale properties but with a fault as in number 2.
5. This scenario simulates the actual injection of 13 to 17 million liters of fluid in five days into fractured shale from a horizontal well with and without a fault.

Model Setup

The model domain was 150 rows and columns spaced at 3 m to form a 450 m square (Figure 3) with 50 layers bounded with no flow boundaries. The 30-m thick shale was divided into 10 equal thickness layers from layer 40 to 49. The overburden layer thickness varied from 3 m just above the shale to layer 34, 6 m layer 29, 9 m to layer 26, 18 m in layer 25, 30 m to layer 17, 60 m to layer 6, 90 m to layer 3, and 100 m in layers 2 and 1

The model simulated vertical flow between constant head boundaries in layers 50 and 1, as a source and sink, so that the overburden and shale properties control the flow. The head in layers 50 and 1 was 1580 and 1550 m, respectively, to create an upward gradient of 0.019 over the profile. Varying the gradient would have much less effect on transport than changing K over several orders of magnitude and was therefore not done.

This simulation considers particle travel times between the top of the shale and the top of the model domain based on an effective porosity of 0.1. A 6-m wide fault is added for some scenarios in the center two rows from just above the shale, layer 39 to the surface. The fault is an attempt at considering fracture flow, but the simulation treats the six meter wide fault zone as homogeneous, which could underestimate the real transport rate in fracture-controlled systems. The simulation also ignores diffusion between the fracture and the adjacent shale matrix (Konikow, 2011).

Scenario 5 simulates injection using a WELL boundary in layer 44, essentially the middle of the shale, from columns 25 to 125 (Figure 3). It injects 15 million liters over one 5-day stress period, or 3030 m^3/d into 101 model cells at the WELL. The modeled shale K was changed to its assumed fracked value at the beginning of the simulation. Simulating high rate injection generates very high heads in the model domain, similar to that found simulating oil discharging from the well in the Deepwater Horizon crisis (Hsieh, 2011) and water quality changes caused by underground coal gasification (Contractor and El-

Didy 1989). DRAIN boundaries on both sides of the WELL simulated return flow for sixty days after the completion of (Figure 3), after which the DRAIN was deactivated. The sixty days were broken into four stress periods, 1, 3, 6, and 50 days long, to simulate the changing heads and flow rates. DRAIN conductance was calibrated so that 20% of the injected volume returned within 60 days to emulate standard industry practice (Alleman 2008; NYSDEC 2009). Recovery, continuing relaxation of the head at the well and the adjustment of the head distribution around the domain, occurred during the sixth period which lasted for 36,500 days, a length of time that simulation of scenarios 3 and 4 indicated would suffice.

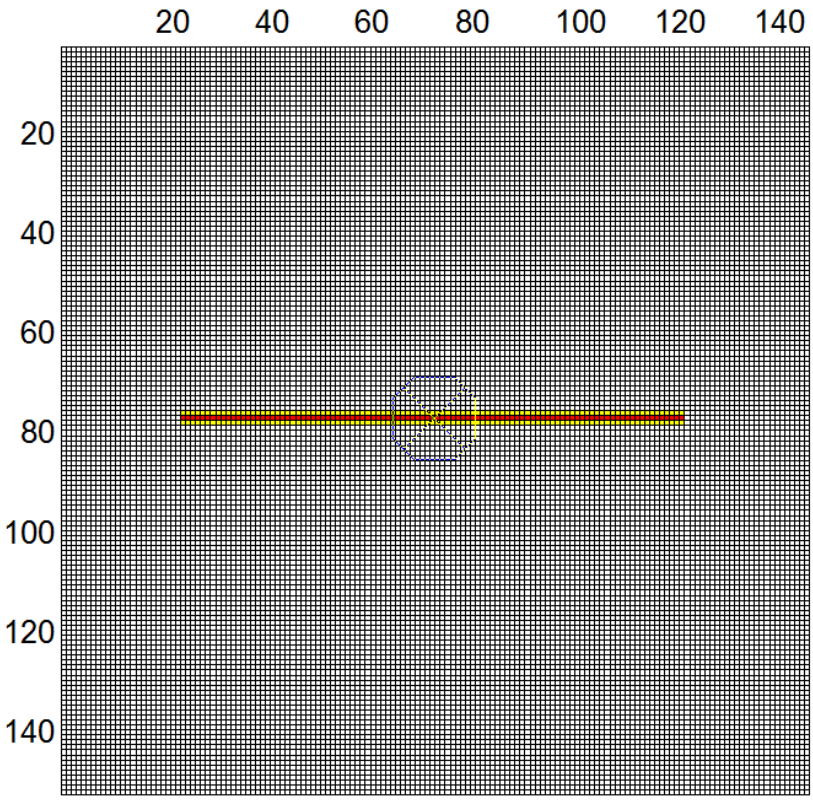

Figure 4: Model grid through layer 44 showing the horizontal injection WELL (red) and DRAIN cells (yellow) used to simulate flowback. The figure also shows the monitoring well.

There is no literature guidance to a preferred value for fractured shale storage coefficient, so I estimated S with a sensitivity analysis using scenario 3. With fractured shale K equal to 0.001m/d, two orders of magnitude higher than the in-situ value, the time to equilibrium resulting from simulation tests of three fractured shale storage coefficients, 10^{-3}, 10^{-5}, and 10^{-7} m^{-1}, varied twofold (Figure 4). The slowest time to equilibrium was for $S=10^{-3}$ m^{-1} (Figure 4), which was chosen for the transient simulations because more water would be stored in the shale and flow above the shale would change the least.

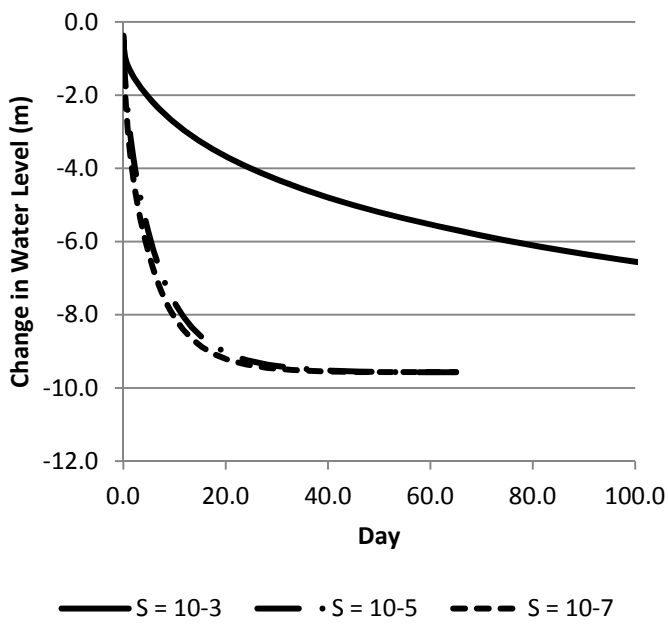

Figure 5: Sensitivity of the modeled head response to the storage coefficient used in the fractured shale for model layer 39 just above the shale.

Results

Scenario 1

The travel time for a particle to transport through 1500 m of sandstone and shale equilibrates with one of the formations controlling advection (Figure 5). For example, when the shale K equals $1x10^{-5}$ m/d, transport time does not vary with sandstone K. For sandstone K at 0.1 m/d, transport time for varying

shale K ranges from 40,000 years to 160 years. The lower travel time estimate is for shale K similar to that found by Schulze-Makuch et al. (1999). The shortest simulated transport time of about 20 years results from both the sandstone and shale K equaling 1 m/d. Other sensitivity scenarios emphasize the control exhibited by one of the media (Figure 5). If shale K is low, travel time is very long and not sensitive to sandstone K.

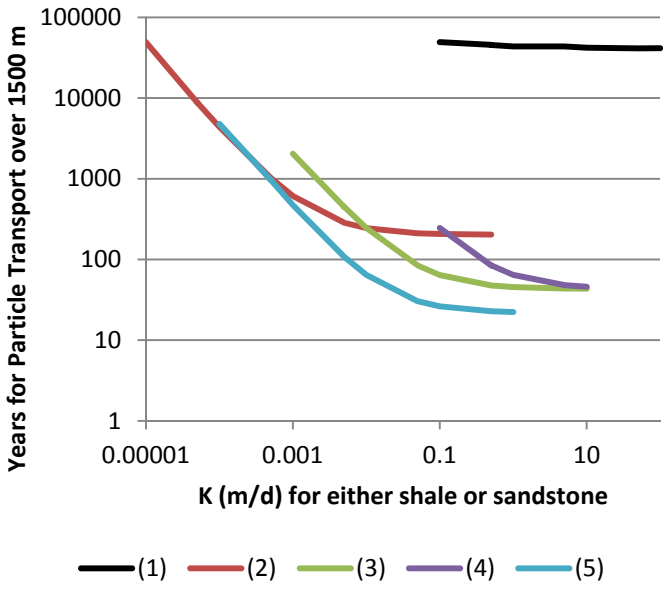

Figure 6: Sensitivity of particle transport time over 1500 m for varying shale and sandstone vertical K. Effective porosity equals 0.1. (1) – varying Kss, Ksh=10-5 m/d, (2) – varying Ksh, Kss= 0.1 m/d, (3) – varying Kss, Ksh = 0.1 m/d, (4): varying Kss, Ksh = 0.01 m/d, and (5): varying Ksh, Kss= 1.0 m/d.

Scenario 2

Vertical transport time through a system including a high-K fault zone was limited primarily by the shale K, presumably because the fault K was one to two orders of magnitude more conductive than that of the surrounding sandstone (Figure 6). Including a fault increased the particle travel rate by about 10 times (compare Figure 8 with Figure 6). The fault K controlled the transport rate for shale K less than 0.01 m/d. A highly conductive fault could transport fluids to the surface in as little as a year for shale K equal to 0.01 m/d (Figure 6).

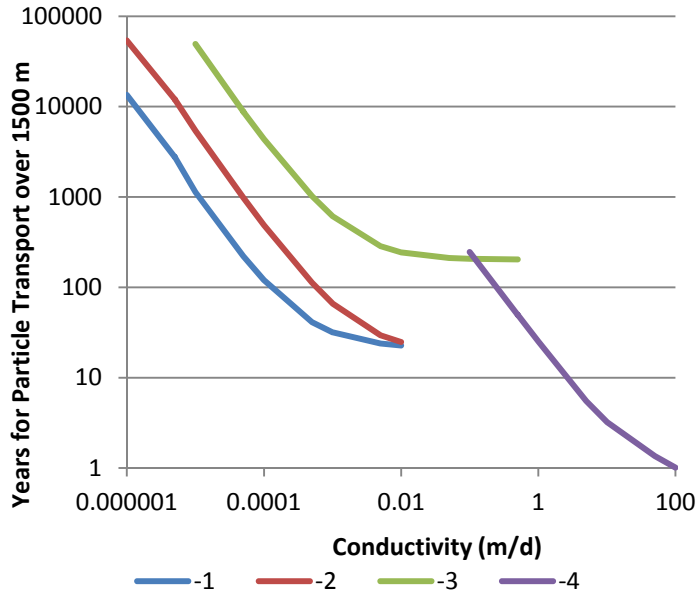

Figure 7: Variability of transport through various scenarios of changing the K for the fault or shale. Effective porosity equals 0.1. (1): Vary Ksh, Kss=0.01 m/d; (2): Varying Ksh, Kss=0.1 m/d; (3), no fault; (4): Varying K fault, Kss=0.1 m/d, Ksh=0.01 m/d. Unless specified, the vertical fault has K=1 m/d for variable shale K.

Scenarios 3 and 4

Scenarios 3 and 4 estimate the time to establish a new equilibrium for scenarios 1 and 2. Equilibrium times would vary by model layer as the changes propagate through the domain, and flux rate for the simulated changes imposed on natural background conditions. The fracking-induced changes cause a significant decrease in the head drop across the shale and the ultimate adjustment of the potentiometric surface to steady state depends on the new shale properties.

The time to equilibrium for one scenario 3 simulation, shale K changing from 10^{-5} to 10^{-2} m/d with sandstone K equal to 0.1 m/d, varied from 5.5 to 6.5 years, depending on model layer (Figure 7). Near the shale (layers 39 and 40), the potentiometric surface increased from 23 to 25 m reflecting the decreased head drop across the shale. One hundred meters higher in layer 20, the head increased about 20 m. These changes reflect the decrease in K across the shale. Simulation of scenario 4, with a fault with K=1 m/d, decreased the time to equilibrium to from 3 to 6 years within the fault zone,

depending on model layer (Figure 7). Faster transport occurred only in areas near the fault. Highly fractured sandstone would allow more vertical transport, but diffused advective flow would also increase so that the base sandstone K would control the overall rate.

The flux across the upper boundary changed within 100 years for scenario 3 from 1.7 to 345 m^3/d, or 0.000008 m/d to 0.0017 m/d. There is little difference in the equilibrium fluxes between scenario 3 and 4 indicating that the fault primarily affects the time to equilibrium rather than the long-term flow rate.

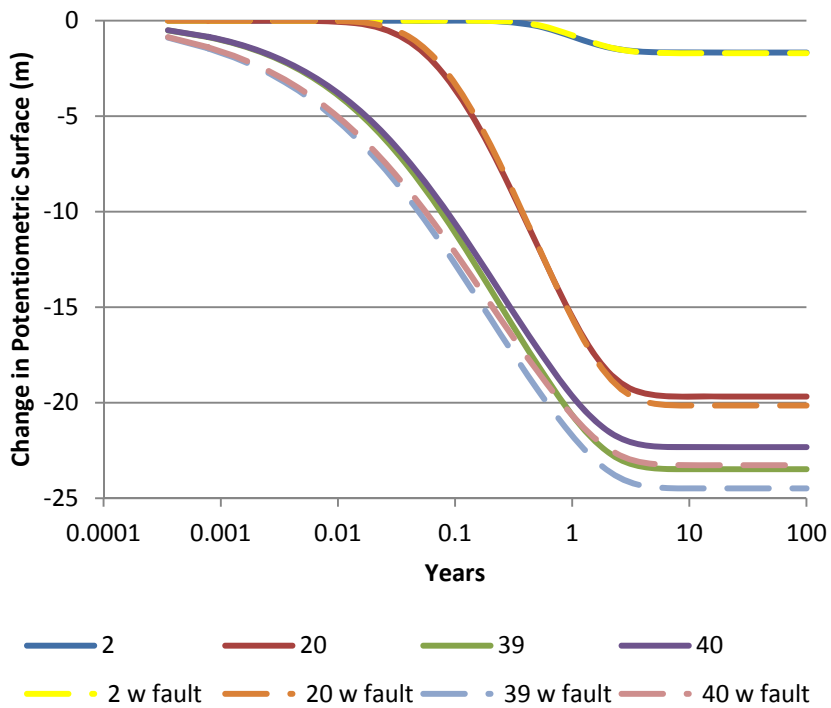

Figure 8: Monitoring well water levels for specified model layers due to fracking of the shale; monitor well in the center of the domain, including in the fault, K of the shale changes from 0.00001 to 0.01 m/d at the beginning of the simulation.

Scenario 5: Simulation of Injection

The injection scenarios simulate 15 million liters entering the domain at the horizontal well and the subsequent potentiometric surface and flux changes throughout. The highest potentiometric surface

increases (highest injection pressure) occurred at the end of injection (Figure 8), with a 2400 m mound at the horizontal well. The peak pressure simulated both decreased but occurred longer after the cessation of injection with distance from the well (Figure 8). The pressure at the well returned to within a meter of pre-injection levels in about 95 days (Figure 8). After injection ceases, the peak pressure simulated further from the well occurs longer from the time of cessation, which indicates there is a pressure divide beyond which fluid continues to flow away from the well bore while within which the fluid flows toward the well bore. The simulated head returned to near pre-injection levels slower with distance from the well (Figure 9), with levels at the edge of the shale (layer 40) and in the near-shale sandstone (layer 39) requiring several hundred days to recover. After recovering from injection, the potentiometric surface above the shale increased in response to flux through the shale adjusting to the change in shale properties (Figure 9), as simulated in scenario three. The scenario required about 6000 days (16 years) for the potentiometric surface to stabilize at new, higher, levels (Figure 9). Removing the fault from the simulation had little effect on the time to stabilization, and is not shown.

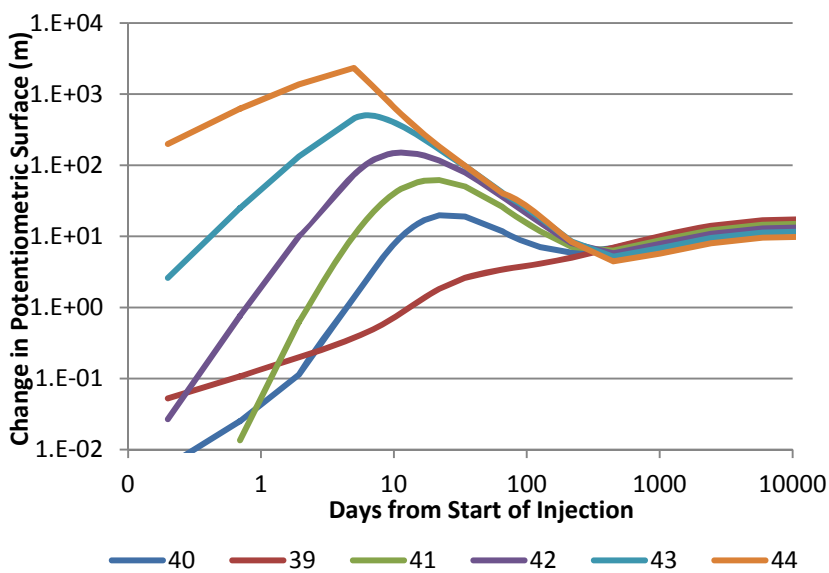

Figure 9: Simulated potentiometric surface changes by layer for specified injection and media properties; Kss=0.01 m/d, Ksh = 0.001 m/d, Kfault = 1 m/d. S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

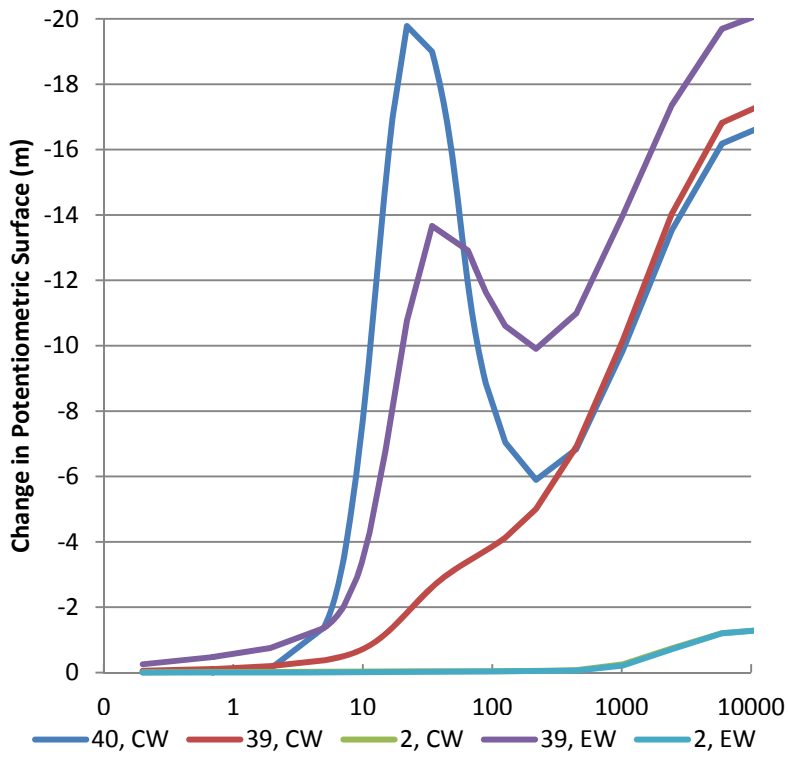

Figure 10: Simulated potentiometric surface changes for layers within the shale and sandstone. CW is center monitoring well and EW is east monitoring well, about 120 m from the centerline. Fault is included. The line for Layer 2, CW plots beneath the line for Layer 2, EW. Kss = 0.01 m/d, Kshale = 0.001 m/d, Kfault=1m/d, S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

Prior to injection, the steady flow for in-situ shale ($K=10^{-5}$ m/d) was generally less than 2 m^3/d and varied little with sandstone K (Figure 5). Once the shale was fractured, the sandstone controlled the flux which ranges from 38 to 135 m^3/d as sandstone K ranges from 0.01 to 0.1 m/d (Figure 10), resulting in particle travel times of 2390 and 616 years, respectively. More conductive shale would allow faster transport (Figure 8). Adding a fault to the scenario with sandstone K equal to 0.01 m/d increased the flux to about 63 m^3/d with 36 m^3/d through the fault (Figure 10) and decreased the particle travel time to 31 from 2390 years. The fault properties control the particle travel time, especially if the fault K is two or more orders of magnitude higher than the sandstone.

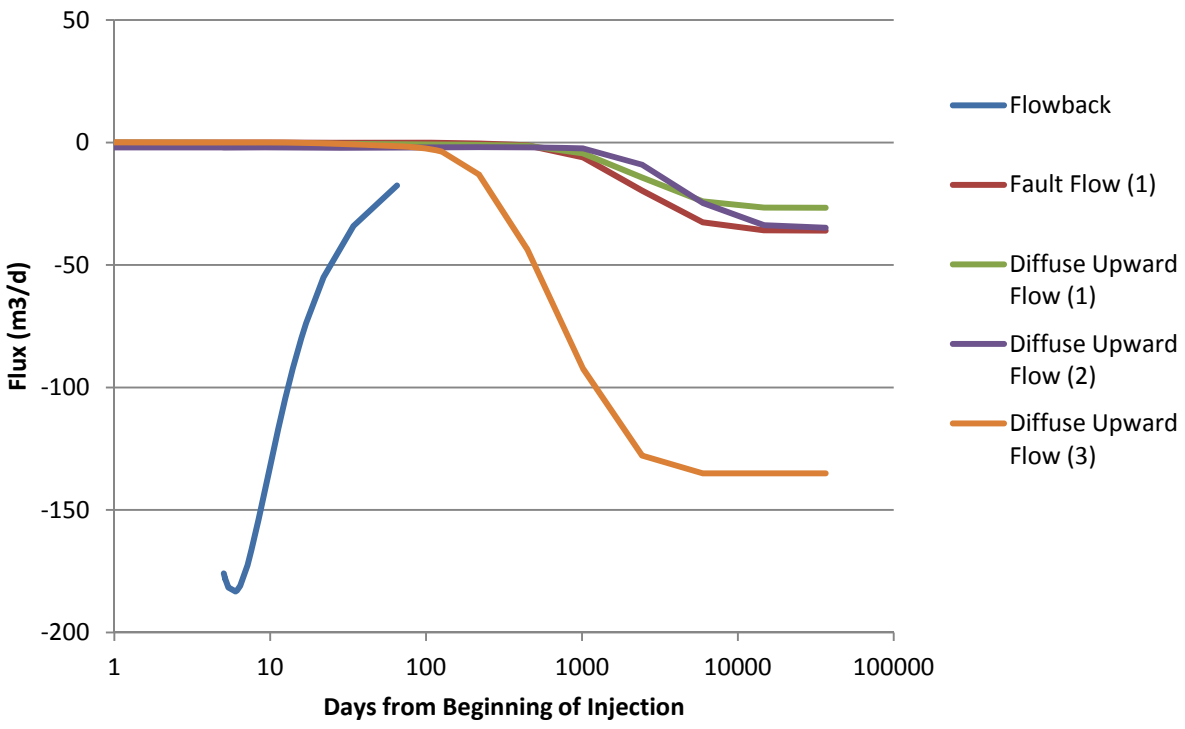

Figure 11: Various fluxes for three separate scenarios. Flowback is the same for all scenarios. (1): Kss=0.01 m/d, Kshale = 0.001 m/d, Fault K = 1 m/d; (2): Kss = 0.01 m/d, Kshale = 0.001 m/d, no fault; (3) Kss= 0.1 m/d, Kshale = 0.001 m/d, no fault.

Simulated flowback varied little with shale K because it had been calibrated to be 20 percent of the injection volume. A lower storage coefficient or higher K would allow the injected fluid to move further from the well, which would lead to less flowback. Lower K would also lead to higher injection pressure which in turn would fracture the shale more.

Vertical flux through the overall section with a fault varies significantly with time, due to the adjustments in potentiometric surface. One day after injection, vertical flux exceeds significantly the pre-injection flux about 200 m above the shale (Figure 11). After 600 days, the vertical flux near the shale is about 68 m^3/d and in layer 2 about 58 m^3/d; it approaches steady state through all sections after 100 years with flux equaling about 62.6 m^3/d. The 100-year steady flux is about 61.5 m^3/d higher than the pre-injection flux because of the changed shale properties.

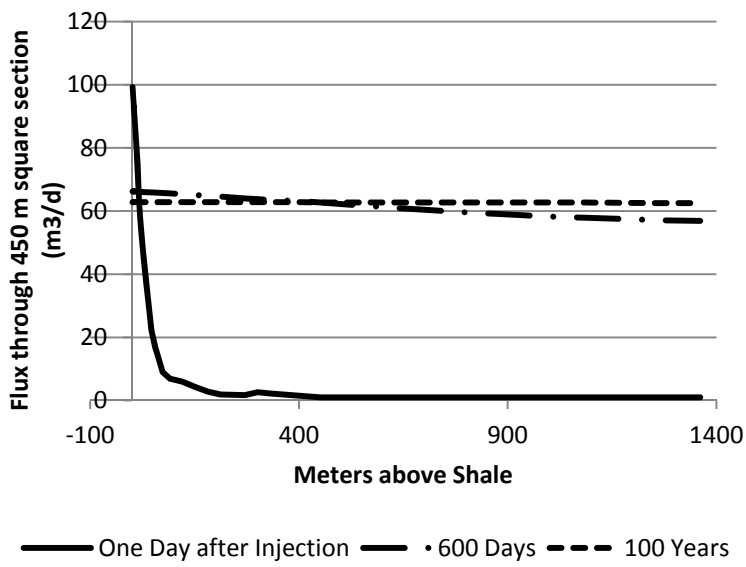

Figure 12: Upward flux across the domain section as a function of distance above the top of the shale layer. Cross section is 202,500 m^2.

Discussion

The interpretative modeling completed herein has revealed several facts about fracking. First, MODFLOW can be coded to adequately simulate fracking. Simulated pressures are high, but velocities even near the well do not violate the assumptions for Darcian flow. Second, injection for five days causes extremely high pressure within the shale that decreases with distance from the well. The time to maximum pressure away from the well lags the time of maximum pressure at the well. The pressure drops back to close to its pre-injection level at the well within 90 days, indicating the injection affects the flow for significantly longer periods than just during the fracking operation. Although the times may vary based on media properties, the difference would be at most a month or so, based on the various combinations of properties simulated. The system transitions within six years due to changes in the shale properties. The same order of magnitude would apply to changes in shale properties from less to more conductive. The equilibrium transport rate would transition from a system requiring thousands of years to one requiring hundreds of years or less within less than ten years.

Third, most of the injected water in the simulation flows vertically rather than horizontally through the shale. This reflects the higher sandstone K 20 m above the well and the no flow boundary within 225 m laterally from the well, which emulates in-situ shale properties that would manifest at some distance in the shale.

Fourth, the interpretative model accurately and realistically simulates long-term steady state flow conditions, with an upward flow that would advect whatever conservative constituents exist at depth. Using low, unfractured K values, the transport simulation may correspond with advective transport over geologic time although there are conditions for which it would occur much more quickly (Figure 5). If the shale K is 0.01 m/d, transport could occur on the order of a few hundreds of years. Faults through the overburden could speed the transport time considerably. Reasonable scenarios presented herein suggest the travel time could be decreased further by an order of magnitude.

Fifth, fracking increases the shale K by several orders of magnitude. The regional hydrogeology changes due to the increased K. Vertical flow could change over broad areas if the expected density of wells in the Marcellus shale region (NYSDEC 2011) actually occurs.

Sixth, fault fracture zones coming close to contacting the newly-fractured shale could allow contaminants to reach surface areas in tens of years. Faults can decrease the simulated particle travel time several orders of magnitude.

Conclusion

Fracking can release fluids and contaminants from the shale either by changing the shale hydrogeology or simply by the injected fluid forcing other fluids out of the shale. The complexities of contaminant transport from hydraulically fractured shale to near-surface aquifers render estimates uncertain, but a range of interpretative simulations suggest that transport times could be decreased from geologic time

scales to as few as tens of years. Preferential flow through fractures could further decrease the travel times to as little as just a few years.

There is no data to verify either the pre- or post-fracking properties of the shale. The evidence for potential vertical contaminant flow is strong, but there are also almost no monitoring systems that would detect contaminant transport as considered herein. Several improvements could be made.

- Prior to hydraulic fracturing operations, the subsurface should be mapped for the presence of faults and measurement of their properties
- A reasonable setback distance from the fracking to the faults should be established. The setback distance should be based on a reasonable risk analysis of fracking increasing the pressures within the fault.
- The properties of the shale should be verified, post-fracking, to assess how the hydrogeology will change.
- A system of deep and shallow monitoring wells and piezometers should be established in areas expecting significant development, before that development begins (Williams 2010).

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Appendix C

Review of NYSERDA Commissioned Review of Myers Comments on the 2009 DSGEIS

Prepared by: Tom Myers

11/30/11

Introduction

The New York State Energy and Resource Development Agency (NYSERDA) commission Alpha Geosciences (Alpha) to complete a review of the comments I had prepared for the 2009 Draft Supplemental Generic Environmental Impact State (DSGEIS). This report replies to some of those review comments. Throughout, I refer to the review as "Alpha".

General Points

Alpha divided my comments into various subsets for their response, but they rely very much on several points throughout their response. One is their perception of there being no hydraulic connection between groundwater at depth, in the Marcellus shale, and the near-surface aquifers; they also dismiss the analysis from ICF (2009) on the same basis, even though they have no data with which to dismiss the argument. Their second line of reasoning is the results or conclusions from the 2004 EPA study of coal bed methane fracking.

Alpha rejects the suggestion that a water balance for the project area or subareas "would not serve the purpose of the SGEIS" (Alpha, at 4). They provide no reason for this conclusion, but also state that a "water balance clearly is site-specific" (Id.). A water balance can be useful for any size study area or portion of the study area. A water balance for the overall study area would help to understand the total volume of water involved in fracking; a similar argument can be made for a watershed – a water balance for the groundwater would help to understand whether the water amounts used for fracking is a substantial portion of the local water balance.

Alpha partially rejects my suggestion that a better description of the area's hydrogeology is needed by quoting my statement that "the Marcellus Shale is 'notoriously heterogeneous'" (Alpha, at 4). The request for a better description pertains to the overall area, not specifically the Marcellus shale. Additionally, the statement supports the concept that reported permeability values for the shale may not be representative and that broader scale description are required.

Hydraulic Connection between Shale and Surface

Alpha argues that the "target shales exist as an isolated system from the overlying fresh water-bearing units" (Alpha, at 4). "Isolated" overstates the case even for natural conditions, although the connection may be limited, as I accepted in 2009. Alpha claims that the "shales … are not part of, and are not connected to, the regional hydrogeological systems. Their baseline geologic evidence that fluid

migration to overlying fresh water aquifers is improbable includes studies that show the Marcellus shale has remained isolated from overlying formations for millions of years" (Alpha, at 5). Alpha does not directly provide citations for these "studies", but in the next sentence references the "facts that these units are 'overpressured' and that natural gas and saline water has remained trapped … for millions of years" (Id.) to two industry studies and the GEIS. This all ignores the science, cited in Myers (in review) of the upward movement and artesian pressure, observed during geothermal exploration, in formations above the shale. The salt in the shale may be the source of the salt in overlying formations, with the upward movement of salt balanced by the downward movement of freshwater recharge. This balance could be substantially upset by the changes wrought by fracking on the shale.

The "overpressuring" of the shale does not prove that the shale itself is isolated. Overpressuring is due to the gas being contained in the low permeability, very small pore spaces of the shale. Once fracked, the overpressuring may provide an initial source for water to flow into the formations above the shale.

The isolation argument is invoked again, by Alpha, at 11&12, 20, and 33.

My discussion relied and continues to rely for the 2011 rDSGEIS on the fact that fracking will change those conditions, changing the shale from an almost impervious aquitard into a low-conductivity formation; the previously isolated formation water will no longer be "isolated" because fracking fluid injection will push some into surrounding formations. The "overpressuring" in the shale may suggest that the shale itself is isolated at least in places. Myers' (2009 and in review) argument relies on the connection in the formation above the shale. Once fracked, the shale will have a much higher permeability so that fluids in the shale can move into surrounding formations within which the general groundwater flow will control.

Alpha refers to the fact that shallow water wells may be hydrofractured as "additional evidence that natural fractures and structures are not necessarily transmissive" (Alpha, at 4 and 37). This is a comparison of "apples and oranges". Hydrofracturing water wells may be done to increase their yield when screened in low-transmissivity formations; fracking water wells is done to increase the well yield from a few gallons per minute. The transmissivity of unfracked shale is orders of magnitude less than that in the formations in which a water well may have been screened. The cause for fracking in water wells differs from the cause for fracking a gas well; the comparison is irrelevant and proves nothing about the isolated nature of shale.

A further reliance on "overpressuring" is demonstrated (Alpha, at 5) where Alpha notes that eight research wells in the Marcellus shale had pressure gradients of 0.46 to 0.51 psia/ft when hydrostatic pressure is 0.433 psia/ft. That waters remain contained in the shale even with this overpressuring demonstrates their isolation. Once fracking hydraulically connects the shale with the overlying formations, the overpressuring is a source of pressure that would cause an upward gradient. The pressure would likely dissipate with time, but it would also cause an upward gradient after fracking.

Alpha indicates that my "hypothetical pathway … to ground water is along faults and fractures that intersect the Marcellus or induced fractures that extend beyond the target formation" (Alpha, at 5). This mischaracterizes the argument in two ways. First, it ignores the potential flow through the bulk media, through the primary porosity of the formations; this pathway would be slower, but flow is possible if there is a connection (Myers, in review) with the newly fractured shale. Myers (in review) found this flow to require from 100s to 1000s of years for contaminant transport. Second, natural faults and fractures do not have to "intersect" the shale, just reach its edge. Fluids within the shale would access the natural fractures above the shale, once fracked; the overpressuring would provide an added gradient for flow from the shale to surrounding formations, once fracking releases the fluids.

Alpha's second point is correct; out-of-formation fractures would provide an additional pathway. Although Alpha continues to suggest that out-of-formation fracking is rare, in their view, more current evidence is that it occurs frequently and extends as much as 2000 feet above the target formation (Fischer 2010); Alpha even references a personal communication from Fisher (Alpha, at 24) to recommend that the "SGEIS acknowledge that hydrofracturing has been shown to induce fractures beyond the target formation" (Id.). It appears that Alpha is not familiar with up to date literature or science.

Alpha rejects the "suggestion of 'head level maps'" that I had suggested in 2009 based on their rejection of the concept of saturated conditions from the "top of the target zone to the land surface" (Alpha, at 20). If there is no connection, groundwater levels will show nothing. They also note the isolation argument (at 20, 21) to reject the need for head level maps. Head level maps as recommended by Myers (2009) would confirm or deny the presence of upward head gradients in the formations above the shale. Once released by fracking, contaminants could advect along the flow paths which would be delineated by the hydraulic gradient. Although the fracking itself will change the gradient and potentially increase the potential upward flow, mapping the groundwater levels would assist the NYSDEC in determining where transport is possible. Alpha's recommendation is to basically ignore science and ignore the possibility of upward flow. Alpha replied to my comment suggesting that the rDSGEIS discuss properties resulting from fracking by discussing the direction that fractures would take in the shale (Alpha, at 15). My comments indicated that the rDSGEIS should include hydrogeologic properties, therefore Alphas reply was not responsive to the comment. Alpha's response that my "argument that the fractures will extend to and connect overlying fractures or paleofractures contradicts rock mechanics principles and field observations" is countered by the recent data in Fisher (2010) showing out-of-formation fracking. Alpha is unclear and provides no references as to how the comments contradict "rock mechanics principles".

I had also recommended that the NYSDEC require the industry to monitor post fracking shale properties. Alpha states that "[f]racture monitoring is required by the Proposed Supplementary Permit Conditions … (#33 and #34)" (Alpha at 16). That is incorrect; those permit conditions require the driller report on recorded operations during fracking, including pressure and the amount of injected, but that is not the same thing as doing post-frack monitoring, which could include microseismic surveys or core sampling. They also suggest that "[f]racture monitoring also can be evaluated on a well-specific basis using the

same criteria as the requirement to collect core samples and well logs" (Alpha, at 16). Those requirements are for pre-fracking conditions, not post-fracking.

Myers' Groundwater Modeling and ICF Analytical Modeling

I prepared (Myers 2009) an interpretative numerical groundwater model to consider whether and over what time frame flow could occur from the shale to freshwater aquifers. The "theory supporting Myers' model" is NOT from Hill and Tiedeman (2007) (Alpha, at 23). The reference is to the concept of "interpretative" modeling as opposed to a calibrated, predictive model. "Myers acknowledges that his model is not calibrated and cannot be used for predictive purposes" (Alpha, at 12). An interpretative model is not used for prediction, so Alpha's attack on the model is an attack here is irrelevant. The model does assume that the interburden between the ground surface and top of the shale is saturated, but not through the "isolated shale gas formations" (Id.). Again, the modeling is of the interburden and the shale, once it is fracked to its edge or beyond, is a boundary or a source of both fluids and contaminants. Or, flow through the shale is estimated based on its extremely low in-situ conductivity.

The numerical model I used in 2009 was not "to support [my] opinion" (Id.) but to test my conceptualization as to whether the flow was possible and under what conditions. Alpha criticizes the fact the model "oversimplifies ground water flow and transport". All groundwater models simplify flow; simple applications of Darcy's law are the most oversimplified analyses. The addition of secondary permeability, or fracture flow, to a contaminant transport analysis usually increases the rate that contaminants move, thus my estimated times should be low.

Alpha asserts that my "offered alternate model is not technically defensible" apparently based on their perceived lack of a hydraulic connection. They state that an assumption of a hydraulic connection "contradicts decades of hydrofracturing data and experience in the U.S." (Alpha, at 11) without referencing or outlining the data in support of their contention. They also claim that my analysis is based on "the entire bedrock stratigraphic column [being] highly fractured" (Alpha, at 12). This statement does not reflect the analysis in Myers (2009), for reasons noted above - the conductivity values used for the formations between the shale and surface were based on observed primary conductivity values (Anderson Woessner 1992), not fractured values.

ICF's flow equations are correct (Alpha at 11), but the problem is how they were parameterized and time frame they were applied over. As Myers (2009) discussed, the relevant gradient is not from the well to the aquifers, but from the well to just beyond the influence of the spreading injected fracking fluid, the point at which the background pressure has not changed. Also, the conductivity parameters for the formations between the shale and the aquifers do not reflect fractures, unless specifically parameterized as such. The parameters reflect standard textbook bulk conductivity values for sandstone.

Vertical Contaminant Transport

I had argued that "natural gradients" would allow vertical contaminant transport of frack fluid through advection. Alpha claims that "Engelder refutes that injected frac water would migrate vertically upward

in his slide-presentation review of others" (Alpha, at 24). Aside from the confusing phrase, "slide-presentation review of others", this line of reasoning cannot be correct because frack fluid is lighter than the high-TDS brine found in the shale; buoyancy due to frack fluid being lighter than brine would enhance its upward movement. The movement of high-TDS formation water could be inhibited by its denser nature, but the point is that upward hydraulic gradients cause the flow. The overpressuring discussed above is proof of these upward gradients and suggestive that fracking would release some of this pressure into the formations lying above.

Engelder's "principle of viscosity" (Id.) may apply "to ground water as well as gases", but the fact that low viscosity gases have been contained from vertical migration for millions of years does not mean that fracking will not release contaminants that could migrate upward much quicker. The relevant "containment" is provided in the shale and has nothing to do with the properties of overlying formations. Shale has contained gas for millions of years; fracking will cause that gas to be released in 30 to 50 years (the length of time most wells will produce). This can only occur if the properties that contain the gas will vastly change.

Leaks from Well Bores

The DSGEIS had implied that leaks do not occur from properly-constructed wells, but did not specify how often wells are found to not be properly constructed, and I requested (Myers 2009) that they provide an estimate of the times the wells are not properly constructed. Alpha responded with a quote from an industry source that estimated risk from failures to properly constructed wells is less than one in 50 million (Alpha, at 32). Alpha should have included the entire paragraph from which they selectively chose their quote, because it indicates the wells considered are class II injection wells and are properly constructed. Fracking wells experience a much higher, although much shorter, pressure during operations. They also should realize that the comment had to do with wells that are improperly constructed, because most failures, those that have allowed gas into groundwater, have resulted from improperly constructed wells.

Alpha also protests too much when they discuss my examples of gas in water wells (Alpha, at 33, 34). Incidents not related specifically to fracking are relevant because they show that the gas does move long distances through the groundwater, regardless of the source. Coal bed methane development relies on the gas moving through the groundwater, in coal seams, to the production wells; those production wells commonly pump as much water as do water wells, so, if gas is present to move to the water wells, the conceptual model for flow to water wells is similar. The point has to do with gas moving through aquifers due to any source – direct from the shale or a leak from the well bore.

Comparison to CBM Wells

Alpha used the conclusion to the EPA's 2004 CBM study, that fracking in coal seams poses little or no threat to underground sources of drinking water (Alpha, at 20) to support their conclusion that I had ignored relevant data (EPA's study) and that my arguments were fallacious because CBM wells are a much higher risk. They also state that "[c]oalbed hydrofracturing events approximate conditions where shale hydrofracturing is performed closest to ground water resources" (Id.). This is simply not true, and

it directly contradicts the conditions that the EPA put on their conclusion. EPA relied on the nature of CBM wells for their conclusion. "Although potentially hazardous chemicals may be introduced into USDWs when fracturing fluids are injected into coal seams that lie within USDWs, the risk posed to USDWs by introduction of these chemicals is **reduced significantly by groundwater production and injected fluid recovery**, combined with the mitigating effects of dilution and dispersion, adsorption, and potentially biodegradation" (EPA, 2004, at 7-5, emphasis added).

In fracked shale, there is no intentional "injected fluid recovery" brought about by pumping the injection wells, as in CBM wells. CBM wells pump water toward the gas well; this pumping decreases the hydrostatic pressure which releases the gas from the coal. Water and contaminants in the coal seam flows toward the CBM well. If there were contaminants in the coal, they would be drawn toward the CBM well.

Fracking in a coal seam would require much less pressure as well which would cause less out-of-formation fractures, which would limit the chance for out-of-formation fractures to occur. Additionally, EPA relies on the "high stress contrast between adjacent geologic strata" as a barrier to fracture propagation. The fact the coal is softer and the seams are much shallower and require much less fracking pressure helps to limit the fractures to the coal, much in contrast to shale seams (Fisher, 2010).

Finally, although the EPA's reasoning is reasonable, their methodology for concluding there has been no contamination is suspect; they only considered reported cases of contamination rather than relying on monitoring data. Fracking fluids in water wells near coal seams would be reported only if someone detects a problem. There have been cases of methane reaching water wells in the coal seams, but methane is obvious as it bubbles coming from the faucet.

Alpha claims that "Myers fails to address the historical data presented by ICF (2009, p. 22)" (Alpha at 19). ICF (2009, p 22) does not actually present data, contrary to Alpha's allegation. GWPC (1998), the source of ICF's "data", presents the results of a survey to which officials from states with over 10,000 coal-bed methane wells had responded they had never found groundwater contamination. However, contrary to Alpha's allegation, GWPC did not analyze 10,000 wells' worth of data. GWPC does not present monitoring data as proof, they present survey data from agency personnel claiming there has been no reported contamination. There is no indication whether the agencies ever looked for contamination beyond the claims of well owners. ICF also notes that coal seams may be used as aquifers, but did not indicate how many of the coal seams being developed by the CBM wells in the states replied to by the agency personnel were also aquifers.

Alpha truly mixes apples and oranges by using studies of CBM development, including fracking, to conclude that shale-gas development poses no threat to groundwater.

General Hydrogeology

Alpha's response to comments regarding aquifer depletion is a stretch to show how they actually disagree with my comments. Specifically, my comments about failures to regulate are replied to by stating the various commissions must permit the withdrawal – the problem is that there are really no

specifics provided about how the decision to permit would be granted. The DSGEIS did not specify what standard had to be met, beyond simple reporting, to be granted a permit.

Mitigating Surface Water Impacts

Alpha goes out of its way to find something to criticize in its review of my general surface water comments (Alpha, at 44, 45). My comments were generally qualitative and Alpha's responses are generally not substantial enough to require a reply here.

In Alpha section 4.2, regarding the use of the natural flow regime method, Alpha states that I was incorrect in claiming the NYSDEC would not require its use (Alpha, at 48). The 2011 rDSGEIS states clearly that it is NYSDEC's intent to require use of the NFRM, but the 2009 DSGEIS only states that it is "preferred", not required (2009 DSGEIS, at 7-3).

Alpha responds in detail to my comments regarding the Delaware and Susquehanna River Basin Commissions' methods (Alpha at 46, 47), even though they acknowledge the dSGEIS would require the NFRM. Because the rDSGEIS states the NFRM will be used throughout the project area, there is little reason to reply further to Alpha's comments at this point.

Ultimately, Alpha adapts many of my recommendations regarding surface water flow (Alpha, at 50, 51). They do not specifically endorse the recommendation to minimize the effect on aquatic habitats (outlined at Alpha, p. 47), the RDSGEIS does adapt a recommendation for using the Q60 or Q75 flow by month, which by month is better than my original recommendation.

Setbacks

Alpha discusses vertical setbacks along with my comments on monitoring and the need for water level mapping (Alpha, section 3.1). Much of their response relies on their perceived lack of hydraulic connection among formations, which has been discussed above.

Regarding horizontal setbacks, I had suggested that the recommended values are not based on any data or analysis of their effectiveness. Alpha simply rejects this without providing any reference, data, or results. "Myers assumes the setbacks proposed in the dSGEIS are not based on analysis; however, the setbacks are supported by practical application, experience, and historical analyses" (Alpha, at 43). Alpha repeats this sentence twice, verbatim, on the same page. When stating something as being based on analyses, it is customary scientific practice to cite the references to these analyses, something Alpha has failed to do. Alpha also suggests the "dSGEIS reference SEQRA, NYSDOH, NYC Watershed Rules and Regulations, the Clean Water Protection Act, and public water protection rules from other states" (Id.). Alpha does not indicate where in the dSGEIS these references are made, not indicates that the references include any analysis. Referencing others' rules without analyzing their effectiveness is not a scientific justification for specifying a setback. My statements are not that the setbacks are wrong, but that it is unknown whether they are effective. My recommendations may be larger than those in the dSGEIS, but they are designed to be protective to encourage a site specific analsis.

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Attachment 3

Glenn Miller, Ph.D.

Review of the

Revised Draft
Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program
Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

Prepared for:
Natural Resources Defense Council
New York, New York

Prepared by
Glenn C. Miller, Ph.D.
Reno, NV

January 6, 2012

This document represents a review of the Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) regarding proposals to develop natural gas wells using high-volume hydraulic fracturing in New York. I have specifically examined some of the chemical and toxicological issues, particularly related to the fracturing additives used, and the management of the severely contaminated flowback/produced brines. The RDSGEIS, in general, is an improved document compared to the previous draft of the potential environmental impact of the very large number of gas wells being proposed in much of New York. However, several key potentially significant adverse impacts remain inadequately addressed.

The following comments should be considered.

A. The water that flows back immediately following hydraulic fracturing is heavily contaminated (flowback), primarily with the Marcellus formation contaminants, and represents the most problematic chemical contamination potential, due to the large volumes of contaminated water generated. The brines that will be produced during gas production[1] will have higher concentrations of naturally occurring contaminants than flowback water (although lower volumes) and similarly represent a serious chemical contamination potential.

The RDSGEIS recognizes these problems and goes a long way towards evaluation and management of the contaminants; however, it still does not present a comprehensive wastewater management and disposal plan that will handle the anticipated large volumes of heavily contaminated wastewater. Further efforts are required to properly understand the contaminants in the flowback water, and develop management and disposal solutions.

Four problematic components of the flowback water and produced brines are present, including: (1) salts, other inorganic constituents, and metals and metalloids; (2) the radioactive component (NORM); (3) organic substances (from the hydrocarbon formation) and (4) hydraulic fracturing chemical additives.

1. ***Salts, other inorganic constituents, metals and metalloids in the formation water that are brought to the surface both as flowback and as production brines*:** The largest mass component of the formation water is salts and other inorganic constituents. The concentration of these constituents varies widely, as does their toxicity. Because the flowback is proposed to be collected and temporarily stored in closed systems, disposal of these large volumes of water is the largest problem with its management. The RDSGEIS discusses the problems with management of this water, and in

[1] The terms produced brine, production brine, produced water, and produced water brine are used interchangeably throughout these comments for formation water that is produced up the well.

particular the discharge of high total dissolved solids (TDS) water into receiving waters (see, for example pages 7-63), and stipulates that flowback produced water and brines will need to be regulated as industrial wastewater.

Table 5-10 of the RDSGEIS shows that produced waters (from Pennsylvania and West Virginia) containing the formation water are variable in chemical composition, but include not only simple salts (e.g., sodium, potassium, chloride, bromide, sulfate, fluoride, etc.) but also a variety of metals with varying frequency (cadmium, mercury, cobalt, nickel) and metalloids (arsenic, selenium, boron). Some of the constituent concentrations are very high, particularly sodium chloride, which has a mean concentration of over 10% by weight. Some samples had over 30% by weight simple salts plus other contaminants. The extreme contamination of these wastewaters and the high variability of contaminant levels make these waters complicated for treatment and potential reuse, as well as for tracking and disposal. If improperly managed and released to surface or groundwater, severe contamination is a reasonably foreseeable outcome. In particular, if this contaminated water intercepts domestic groundwater sources, the potential exists to permanently damage aquifers as current and future domestic water supplies.

While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of treatment and disposal alternatives, the RDSGEIS does not sufficiently analyze the environmental or human health impacts associated with any of these treatment and disposal options. Further, the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state, where regulations may be less stringent, due to the lack of treatment capacity for these contaminated waters in New York.

2. ***Radioactive Substances (NORM):*** The RDSGEIS also recognizes the issues associated with management of NORM that comes to the surface either in the flowback or the production brines. However, similar to the salt problem discussed above, it does not explicitly indicate how wastes contaminated with NORM will be regulated and disposed.

   Examples of NORM concentrations in flowback are presented in Table 5-24, and in produced brines in Appendix 13. As expected, the NORM present in the flowback is somewhat lower than in the brines, due to dilutions when fresh water is used for the primary fracturing fluids. Less dilution would be expected if the flowback is reused as a portion of the fracturing fluid for another well.

Only three produced brine samples are shown in Appendix 14, but the level of radioactivity as gross alpha is very high, from about 18,000 pCi /L to 123,000 pCi/L. The standard for safe drinking water is 15 pCi/L (gross alpha).

The RDSGEIS does not propose a disposal solution for residual NORM, if it is separated from the produced water and the flowback water. Dilution of the brines to a drinking standard of 15 pCi/L (gross alpha) will require 1000x to 10,000x dilutions, and is unlikely to be acceptable in any jurisdiction, particularly when the components that are causing the radioactivity are not specified. While some mention of regulatory oversight is made in the RDSGEIS, there are no explicit indications of how these waters will be regulated or managed. The RDSGEIS does not propose a technically sound or viable solution for disposing of these radioactive materials. The RDSGEIS has not examined options such as evaporation-crystallization treatment or chemical precipitation. These processes will produce a very large tonnage of salts containing radioactive and metal waste. The lack of a thorough treatment and disposal analysis presents a serious problem when assessing the risk and potentially significant adverse impacts of these substances. There is effectively no analysis of how these materials will be disposed, other than a general (potential) suggestion that new licensing may be required.

For an adequate environmental analysis, it is also critical to identify the sources of the gross alpha radiation. Gross alpha radiation is defined by the U.S. EPA (40 CFR Parts 9, 141, and 142 [National Primary Drinking Water Regulations; Radionuclides; Final Rule]) as the total amount of alpha radiation minus the alpha radiation coming from uranium and radon. Table 2.3 of the RDSGEIS, which specifies the primary drinking water standards, is unclear as to how New York regulates radioactivity, other than to indicate that it will limit "alpha particles" to 15 pCi/L in drinking water, but does not indicate if that includes uranium. For the three samples of groundwater indicated in Appendix 13, only a small fraction of the components of the gross alpha have been identified, with the largest component being ^{226}Ra. For the three samples provided in Appendix 13, the individual gross alpha contributors can be summed to provide only 14-24% of the gross alpha in the water samples. The RDSGEIS does not identify the source of the remaining 76%+ alpha radiation; this omission constitutes a major flaw in the radioactive waste treatment and disposal analysis.

While it may be difficult to get an exact mass balance, accounting for less than 25% of the alpha radioactivity is insufficient.

It is unclear whether the data in Appendix 13 were based on the EPA gross alpha radiation definition, but the implications are substantial. If the EPA gross alpha radiation definition is used (which is probably the case), some other source of the alpha radiation will be present (e.g., polonium) as was

observed in the Florida phosphate industry (Burnett, et al., 1988). Verifying radioactive waste constituents is particularly important when assessing radioactive waste risk and to develop viable treatment and disposal options. Radioactive materials will also precipitate as scale in equipment; therefore, verifying radioactive waste constituents is also important for determining the radioactive risk as pipes are disassembled when cleaning is needed, or when the wells are disassembled when gas production ceases. If the source of the excess alpha radiation is polonium, the residual radioactivity from water treatment or scale management will potentially be more expensive to manage safely. The RDSGEIS has not analyzed the polonium risk, or treatment and disposal options for radioactive waste containing polonium.

While the U.S. does not have a polonium 210 standard, both Canada and the European Union do (see accompanying comments of Dr. Ralph Seiler), and it is lower or similar to the U.S. radium standard (5 pCi/L). Polonium is soluble in water under reducing conditions, and should be assumed to contribute to the alpha emission from the formation water, unless NYSDEC can rule out the risk. Polonium's risk contribution, however, is not currently analyzed in the RDSGEIS, and is a critical data gap in the NORM analysis. Polonium is a strong alpha emitter, but most importantly, treatment/management of these waters for disposal should require knowledge of the composition of the alpha emitting NORM component. Only then can appropriate methods for treatment and disposal be developed.

An additional component of the naturally occurring radioactivity is radon, a gaseous odorless radioactive element that is responsible for approximately 21,000 deaths from lung cancer each year (ATSDR, 2012), and is second only to cigarette smoking for causing this disease. Southern New York is already recognized as a region where elevated radon (>4 pCi/L) is common. Adding radon to households either from improperly vented gas utilizing appliances or through water systems that have been contaminated with natural gas leaks in groundwater supplies presents an additional risk factor for radon.

Data on radon in natural gas from the Marcellus Shale formation is very scant, and the RDSGEIS does not contain a sufficient amount of data to verify the maximum concentrations of radon expected in Marcellus Shale gas, or any other natural gas that may be developed under the proposed scope of the SGEIS. The amount of radon in natural gas is a critical measurement that should be made, to examine the incremental risk of radon exposure in homes and places of business that use natural gas or well water that could experience higher radon content as Marcellus and other shale gases are produced in NYS. While normal natural gas use in properly ventilated burners is unlikely to contribute to radon concentrations in closed spaces (see accompanying Seiler report), poorly vented areas may result in increased radon concentrations, and certain scenarios (e.g., high use of natural gas for industrial applications, restaurants that use gas burners)

should be subject to risk assessment. The risk of radon exposure from burning natural gas in poorly ventilated areas is likely to be greatest in indoor areas that already have elevated radon exposure levels.

An additional risk is when natural gas from a well leaks into an aquifer used as a well water source. Depending on concentrations of radon in the water, and the use of that water, radon levels can potentially be elevated in homes. This is a separate risk than from burning natural gas, but it is reasonable to develop scenarios where highly radon-contaminated gas moves through the soil profile and into homes. However, there are only scant radon data that can provide a basis for estimating those risks.

Recommendation 1. The SGEIS should clearly identify treatment and disposal options for flowback and wastewater, analyze the range of treatment and disposal alternatives, and propose the best technology and best practices for handling this waste. These technologies and practices should be included in the SGEIS as a mitigation measure, and codified in the NYCRR. The SGEIS treatment and disposal options for flowback and wastewater analysis should include a detailed examination of the waste constituents including, at a minimum: salts and inorganic constituents; NORM; metals and metalloids; organic substances (from the hydrocarbon formation); and fracture treatment additives.

Recommendation 2. The SGEIS should examine the existing wastewater treatment capacity in NYS, compared to the potential volume and composition of wastewater that will be generated by the proposed development, and make specific recommendations to ensure sufficient waste handling capacity exists before authorizing the proposed development. If waste will be transported to other states, the SGEIS should examine the impacts of that waste handling option as well.

Recommendation 3. The components of the gross alpha radioactivity should be identified in the RDSGEIS, and mitigation measures should be proposed to address radioactivity risk. The RDSGEIS does not identify 76%+ of the gross alpha radioactivity. The specific definition of gross alpha radioactivity should also be stated, or the EPA definition should be used.

Recommendation 4. The RDSGEIS should determine whether polonium is a significant component of alpha emission in formation waters, and polonium-contaminated wastewater should be regulated/managed appropriately to limit its discharge to surface or groundwater, as should all of the individual components of NORM.

Recommendation 5. Specific treatment methods to remove radioactive constituents from flowback and produced water need to be identified. If the radioactive constituents are removed from wastewater, management methods and disposal sites for the residual radioactive wastes should be identified. (See further discussion below.)

Recommendation 6. Additional radon measurements are needed to determine the range of concentrations of radon expected in Marcellus Shale gas or any other gas that may be developed under the proposed scope of the SGEIS. Gas measurement should be made at the wellhead, where natural gas is being used, including homes, businesses that use large amounts of natural gas, and in areas where natural gas leaks have been found. The SGEIS should include radon testing requirements as a mitigation measure, and this requirement should also be codified in the NYCRR.

3. ***Hydrocarbons present in the formation water:*** Hydrocarbons present in the flowback and produced water are characteristic of fuel hydrocarbons, and are represented by (a) compounds that, in some cases, are carcinogenic (e.g., benzene, benzo(a)pyrene); (b) common solvents (e.g., toluene, ethylbenze); and (c) the primary fuel components of natural gas, particularly methane. Common solvents and primary gas components, although generally of lower solubility in water, represent a toxic contribution that can be a serious risk, if they are released either into surface water or as a vapor that may subject persons living in the area to exposure.

4. ***Hydraulic fracturing additives:*** The range of hydraulic additives is very large, and difficult to assess from a risk perspective since the list is almost certainly incomplete, specific information on the chemicals is lacking, and the specific rate of usage is not offered. Thus, not knowing the composition of the specific additives and the amounts provides effectively no basis for estimating the risk of these components of the flowback or produced water, and the RDSGEIS falls seriously short in this regard. A mere laundry list of these components does not meet requirements for analysis of their potential impacts. The list is so long, and the data on each component so incomplete, that it falls far short of the data that would normally be contained in a professional scientific risk analysis. Additionally, Tables 5.4 and 5.5 use trade names, and while the New York regulators may have information on the constituents in those products, that information was not available for this review. Additionally, the public does not have access to this information, and thus the public cannot legitimately understand or evaluate the risk of these products to their health or the environment that they live in.

   Table 6.1 reports the constituents found in flowback, and effectively none of the additive compounds used in fracturing were reported in the flowback, except for the hydrocarbons that occur naturally in the hydrocarbon formations (benzene, toluene, xylene, naphthalene, etc.). In fact, the only non-fuel compound found in flowback that is also mentioned as a hydraulic fracturing additive is propylene glycol. This analysis demonstrates a significant problem in examining flowback chemical composition. Either NYSDEC is concluding that chemicals injected into the formation do not return in the flowback (improbable), or NYSDEC has not employed the correct analytical methods to evaluate flowback waste constituents.

It is not clear from the RDSGEIS how many of the additives were actually subjected to analysis in the flowback samples. Most of the chemicals listed in Table 6.1 that are used as additives will not be detected/measured by the standard methods used to determine hydrocarbons and metals. Therefore, the absence chemical additives in the flowback samples shown in the RDSGEIS is likely a function of incomplete laboratory analysis. For example, it is not clear that any attempt was made to actually measure the following three compounds in the flowback water: (1) 1-propanesulfonic acid; (2) 2-propenoic acid, homopolymer, ammonium salt; (3) acetic acid, hydroxyl-, reaction products with triethanolamine. None of the methods used by the Marcellus Shale Coalition (see Chapter 5-109) would, in this reviewer's estimation, be suitable for measuring these compounds. In fact, many, if not most of the additives, require very specialized methods for analysis; some are multiple chemicals (e.g., polymers), and some are relatively unstable (e.g., acrylamide).

There is, however, an implication that since the compounds were not subject to analysis, and thus not observed in the flowback water, they do not exist in the flowback water, which is a scientifically unjustified conclusion and almost certainly not the case.

Table 6.1 should be re-created with an additional column that indicates whether the compounds would have been measured with the analytical scheme utilized (e.g., gc-ms, icp-ms, ion chromatography for anions, etc.). Additionally, the RDSGEIS should list the analytical method required to detect each compound in the flowback. The detection limit for each method should be specified.

A full analysis for all of the additives utilized in hydraulic fracturing is indeed a challenge, but the SGEIS should clearly indicate which compounds could be measured by the protocol utilized, which could not, and what method would be required. It is likely that most if not all of the additives used that are not found in the formation water were not actually measured/determined. Thus, Table 6.1 has very limited value, and provides a distorted view of what is actually being measured.

Recommendation 7. The analytical tables for hydraulic fracturing additives should be revised to clearly show the analytical methods utilized and whether the analytical methods used, and detection limits provided by those methods, are sufficient to protect human health and the environment. The tables should verify if the additives were actually measured in the flowback water.

Recommendation 8. The RDSGEIS should include as a mitigation measure a list of analytically testing methods required to test flowback prior to disposal; these testing requirements should also be codified in the NYCRR.

A detailed risk assessment of each of the potentially toxic additives is a reasonable request. Leakage of flowback water to domestic water has been demonstrated recently in Wyoming by the U.S. EPA (2011) and represents a potential threat to ground water in New York. It is not sufficient to simply argue that gas wells will not leak, since leaks are now apparent in certain well fields (e.g., most recently in Wyoming (US EPA, 2011a)), as well as in Pennsylvania (Pennsylvania DEC, 2011). When leaks occur, it is probable that the greatest risk will be from the naturally occurring substances, but the additives also pose a non-trivial risk.

Practically speaking, it is more efficient and cost-effective to limit the additives used, rather than test for every possible additive in the flowback. Other governments and agencies have developed simplified methods and lists for prohibiting toxic additives, and assessing their risk (e.g., OSPAR PLONOR, C-NLOPB Guidelines, The Norwegian Pollution Control Authority; see accompanying report of Susan Harvey regarding additives). NYS could develop a similar list of prohibited additives, and a process for approving additives for use that will offer a method for reducing risks to both the public and workers.

Some of the additives being used are serious carcinogens, and may be difficult to measure. Two examples of these are acrylamide and acrylonitrile. Both are carcinogenic and, while not long lived in the environment, can create serious exposure concerns to workers and the public.

Acrylonitrile has been found in Pennsylvania and/or West Virginia in water samples taken near hydraulic fracturing operations (data received from individuals who had samples analyzed). It was also observed in flowback water from the Marcellus Shale Coalition (page 5-115 of the RDSGEIS). Acrylonitrile is a carcinogenic (US EPA, 2011b) and exclusively anthropogenic compound. It can be measured in a standard purge and trap gc-ms method, and has been used in Pennsylvania, and is indicated in a patent issued to Halliburton (Halliburton Energy Services, U.S. Patent 7799744). This compound is one of the more toxic compounds used as additives, yet is not even mentioned in the RDSGEIS (Table 5.9). Failure to include a chemical additive that is commonly used and known to be carcinogenic and toxic to humans is a serious deficiency in the RDSGEIS.

Failure to include Acrylonitrile in Table 5.9 raises uncertainty in what other harmful chemical were not listed or examined in the RDSGEIS. Additionally, the RDGSEIS lacks of information on additives use rates. Therefore, the RDSGEIS analysis of the potential significant adverse impact of additive use is, at the least, incomplete.

Acrylonitrile, butadiene and styrene (ABS polymer) are mixed "on the fly" with the uncoated propping agent to create a polymer covering on the propping agent. From the Halliburton patent:

> Some suitable polymers include, but are not limited to, acrylic polymers such as acrylonitrile polymers, acrylonitrile copolymers, and mixtures thereof. Some preferred polymers include homopolymers and copolymers of polyacrylonitrile (including copolymers of acrylonitrile and methyl acrylate, methyl methacrylate, vinyl chloride, styrene and butadiene), polyacylates, polymethacrylates, poly(vinyl alcohol) and its derivatives, and mixtures thereof. As used herein the term "acrylic" polymers refers to any synthetic polymer composed of at least 85% by weight of acrylonitrile units (the Federal Trade Commission definition). Thus, the definition of the term may include homopolymers of polyacrylonitrile and copolymers containing polyacrylonitrile. Usually they are copolymers of acrylonitrile and one or more of the following: methyl acrylate, methyl methacrylate, vinyl chloride, styrene, butadiene. However, polymers that do not meet the definition of an acrylic polymer (such as those having less than 85% acrylonitrile) may also be suitable. For instance, Example 3 uses poly(acrylonitrile-co-butadiene-co-styrene) that contains approximately 25 wt % acrylonitrile.

Further down the patent, the "on-the-fly" process is described.

> In particular embodiments of the present invention, the particulates may be coated with the polymer solution and introduced into the treatment fluid, which acts as the aqueous medium, directly prior to being introduced into a subterranean formation in an on-the-fly treatment.

This process is likely to be inefficient and likely to release substantial amounts of acrylonitrile and styrene into the water used in the fracturing process. Acrylonitrile has been found in flowback water (page 5-115 of the RDSGEIS), and reports are available that show that it has been detected in surface and ground water in Pennsylvania, and is perhaps one of the most unambiguous anthropogenic indicators that off-site contaminated water has been in communication with the water used in the fracturing process. NYSDEC should determine if this polymer and application method is appropriate for use in New York, and require acrylonitrile and styrene as two of the suite of compounds to be analyzed in flowback before it leaves the wellsite.

Recommendation 8. The NYSDEC should re-examine the additives used in hydraulic fracturing and conduct a much more detailed analysis of the risk of these compounds. Specifically , acrylamide and acrylonitrile, a carcinogenic and exclusively anthropogenic compound used in hydraulic fracturing, should be measured in flowback water, and an assessment made as to whether and/or how use of this compound should be permitted. The conclusions of such analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

B. The analytical data presented in Tables 5.10, 5.23, 5.24 and 6.1 all indicate a lack of detailed understanding of the quality of the flowback, and indicate

an inadequate understanding of the methods necessary to fully characterize the wastewater.

The errors in Tables 5.10, 5.23, 5.24 and 6.1 are sufficiently glaring that they need a much more detailed review. For example, in Table 5.10, the dissolved metal concentrations in some cases are higher than total metals. Iron, for example, has a median concentration 29.2 mg/L, but the dissolved median concentration is 63.25 mg/L. Similarly, the mean manganese concentration is 1.89 mg/L, while the dissolved manganese concentration is 2.975 mg/L. There cannot be higher amounts of dissolved iron and manganese than total iron and manganese.

The data from the Marcellus Shale Coalition was not displayed, other than as a table of compound detections. These samples were collected from 19 gas well sites in Pennsylvania and West Virginia. All samples were collected by a single contractor and the analyses performed by a single laboratory, which should reduce the variability. This would appear to be a very valuable data set, but surprisingly, no data were presented regarding concentrations of the analytes. Some comments were provided on the types of compounds detected, although it was not clear which types of water contained these constituents. Additionally, chlorinated hydrocarbon insecticides were detected, which is very surprising, since these compounds could not have been found in the formation water, and have not been used in the U.S. since the 1970's. They are likely false positives, although it is not possible to make that determination, based on the discussion in the RDSGEIS. Data obtained from the Marcellus Shale Coalition should be presented, which compares, for example, flowback water from different wells under similar conditions (e.g., immediate flowback versus flowback in subsequent days).

Finally, the data in Table 6.1, which focuses on the additives used in hydraulic fracturing, is problematic. As discussed above, it is highly unlikely that attempts to determine the concentrations of the fracturing additives were actually conducted, since many of these compounds are difficult to determine. The implication remains, however from Table 6.1, that these compounds were actually considered in some appropriate analytical scheme. This is almost certainly not the case, and Table 6.1 should be clarified.

Recommendation 9. Each of the SGEIS tables of analytical data should be reviewed by an analytical chemist, and the data be presented in a scientifically accurate and quality controlled manner. The data in Table 6.1 should be clarified and the compounds which were not subjected to specific analyses should be identified.

C. Permissible treatment of the flowback and the produced water is not well defined. It is unclear how the post-treatment residual salts and radioactivity will be managed. There does not appear to be any complete treatment of these waters that will be permitted in New York.

There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, (3) treatment in municipal facilities, or (4) treatment in privately owned facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified.

"Treatment" of flowback for *reuse* is discussed in Section 5.12. Reuse of the flowback conserves fresh water and allows contaminated water to be used instead during fracturing. However, the RDSGEIS only considered treatments for removal of salts that would allow for reuse in other hydraulic fracturing operations, and evaluated how specific requirements for reuse could be met by various treatment processes (e.g., membrane, ion exchange or evaporative processes). It did not analyze the residual contaminants removed by evaporative or membrane processes and thus concentrated, or how those contaminants would be managed, other than to indicate that the residual salts, or concentrated brine will require "further treatment or disposal." The SGEIS must address how this highly concentrated and toxic residue will be regulated and managed.

Three hundred tons of salt will exist in one million gallons of flowback or produced water brine, if you assume a 7% (70,000 mg/L) salt solution. The source of the alpha emitters also must be identified, as is discussed above. If, as is suspected, polonium is present in the flowback water, it represents an additional management burden of the flowback and produced water that must be evaluated.

Beyond reuse, the disposal options considered in the RDSGEIS only included injection wells (although there are currently no industrial waste injection wells capable of handling this wastewater in NYS), municipal sewage treatment facilities (of which there are currently none that are permitted to accept flowback and produced water), and private treatment plants (of which none currently exist in New York). Therefore the RDSGEIS examines options that do not exist, and does an incomplete job of that examination.

The RDSGEIS did not consider whether there are other, less environmentally harmful, options that exist for treatment and disposal of flowback and produced water. More importantly, the RDSGEIS fails to evaluate the potentially significant adverse environmental impacts and human health risks associated with each treatment and disposal option.

Section 6.1.8.1 indicates that "[f]lowback water may be sent to POTW's", but then describes the limitations that may preclude disposal of these waters in POTWs. The RDSGEIS requires that a "facility must first evaluate the pollutants present in that source of wastewater against an analysis of the capabilities of the individual treatment units and the treatment system as a whole to treat these

pollutants" (page 6-57); however, before such an evaluation can be conducted, the well operator must obtain a complete analysis of the flowback water (which as explained above, has not been done).

Additionally, the diversity of the flowback water quality is such that a POTW would need to conduct an extensive and expensive analysis of each water type that was delivered to the POTW under those guidelines. Since most of the additives are clearly not subject to routine analyses, it appears doubtful that a POTW could ever accept this type of waste. Also, if the limitation of 15 pCi/L of radium in the influent is enforced, a large portion (as yet not determined) of the flowback water could not even be accepted. Finally, the requirement of a complete description of the contaminants in the water is likely to add an additional burden to using POTW's for disposal, that this option may be precluded for most of the flowback water. Therefore, the proposal to use POTWs as a potential treatment and disposal method is scientifically and technically unsupported.

One serious problem with the proposed discharge (dilution) of fracture treatment wastewater via a municipal or privately owned treatment plant is the observed increases in trihalomethane (THM) concentrations in drinking water reported in the public media (Frazier and Murray, 2011), due to the presence of increased bromide concentrations. Bromide is more reactive than chloride in formation of trihalomethanes, and even though bromide concentrations are generally lower than chloride concentrations, the increased reactivity of bromide generates increased amounts of bromodichloromethane and dibromochloromethane (Chowdhury, et al., 2010). Continued violations of an 80microgram/L THM standard may ultimately require a drinking water treatment plant to convert from a standard and cost effective chlorination disinfection treatment to a more expensive chloramines process for water treatment. Although there are many factors affecting THM production in aspecific water, simple (and cheap) dilution of fracture treatment water in a stream can result in a more expensive treatment for disinfection of drinking water. This transfer of costs to the public should not be permitted.

NORM, the inorganic substances, and the organic compounds from the formation also represent serious contamination potential and require an appropriate level of treatment. The exact method of treatment that NYSDEC expects to require for any municipal or private treatment facilities that may be permitted is unclear. The RDSGEIS suggests that there will be some level of wastewater dilution through discharge into a receiving stream, at least in some cases. The analysis should be much more explicit about how wastewaters will be treated, both in-state and out-of-state. New drilling operations should not be permitted until adequate management/disposal of these waters is evaluated, with public comment required on the proposed methods, an analysis of the impacts associated with each, as well as mitigation measures as required by SEQRA.

Injection of the waste fluids into fully permitted underground injection control (UIC) wells is an option also, although this method is problematic due to the lack of permitted wells in New York, and the distance the contaminated water would need to be trucked in order to dispose of it in other states where permitted wells exist (e.g., Ohio). The recent seismic activity in Ohio from disposal of fracturing fluids also raises serious concerns whether this option is safe. Given the difficulties of wastewater treatment, UIC is likely the popular choice for wastewater disposal from the Marcellus region. However, NYS' increase wastewater load, along with increased wastewater generated from the increased drilling in Ohio and surrounding states, will likely pose an injection capacity problem for Ohio UIC wells. The RDSGEIS has not examined whether it is possible, or safe to install disposal wells in NYS' or whether a nearby state has sufficient capacity to inject NYS' incremental waste load, or whether this is the best technical solution. These are all potential significant adverse impacts that should be, but are not, addressed in the RDSGEIS.

Out-of-state management of waste is contemplated in Section 5.13.3.3., but is identified as not being within the regulatory purview of New York. However, simply stating that wastewater will likely be managed "out-of-state" is insufficient. Wastewater handling is an unmitigated significant impact in the RDSGEIS as currently proposed. The proposal to export NYS' wastewater and not examine this significant impact is not justified.

NYSDEC should instead evaluate the impacts of, clear cradle-to-grave oversight and management, identify the best solutions for waste handling, and include those requirements as mitigation measures in the RDSGEIS.

Furthermore, even if some export of wastewater is permitted, SEQRA requires analysis of the impacts of any potential waste management options, even if they are to occur outside of New York.

Finally, road spreading for dust control and de-icing would apparently (and appropriately) not be allowed for flowback water, but could be used under certain conditions for the produced brines. A rationale for this distinction is not provided, and permitting road spreading of produced water is not recommended, since the brines will have higher concentrations of NORM than the flowback water, and may include polonium. Some rationale should be provided for this distinction, particularly since it is apparently unknown if any of the hydraulic fracturing additives are even detected in the flowback water (see Table 6.1). It is clear, however, that the NYSDEC is concerned about using the brines for roads and will require a specific permit for this application. Whether a permit will be granted presumably will depend on the amount of radioactivity present in the water. Under no circumstances should brine solution that has a gross alpha concentration of greater than 15 pCi/L be applied to roads. Ultimately, this practice should not be allowed – there are simply too many questions about the identity and amount of contaminants in these fluids.

Recommendation 10: The RDSGEIS should identify and evaluate the impacts of the various options that are proposed to be permitted for management of wastewater, and identify any proposed mitigation for identified significant adverse impacts, which should be set forth in the proposed regulations.

Recommendation 11. Specific influent contaminant load restrictions need to be explicitly identified including those for: fracking additives, NORM (including gross alpha), TDS and other relevant contaminants in this management description.

D. **Cuttings disposal:** Disposal of cuttings is considered in the RDSGEIS, although the treatment is incomplete. Cuttings from the shales of marine origin such as the Marcellus Shale (particularly the horizontal cuttings) will require further examination to determine if they contain large amounts of salts, similar to the produced brines, or if they contain excessive alpha emitters. While the measurements of radioactivity, based on a gamma detector, do not indicate high levels of radioactivity, further analysis is required to determine the leachability of these cuttings. Polonium is only a very weak gamma emitter, and thus it would not be observed by simple gamma counting. The organic (reducing) components of the shales chemically trap uranium and potentially other radionuclides, and when they are subject to oxidizing conditions, increases in the solubility/mobility of some of the radionuclides (particularly uranium) is likely. The leachability of these cuttings under oxidizing conditions thus requires further analysis, as discussed at the bottom of page 6-65. However, these determinations need to be made, and the risks and potential mitigation identified, *prior* to permitting the wells.

Recommendation 12. The RDSGEIS must fully evaluate the potential significant adverse impacts of cuttings disposal and identify any necessary mitigation to address such impacts, which should be set forth in the proposed regulations.

E. **Odors are a continuing concern from gas wells:** A variety of chemicals are present in hydrocarbon formations that can present a serious odor problem, which can be both a serious human health problem and affect the quality of life of persons living near these sites. A very common, but toxic, constituent is hydrogen sulfide, characterized by a rotten egg smell. Other organic sulfides can also be present, including a variety of alkyl sulfides. Odors are very difficult to regulate, due to the vagaries associated with odor detection, acclimation, and differential effects on different persons. The severity of an odor is in the nose of the beholder. Thus, each well should be assessed to determine the potential of migration of volatile substances from the well operation to surrounding residents. Odor complaints should be taken seriously, and the presumption should be that an odor complaint is valid, and an investigation of the source required.

Hydrogen sulfide is, however, probably the most acutely toxic component present in a potential natural gas leak, and it can pose a serious health risk to surrounding residents, in addition to causing odor complaints. Sulfide monitors should be required at least two points, corresponding to most probable downwind locations at the fenceline. When hydrogen sulfide is detected above the odor thresholds, the source of the odor should be identified and eliminated.

Setbacks from an operating well will help to minimize the impact of odors on the surrounding residents. (Setbacks are discussed in further detail in the accompanying reports being submitted under cover of the Louis Berger Group.)

Recommendation 13. The RDSGEIS must fully evaluate the potential significant adverse impacts associated with odors and hydrogen sulfide emissions, and identify any necessary mitigation to address such impacts, which should be set forth in the proposed regulations.

F. **Monitoring of nearby domestic wells for contamination from gas drilling operations should be conducted at regular intervals during and following hydraulic fracturing.** While the drilling company would be required to test domestic wells for contamination prior to gas development operations, these same wells should be tested during production, and subsequent to discontinuing production to determine if hydraulic fracturing has resulted in contamination (See the accompanying report of Dr. Tom Myers). At present, the documents are silent on this requirement and effectively transfer this responsibility to the well owner. The analytes that should be determined should include, at a minimum, the components of natural gas (methane, ethane, etc.) and also toxic volatiles from the formation water (benzene, toluene, xylenes), salts and relevant inorganic contaminants, and the additives used during the hydraulic fracturing. This list should be developed based on those specific additives used.

Recommendation 14. The RDSGEIS and proposed regulations should require that monitoring of domestic wells situated in close proximity to gas drilling operations to be required at regular intervals during and following hydraulic fracturing. Because of the slow movement of groundwater, routine analysis of those domestic wells should be continued at least 20 years.

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Attachment 4

Ralph Seiler, Ph.D.

Review of the

Revised Draft
Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

Prepared for:
Natural Resources Defense Council
New York, New York

Prepared by
Ralph Seiler, PhD
(rlseiler@juno.com)
Carson City, NV

1/11/12

This document represents a review of the Revised Draft Supplementary Generic Environmental Impact Statement (RDSGEIS) regarding the hydraulic fracturing proposals to develop natural gas wells in New York. I have specifically examined issues related to NORM in the flowback/produced brine, as well as of radon in the gas itself. My comments supplement those of Glenn C. Miller, Ph.D.

Issue 1.

<u>Unidentified sources of gross alpha and beta radioactivity in flowback water and production brine.</u>

Gross alpha radioactivity in the brines (Appendix 13) and flowback water (Table 5-24) can be very high. In the brines, gross alpha is usually from 8,000 to 20,000 pCi/L, with a maximum of 120,000 pCi/L (Well Webster T1). In the brine samples with high gross alpha, the sum of uranium (U) , thorium (Th) , radium-226 (^{226}Ra) and radium-228 (^{228}Ra activities is much less than the measured gross alpha. Individual analyses of flowback water are not given, but the aggregated data similarly suggest that the sum of U, Th, and ^{226}Ra and ^{228}Ra activities is also much less than the measured gross alpha. These results indicate one of two things:

1. There are analytical problems with the gross alpha measurements, probably caused by the high salinity of the water.
2. There is an unidentified alpha emitter present in the water.

High salinity can cause the measured gross alpha to significantly overestimate the actual alpha activity of a sample (Arndt and West, 2007). The recommended mass placed on a planchet for gross alpha is only100 mg, so given a brine Total Dissolved Solids (TDS) of 350,000 mg/L (p. 6-61), only ~0.4 ml of sample should be placed on a planchet. The high TDS means it is easy for too much mass to be placed on the planchet, or the small volume means the mass may be unevenly distributed. Both of these factors can contribute to reduced precision and accuracy in the gross alpha analysis.

Appendix 13 indicates all of the relatively long-lived, naturally occurring alpha emitters in the brines were measured except polonium-210 (^{210}Po). Radon itself would not contribute at all to the measured gross alpha because it is a gas. In the gross alpha measurement, an aliquot of sample water is placed in a planchet and evaporated to dryness. After drying, the planchet is commonly flamed until it glows red to drive off hygroscopic water from the salts. Because of this, alpha radioactivity from radon does not contribute to gross alpha radioactivity.

^{210}Po normally binds strongly to sediment particles and concentrations in fresh groundwater are typically <1 pCi/L. In some geochemical settings ^{210}Po activities have exceeded 500 pCi/L in drinking-water wells in the US (Seiler et al., 2011), however this is extremely rare and fewer than 100 US wells have been reported with >15 pCi/L. ^{210}Po is known to be present in oil-field brines (Parfenov, 1974), however, the reported ^{210}Po activities in the brines were relatively low, about 100 pCi/L.

On p. 6-205 the RDSGEIS states radium is the primary radionuclide of concern, but this may not be the case if the excess alpha radioactivity is caused by the presence of ^{210}Po. If ^{210}Po is present in high levels, it may be much harder and more expensive to treat the contaminated water and manage the waste. Ra can be removed from water with relatively simple technology such as water softeners. On the other hand, Charles County in Maryland found the best way to remove Po from a contaminated public-supply well was with reverse osmosis. Treating millions of gallons of brine with reverse osmosis would be expensive and difficult, and could increase the cost to the public if treated at a public treatment facility. It could cause the gas to be more expensive to the consumer if the operator is made to bear the cost of treatment at an on-site or privately-owned treatment facility.

Gross beta radioactivity in many of the wells in some of the wells is several thousand pCi/L. To evaluate the significance of this, you need to know the potassium concentrations because ^{40}K is the source of almost all natural beta. If gross beta minus a correction factor for K were to exceed 50 pCi/L in a municipal well, the operator would have to identify the major contributors to gross beta. One

potential contributor to gross beta is lead-210 (^{210}Pb), which was not measured. This is potentially important because ^{210}Pb decays to ^{210}Po and could support it in the water.

Issue 1 Recommendations

The cause of the excess alpha radioactivity in the brine and flowback samples needs to be determined. ^{210}Po may be present at high concentrations and could pose a significant risk to health and the environment if oil-field brines are inadequately disposed of because it bioaccumulates. Samples from some of the more contaminated wells should be reanalyzed for the same suite of analytes as before, except this time include ^{210}Po. Redoing the complete suite will provide an idea on how adequately the less expensive gross alpha analysis identifies the presence of ^{210}Po. All samples analyzed for NORM (e.g. p. 6-61) as part of the regulatory process should include ^{210}Po, at least until it has been demonstrated that ^{210}Po is not an important source of alpha radioactivity.

NYSDEC should identify what the important contributors to gross alpha are (probably radium and ^{210}Po) and identify how, if at all, the brine and flowback water will be treated, taking economic considerations into account. Failure to do so constitutes a potentially significant adverse impact that would not have been disclosed or mitigated.

The principal contributer to the gross beta radioactivity is probably potassium-40 (^{40}K), but this should be confirmed because ^{210}Pb can also contribute to gross beta, and if present ^{210}Pb can support aqueous ^{210}Po. An estimated ^{40}K activity, based on the potassium (K) concentrations for the brines, should be added to Appendix 13 so the gross beta measurements can be evaluated. It is presumed that K was measured, even though no major ion analyses for the brines were found in the RDSGEIS. A theoretical activity ratio of 0.818 pCi/mg was reported by Friedlander et al. (1981) and can be used to convert concentrations to activities.

Issue 2.

Documentation of analytical methods

It is important that all analytical methods that will be used to analyze pollutant levels are well documented, but the RDSGEIS does not indicate what they would be.

Issue 2 Recommendations

It is presumed the alpha emitters were analyzed by alpha spectrometry, but the RDSGEIS should confirm this. The RDSGEIS also needs to provide reporting limits for the other analytes, not just provide a list of the analytes to be measured. An analysis for arsenic is useless if the reporting limit is 50 ppb when the drinking water standard is 10 ppb.

Documentation of the method is particularly important for the gross alpha analysis. EPA Method 900.0 for gross alpha allows samples to be composited quarterly and allowed to sit for up to a year before analysis. Unfortunately, the EPA approved analytical method can allow more than 60% of the ^{210}Po in a sample to be lost due to decay during that year (Seiler et al., 2011). A simple statement that Method 900.0 will be followed is inadequate. The RDSGEIS should explicitly state that samples for gross alpha will not be composited and must be analyzed within 3 days of sample collection. Analysis within 3 days is SOP for many agencies and finding labs that can meet that requirement should not be a problem.

Issue 3.

Radon in Natural Gas

Radon is known to be present in natural gas and will be delivered with the natural gas to consumers. Burning of natural gas in stoves, water heaters, and furnaces does not affect the radioactivity of radon and consumers will be potentially exposed to increased levels of atmospheric radon.

The RDSGEIS does not include measurements of radon concentrations in the natural gas, nor does it indicate plans to monitor it. Radon concentrations in natural gas are extremely variable and can be very high. Natural gas from Texas and Kansas had radon concentrations ranging between about 5 and 1500 pCi/L (Dixon 2001,

Table 2). This raises the possibility that radon concentrations in gas from the Marcellus Shale could be much higher values than are in the gas currently being used. In addition, the hydraulic fracturing process would be designed to maximize extraction of natural gas from the formation, and as a consequence may also maximize extraction of radon from the formation.

The pipeline from well heads tapping the Marcellus Shale will be much shorter than the existing 1500 mile pipeline delivering gas from Texas/Louisiana. Assuming the gas moves through the pipeline at 10 mph, it would take 6.25 days for gas from the wellhead to the consumer, and during this time ~68 percent of the radon will decay. If wellheads in the Marcellus Shale are only 100 miles from the consumer then only 7 percent of the radon would have decayed. Because of this, even if the wellhead radon concentrations in gas from the Marcellus Shale were identical to those of the currently used natural gas, consumers would be exposed to greater radon concentrations because the wellheads are closer.

Dixon (2001) provided a risk assessment for the radon in natural gas in the UK. The average radon in natural gas from the UK wells was 5.4 pCi/L, and, as a worst-case scenario, Dixon (2001) assumed that there was instantaneous delivery of the gas so that no radon decay occurred between the wellhead and the consumer. Dixon (2001) concluded there was negligible risk to the public from release of radon in combustion gasses, and that the average dose to the public using 100 cubic meters of gas would be only 4 microSieverts per year (μSv/yr). The greatest risk was to workers in large commercial kitchens who would receive a dose of 19 μSv/yr.

Issue 3 Recommendations

The risk to the public from radon in the natural gas probably is small. Measurements of radon in the gas are needed, however, to confirm that radon levels in the gas are within the expected range. A new risk assessment should be made using actual measurements of radon in gas from the Marcellus Shale and other factors specific to New York, such as the background radon concentration for the area. For

a worst-case scenario the assumption should be made that there is instantaneous delivery of gas from the wellhead to the consumer.

Issue 4.

<u>^{210}Po Buildup in Delivery Pipes</u>

On page 6-205 of the RDSGEIS there is a discussion of scale buildup in pipes and equipment, but the discussion seems to indicate Ra is the principle radionuclide of concern. If radon, ^{210}Pb or ^{210}Po are present at high concentrations in the water or gas, a more significant health risk for workers could be ^{210}Po in the scale. Summerlin and Prichard (1985) evaluated this and concluded that workers cleaning impellers could be exposed to high levels of atmospheric ^{210}Po.

Consumers and State and Local workers may also be exposed to ^{210}Po, which will form in scale on all pipes carrying natural gas with radon in it. The amount of ^{210}Po buildup will depend on the amount of radon in the gas. Plumbers and City/State employees working on the pipes may not know what precautions need to be taken, and thus could be exposed to ^{210}Po in the scale.

Another issue is the volatility of ^{210}Po, which is completely volatile at temperatures above 500°C (Radford and Hunt, 1964). Because of this, ^{210}Po that accumulates near burners that have been turned off may be vaporized when burners are turned on. This could potentially expose consumers to health risks from inhaling ^{210}Po. In cases of accidents or fires involving gas lines, first responders and the public near the incident could also be exposed to ^{210}Po through inhalation. This risk is not specific to gas from the Marcellus Shale. The health risks, however, would be related to the amount of radon in the gas and thus the amount of ^{210}Po that would build up, and this is not known for gas from the Marcellus Shale.

<u>Issue 4 Recommendations</u>

Measurements of radon in natural gas from the Marcellus Shale need to be made. A risk assessment should be made for inhalation of ^{210}Po resulting from scale buildup in delivery pipes.

Issue 5.

<u>^{210}Po drinking-water standards</u>

Table 2-3 presents drinking water standards for radionuclides. The US does not have a standard specifically for ^{210}Po largely because ^{210}Po is extraordinarily rare in drinking water. The US standard for ^{210}Po is exceeded if the gross alpha minus the U activity exceeds 15 pCi/L. Canada and the European Union have set drinking-water standards specific for ^{210}Po at 5.4 and 2.7 pCi/L, respectively (Health Canada, 2007; Commission of the European Communities, 2001). The regulatory use of the gross alpha standard assumes it will adequately identify samples with ^{210}Po levels that exceed health safety standards. For several reasons related to Po chemistry and the gross alpha analytical method, this may not be the case (e.g. Seiler, 2011).

<u>Item 5 Recommendations</u>

For any analysis where there may be actual human exposure, the RSDGEIS should analyze ^{210}Po analyses using alpha spectrometry rather than using gross-alpha analyses as an inexpensive but inadequate surrogate.

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Attachment 5

Susan Christopherson, Ph.D.

Memorandum

To: Kate Sinding, Natural Resources Defense Council

From: Susan Christopherson, Ph.D.

Date: January 11, 2012

This memorandum comments on issues in the sections of the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) and accompanying documents that address the social and economic impacts of natural gas development using high volume hydraulic fracturing (HVHF) proposed for New York, and evaluates the sufficiency of the impact analysis presented and the mitigation measures identified. HVHF describes a stage in the gas extraction process whereby large amounts of water, toxic chemicals, and sand are injected at high pressure to create fissures in low-permeability formations and thereby allow the release of gas. The process is capital intensive, and throughout its duration, poses significant environmental risks. The New York State Department of Environmental Conservation (NYSDEC or the Department) is charged with identifying and evaluating the impacts of gas development using HVHF, including both the benefits and the costs that will be borne by the communities and counties where drilling will occur.

In preparing these comments, the key documents reviewed include:

- The 2009 scope of work for the SGEIS.
- Comments prepared by AKRF and other technical experts on the 2009 draft SGEIS.
- A report prepared by Sammons, Dutton and Blankenship (2010) in response to comments on the 2009 draft SGEIS analysis of socio-economic impacts.
- The RDSGEIS released in September 2011 and particularly sections addressing socioeconomic and community impacts (6.8 and 6.12) and mitigation (7.0).
- The Economic Assessment Report (EAR) prepared by Environment and Ecology LLC to accompany the RDSGEIS.

These comments also draw on my own research on input/output models and community impacts and on research that has been conducted on the social and economic impacts of natural gas drilling in shale gas plays across the United States. Other documents cited in these comments are included in the reference list.

Although NYSDEC has included more information on the social and economic impacts of gas development using HVHF in the RDSGEIS than it did in the 2009 draft, the RDSGEIS still does not effectively assess those impacts or provide appropriate mitigation strategies. These comments identify areas of social and economic impact that require additional or revised research or analysis in the SGEIS. Overall, the discussion of social and economic impacts in the RDSGEIS is poorly organized. Social and economic topics are discussed in several sections of the RDSGEIS and statements are made in some sections that are contradicted by evidence in others. The differences between the social and economic impacts of vertical and horizontal drilling are not addressed in a systematic way. Critical assumptions underlying the socioeconomic

impact analysis were accepted from industry sources (the Independent Oil and Gas Association of New York or IOGA NY) without independent verification.

Substantive concerns include the following:

1. The assessment of economic benefits (jobs and taxes) relies on questionable assumptions about the amount of gas extractable in the New York portion of the Marcellus Shale. The range of estimates for extractable gas appears to be skewed to the high end, leading to an overestimation of economic benefits.

2. The model used to assess social and economic impacts presents natural gas development as a gradual, predictable process beginning with a "ramp-up" period and then proceeding through a regular pattern of well development over time. Experience from shale plays in the Western United States demonstrates that volatility and unpredictability are intrinsic to natural gas extraction, as operating companies assess their commercial options from one shale play to another or within one shale play and allocate rigs to respond to those options. The model used in the RDSGEIS is misleading, giving the impression that communities in the drilling regions will experience economic disruption only once, during a ramp-up phase, rather than periodically, as operating companies repeatedly enter and leave the region. The problems with the model are then compounded, as projected impacts on population, jobs, and housing are predicated on one-time ramp-up and adjustment phases rather than on a process in which rigs may move in, move out, and move in again, in an unpredictable sequence. Because many of the negative social and economic impacts of HVHF gas extraction (such as housing shortages followed by excess supply) are a consequence of unpredictable development, the model used in the RDSGEIS cannot appropriately assess those impacts. The limitations of the model should have been explained with reference to the literature that describes the irregular, unpredictable course of natural gas development, including rig movement among shale plays and the frequency of re-fracturing wells.

3. The RDSGEIS does not assess public costs associated with natural gas development. A fiscal impact analysis of the base costs to the state and localities that will occur with any amount of HVHF gas development is required along with an estimate of how costs will increase and accumulate as development expands. Although some of the potential community character and economic costs associated with the projected drilling scenarios are mentioned in the RDSGEIS, there is no attempt to quantify those costs to the state or localities either as part of the modeling process or separately.

4. The long-term economic consequences of HVHF gas development for the regions where production occurs are not addressed despite a widely recognized literature indicating that such regions have poor economic outcomes when resource extraction ends.

5. Mitigation of enumerated negative social and economic impacts of HVHF gas development is presumed to occur by means of phased development and regulation of the industry, but no evidence or information is provided to indicate whether, and if so how, that would occur. For example, NYSDEC proposes to ask operators to identify inconsistencies with local zoning and other comprehensive land use planning, but there is no explanation of how the inconsistencies will be addressed in the permitting process or regulatory system. All mechanisms that will be relied on to address adverse social

and economic impacts need to be defined and incorporated into enforceable mitigation measures.

Part I of these comments focuses on the socioeconomic impact analysis in section 6.8 of the RDSGEIS. Section 6.8 adopts the assumptions utilized in the EAR and summarizes its more detailed description of anticipated impacts from HVHF gas development. Part I.A pays particular attention to the model employed in the EAR and its assumptions about how the exploratory, drilling, production, and resource depletion phases of development will occur. These assumptions do not adequately consider the uncertainties and risks associated with HVHF gas development. Part I.B comments on particular issues and areas of impact addressed in the RDSGEIS. Part II discusses issues pertaining to the distribution of economic benefits that are raised by the EAR but not addressed in the RDSGEIS. Part III comments on the mitigation proposed for potentially significant social and economic impacts.

I. NYSDEC's Socioeconomic Impact Analysis

A. The Unpredictability of Natural Gas Production and How It Is Treated in the RDSGEIS

The EAR's projections concerning population, jobs, housing, and revenue are predicated on the assumption of a regular, predictable roll-out of the exploratory, drilling, and production phases of the natural gas development process, rather than the irregular pattern typically associated with such development.

Natural gas drilling is a speculative venture and the amount of commercially extractable gas from any particular well is uncertain. Because of the speculative nature of the industry, there are significant economic risks associated with natural gas production. These risks are magnified by the costs involved in natural gas development, which uses capital-intensive technologies such as those engaged in hydraulic fracturing.

The industry is organized in such a way that these risks can be lessened. For example, a limited number of rigs is available nationally, and they are deployed among and within natural gas plays based on calculations of well productivity and commercial return. The drilling labor force is not fixed to a place, but moves with the rigs based on operator company strategies. Work is carried out by contractors on a project-by-project basis to maximize flexibility and efficient deployment of the specialized skills needed.

Because of the speculative character of commercial development of natural gas plays, there are uncertainties in how any shale gas play or portion of a play will be developed. What this means in practical terms is that the regions where shale gas development occurs can experience considerable volatility in the timing of well development and in the scale of well development (in the total number of wells). This central feature of natural gas development has critical implications for the economies of natural gas development regions. As production fluctuates, regions may experience short- and medium-term volatility in population, jobs, revenues, and housing vacancies (Best, 2009; Headwaters Economics, 2011; Jacquet, 2009; Sammons, Dutton and Blankenship, 2010).

The EAR does recognize both production volatility and price volatility in the gas industry. In describing national drilling activity, the authors report: "The number of active gas

drilling rigs fluctuated substantially over the decade, with the number of rigs in the most active quarter being 2.35 times the number in the least active quarter." (EAR, 2-2). In New York, "the average wellhead price for natural gas remained at relatively low levels in the 1990s, generally increased thereafter, reaching a peak in 2008, and then fell sharply in 2009." (EAR, 3-12).

The EAR also briefly mentions the difficulties that the unpredictability and volatility of natural gas development presents for predicting social and economic impacts (e.g., EAR, 4-59, 4-111). The model used to project socioeconomic impacts ignores those issues, however, and assumes instead that the HVHF natural gas development in New York will have a different pattern than that historically associated with such development. Rather than occurring in irregularly recurring waves (or "boom-bust cycles"), development in New York is assumed to be steady and predictable.

The RDSGEIS mentions the uncertainty and variation in well productivity in sections not addressing socioeconomic impacts (RDSGEIS, 2-5, 2-62, 2-74, 4-17). However, the section of the RDSGEIS that specifically addresses socioeconomic impacts (Section 6.8) ignores the evidence of unpredictability in the pace and scale (timing and total well development) of natural gas development from New York counties with vertical well development and from other shale plays. Instead, it reports results from the model used in the EAR to project social and economic impacts from HVHF gas development that assume a regular, incremental, and predictable pattern of well development and production over a 60-year period, both on a statewide basis in three defined regions and under two development scenarios (low and average). Like the EAR, the RDSGEIS neglects the implications of variable well productivity and commercial viability -- critical considerations that will affect the pace and scale of drilling as well as its geographic distribution.

A1. Uncertainties Regarding Well Productivity

<u>The RDSGEIS and accompanying EAR do not meaningfully recognize a central category of uncertainties that will affect the pace and scale of drilling – the uncertainties surrounding well productivity.</u> Instead, NYSDEC states with respect to the low and average development scenarios analyzed:

> Both development scenarios assume a <u>consistent</u> timeline for development and production. Development is assumed to occur for a period of 30 years, starting with a 10-year ramp-up period. The number of new wells constructed each year is assumed to reach the maximum in Year 10 and to continue at this level until Year 30, when all new well construction is assumed to end.

(RDSGEIS, 6-209).

This approach is one of the major weaknesses of the RDSGEIS because the assumptions of a 30-year well production cycle and a sub-regionally consistent roll-out of wells that will move through the drilling and production phases over 60 years are not supported by evidence from other shale plays. In fact, there is sufficient evidence of precipitous declines in well productivity and the costs of HVHF gas development relative to ultimate recovery to raise questions about why the 30-year development/60-year productivity profile was adopted (Berman, 2010; Berman and Pittinger, 2011; Hughes,

2011; Urbina, 2011). In an analysis of shale gas wells across shale plays, Berman and Pittinger (2011) found thousands of wells that dropped below commercially viable production between 5 and 12 years after initial drilling. The average commercial life of these wells was 8 years. NYSDEC should not have used data provided only by IOGA to construct the roll-out model; rather, it should have obtained evidence and data from independent sources who do not stand to benefit from the projection of long-term, predictable resource development.

Another example of questionable assumptions that likely over-estimate potential gas extraction from the New York portion of the Marcellus Shale is the well productivity projections used in the EAR. These are presented in Tables 4-3, 4-4 and 4-5 of the EAR. Although ultimate recovery figures are not presented in the EAR, they can be calculated based on the yearly production projections presented in 4.1.3 and the number of wells projected in 4.1.2.

These productivity projections are considerably higher than the well productivity results from existing shale plays found by Berman and Pittinger (2011). In addition, calculations of well productivity over the 60 year period produce ultimate recovery figures for the New York portion of the shale play that, in the medium and high scenarios, exceed most scientific estimates of ultimate recovery (Coleman et al, 2011). Although the 29 Tcf low scenario (for 60 years) does not exceed geologist Terry Engelder's estimate for New York's portion of the Marcellus shale, the productivity projections seem particularly questionable considering that, "The Marcellus fairway in New York is expected to have less formation thickness, and because there has not been horizontal Marcellus drilling to date in New York the reservoir characteristics and production performance are unknown. IOGA-NY expects lower average production rates in New York than in Pennsylvania." (RDSGEIS, 5-139).

Moreover, as pointed out by a group of economists commenting on the EAR assumptions and methods (Barth, Kokkelenberg and Mount, 2011), the range of estimates of productivity is so large as to be meaningless. For example, estimates for well productivity during the 23rd year of production range from 600 billion to 3.6 trillion cubic feet, a variation on the order of 600%. Accuracy in these estimates is critical to derive estimates of tax and employment effects. As it stands, the estimates used in the EAR are no better than bloated "guesstimates."

The use of IOGA's estimates as the sole source of well productivity projections undermines the credibility and accuracy of the EAR and the RDSGEIS. The estimates of well productivity must be revised to more accurately reflect expert opinion on anticipated well productivity in the New York portion of the Marcellus shale. In addition, the RDSGEIS must be updated to reflect the Energy Information Administration's revised estimates of natural gas in the Marcellus shale based on the USGS analysis (Coleman et al, 2011).

The uncertainties associated with the productivity of extraction from the Utica shale must also be addressed, if Utica shale wells are to be included in the SGEIS analysis. In the EAR, the projections for the number of wells to be drilled include those for the Utica shale. There are significant uncertainties about the productivity of that play, the geographic variation in liquid content across that play, whether the well spacing and fracture treatment would resemble those for the Marcellus, and what technologies would be used in Utica shale development (Yost, 2011). These unknowns are significant and

indicate that Utica shale development may proceed differently than Marcellus shale development and utilize different technologies.

The unspecified inclusion of well numbers and productivity figures from the Utica shale also raises questions about the extrapolated employment, housing and tax implications that are attributed to Marcellus shale development.

The issues surrounding productivity are further complicated by the common practice of re-fracturing wells to increase pressure and productivity. If re-fracturing is practiced in New York Marcellus wells, communities will be repeatedly subjected to the environmental disruptions associated with heavy industry.

The uncertainties around and questions raised about long-term well productivity argue for modeling a shorter-term development and production cycle. At the very least, the competing evidence concerning well productivity and the cost of recovery should have been discussed in the RDSGEIS to qualify assumptions concerning the production cycle and estimated ultimate recovery.

A2. Impacts of the Uncertainties Associated with HVHF Gas Development

Evidence from Western shale plays indicates that the volatile pace and scale of natural gas development drives many environmental and social and economic impacts (Best, 2009; Jacquet, 2009; Headwaters Economics, 2010). Impacts directly affected by the pace and scale of drilling include:

1) Labor force needs and behavior. (How much of the workforce remains transient rather than becoming local? A local labor supply cannot develop if gas development is unpredictable.)
2) Demands placed on public services, including health facilities, public safety, and schools. (Can communities adapt over time or are there unpredictable rises and falls in demand?)
3) Community character impacts from increases in traffic, noise, construction disruption, and the transient population. (Do these increases roll out in a regular fashion with the expectation that disruptive “ramp-up” will end or are they unpredictable over a long period of time?)
4) Impacts on rural industries, such as tourism. (Can the scale of noise and traffic be predicted to occur only for a short period or are disruptive activities likely to recur over a longer period of time, for example, with re-fracturing of wells?)
5) Housing demand and cost. (Will there be periodic housing shortages with homelessness and lack of affordable housing for people on fixed incomes, potentially followed by excess housing supply and falling home values?)

To illustrate: As well pad construction begins in an area, jobs increase along with housing construction and business development. A transient population (in addition to transient industry workers) migrates to the area because of the prospect of jobs, increasing the demand for housing and services, including education and health. For a variety of reasons (price of natural gas, availability of higher value opportunities elsewhere, rig availability), natural gas development may drop off in the area within five-ten years of this initial “ramp-up.” Evidence from gas plays in Western states indicates that this drop-off may be sudden. In the wake of this drop in production and the number

of drilling rigs in the area, the transient population leaves and resident communities are left without jobs and revenue. Local governments may still be paying the public costs of ramping up to respond to the initial "boom." If conditions change (rigs become available, prices rise), the rigs may return to the area, causing another production "boom" with all of its attendant costs.

This pattern is described by Spelman (2009) and is associated with a reluctance of business (other than the gas industry) to invest in regions characterized by boom-bust economies. A contemporary example of such reluctance is contributing to the housing crisis in the Williston North Dakota Bakken Shale development. According to interviews conducted there: "Developers have been slow to build more apartments, largely because they got stung by the region's last oil boom that went bust in the 1980s." (MacPherson, 2011).

This volatile pattern is dramatically different from the scenario presented in the EAR and RDSGEIS. In both documents, communities are assumed to be impacted by a boom only once (during "ramp-up") and are gradually able to adjust to natural gas drilling. Many of the economic benefits that the RDSGEIS and EAR associate with natural gas development are predicated on this gradual, regular development scenario. For example, the RDSGEIS assumes that as the industry "matures" in the region, local residents will be trained and hired for drilling jobs. If, as has been the case with vertical drilling in New York State and in the Western US shale plays, development follows a more irregular pattern, then the higher paid technical jobs are less likely to evolve into stable local employment. In addition, the jobs in ancillary industries (retail and services) are likely to disappear and reappear as rigs leave and re-enter the region at unpredictable intervals. The RDSGEIS's use of a model built around regular, predictable development of the shale gas resource raises doubts about the projection of economic benefits based on that model.

A3. Hot Spots, Socioeconomic Impacts, and Public Costs

Contrary to the contention that the regularized development model "does not significantly affect the socioeconomic analysis" (RDSGEIS, 6-209), smoothing out the unpredictability and unevenness of development covers up many of the negative cumulative social and economic impacts that arise from the unpredictability of shale gas development. The RDSGEIS admits that steady, constant well construction is "unlikely" (RDSGEIS, 6-209), but it fails to analyze the implications of this admission and offers no description or evaluation of the adverse impacts of temporally and spatially uneven development.

In contrast with the model used in the RDSGEIS, natural gas development does not resemble a "manufacturing" process. Some wells will have long production phases; others will have dramatic declines in productivity after a relatively short period. Well productivity may be uniformly low across a region, or there may be long-term well productivity in particular "hot-spots." The question of how many wells will exhibit long-term productivity and where they will be located is unknown before exploratory drilling takes place and, even then, well productivity will be unpredictable.

The RDSGEIS admits that its socioeconomic analysis is based on average well productivity (RDSGEIS, 6-210), but the production process in natural gas (pace and scale) is not effectively captured using averages. The uncertainties in the geographic extent of drilling and the potential for intensive development in "hot spots" have

implications for social and economic impacts. For example, if drilling is concentrated in particular locations rather than rolled out uniformly across sub-regions of the landscape for 60 years (as is modeled in the RDSGEIS and EAR), wealth effects and tax revenues also will be concentrated in particular localities. The social and economic costs of spatially concentrated drilling, however, will be experienced across a much wider geographic area, because public services will be required in areas without HVHF development (and therefore not receiving tax revenues from drilling), but close enough to serve the transient population associated with the industry. There is no attempt to address this likely unbalanced distribution of positive and negative impacts in the RDSGEIS.

Finally, the RDSGEIS does not sufficiently model the resource depletion phase of the exploration, drilling, production, and resource depletion cycle and its implications for local and regional economies. Figure 6.13 (RDSGEIS, 6-215) shows the drop in direct and indirect employment following resource depletion. This depiction needs to be accompanied by analyses of how the resource depletion phase will be reflected in royalty payments and tax revenues.

A4. Socioeconomic Impact Analysis Can Accommodate the Uncertain Pace and Scale of Gas Development

If the impacts of volatility are to be mitigated, their prevalence in natural gas extraction regions needs to be acknowledged in the SGEIS. It is difficult to model the unpredictable pace and scale of natural gas production, but that difficulty is no excuse for ignoring adverse social and economic impacts arising from volatile and unpredictable development. Those impacts have been documented in relation to the phases of exploration, construction and drilling, production, and resource depletion, recognizing the company strategies that produce economic volatility in resource extraction regions (Jacquet, 2009; Kelsey, 2009; Sammons, Dutton and Blankenship, 2010).[1]

In cases where it is not possible to model specific cause-effect relationships (such as the relationship between well development and public costs), but where there is evidence of potential adverse impacts, those impacts should be recognized and documented. Sammons, Dutton and Blankenship (2010) take this approach in their report

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[1] From Sammons, Dutton and Blankenship (2010):

> Several recent studies address (social and economic) aspects of natural gas development in the western U.S. They include the *Northwest Colorado Socioeconomic Analysis and Forecasts* prepared for the Associated Governments of Northwest Colorado and the *Sublette County Socioeconomic Impact Study: Phase I Final Report* and *Phase II Final Report,* prepared for the Sublette County, Wyoming Board of County Commissioners. A third report, the *ExxonMobil Piceance Development Project Environmental Assessment - Socioeconomic Technical Report,* prepared by the authors for the U.S. Bureau of Land Management White River Field Office, assesses potential effects of a specific natural gas project in the context of ongoing large scale natural gas development in northeastern Colorado. A more recent journal article, *Energy Boomtowns & Natural Gas: Implications for Marcellus Shale Local Governments & Rural Communities,* published by the Northeast Regional Center for Rural Development, describes a model for impact assessment, presents a case study describing Sublette County's experience with large scale natural gas development and discusses some possible implications for Marcellus Shale development.

commissioned by the New York State Energy Research and Development Authority (NYSERDA) to describe socioeconomic impacts that can be anticipated with HVHF gas development. In addition, NYSDEC needs to quantify known social and economic costs even if their occurrence cannot be synchronized with their scenario model of development. This quantification can be accomplished through examination of comparable cases of impact, a standard method used in fiscal impact analysis (Kotval and Mullin, 2006).

B. NYSDEC's Analysis of Specific Socioeconomic Impacts: Model Assumptions and the Use of Representative Regions

The RDSGEIS presents only a fraction of the material contained in the EAR and acknowledges: "A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this RDSGEIS." (RDSGEIS, 6-207). This section identifies questions and concerns regarding the assumptions underlying the model used to predict impacts of HVHF development in New York State. These comments focus particularly on the use of representative regions to project impacts throughout New York State, including those for Utica shale gas drilling.

B1. The Use of Representative Regions

NYSDEC's use of a set of Southern Tier counties to represent all counties in New York that may experience HVHF shale gas drilling (EAR, 6-217) raises concerns about the representativeness of these counties. The EAR and RDSGEIS define three representative regions for the socioeconomic analysis, with Region A representing counties accounting for a high percentage of overall well development, Region B representing counties with about half the development of Region A, and Region C representing counties not expected to have much production but with a history of drilling. In the RDSGEIS, characteristics from a representative region are used to make assumptions about socioeconomic impacts in other New York State regions where drilling may occur. For example, tourism impacts are assumed to be minimal for all regions based on the continued presence of a tourism industry in Region C. The EAR and NYSDEC need to provide evidence (in industrial composition, growth rates, and population composition) to support the assumption that these counties are "representative" of all the counties that may experience drilling.

In addition, the EAR indicates that it addresses "local" impacts, but there is no analysis below the county scale. Analysis of differential economic impacts in urban and rural areas, for example, is critical to understanding the total economic impact picture. For example, counties in Region A in the EAR scenario analysis include both urban areas such as the Binghamton Metropolitan Statistical Area and rural areas where tourism and agriculture are the primary industries. Urban areas will garner more expenditures from natural gas drilling in the region, but are also likely to have negative impacts in the form of increased crime and demand for health services (because of their location in the urban areas). Rural areas will experience intense impacts on their small rural communities, including demand for housing and increases in road damage, as well as potential negative effects on agriculture and tourism. These local impacts, and how the costs and benefits will be distributed, need to be assessed separately.

B2. The Use of a RIMS Input-Output Model to Assess Social and Economic Impacts

A central component of the EAR is use of a Regional Industrial Multiplier System (RIMS) model developed by The Bureau of Economic Analysis. This type of model is useful for comparing different types of investments and for examining inter-industry linkages, but it has a significant drawback as the central model for the RDSGEIS analysis of socioeconomic impacts because it can only project economic benefits. It cannot measure or assess the costs of proposed gas development using HVHF or tell us anything about fiscal impacts.

The purpose of the model is to deduce direct and indirect economic impacts of new expenditures in a region. This type of model is very limited in the types of impacts it can assess. It is typically used to estimate some economic impacts, but is not useful to assess the wide range of social impacts that have been identified as occurring with HVHF shale gas drilling. So, for example, the model can be used to derive population increases and then, to crudely extrapolate potential housing demand. It cannot tell policy makers anything about the impact of housing demand on different population segments or on community character.

The results of this kind of model will always be positive because the model begins with the inflow of expenditures in the region. If the modelers had examined new expenditures flowing into the region's tourism or agricultural sectors those, too, would be positive. The model provided in the RDSGEIS does not allow us to assess opportunity costs, that is, to compare the economic impacts of shale gas drilling with those that might occur with increased investments and expenditures in other industries. This is important not only because shale gas drilling impacts are being considered in "isolation," but because investments in industries such as tourism and agriculture might decrease because of "crowding out" by HVHF activity (Christopherson and Rightor, 2011)

A model of this type is completely dependent on assumptions about the source of expenditures in the region. For example, in the case of HVHF gas development, the model is based on assumptions such as those about where the labor force hired in the drilling phase will spend the money they earn -- in the drilling region or in their home states? These assumptions are critical to the model results and should have been made available so that the accuracy of the model could be analyzed.

The presentation of the model results in the EAR is neither useful nor informative. Much of the text is devoted to tables that present mechanical calculations. These tables should have been relegated to an appendix and the body of the report used to lay out and support the assumptions that underlie the calculations.

In December 2011, the consulting firm that developed the EAR was asked to evaluate costs associated with gas development using HVHF in New York State. Because the RIMS input-output model and the associated scenario approach cannot address the costs of such development, the use of this approach rather than one that addresses costs as well as benefits needs to be justified and re-visited. In addition, because of its inability to address costs, the model does not provide information on impacts that require mitigation. Given the inadequacies of the EAR model and the significance of local and state costs to decisions about shale gas drilling in the state, revised EAR findings

regarding costs must be prepared and an opportunity for public review and comment on the revised EAR afforded before the SGEIS is finalized.

C. NYSDEC Analysis of Selected Social and Economic Impacts

This section comments on section 6.8 of the RDSGEIS, which assesses a selective subset of the many social and economic impacts anticipated with HVHF natural gas drilling. These include: (1) economy and employment, (2) population, (3) housing, (4) government revenue and expenditure, and (5) environmental justice. This section concludes with comments on material presented in the EAR that is not discussed in section 6.8, but which is relevant to the RDSGEIS findings regarding social and economic impacts.

C1. Economy and Employment

Employment. The oil and gas industry is not likely to be a major source of jobs in New York, because of the project-based nature of the drilling phase of natural gas production (rigs and crews move from one place to another and activities are carried out at each well) and because of its capital intensity (labor is a small portion of total production costs) (Jacquet, 2009). The emerging information on actual employment created in Pennsylvania in conjunction with Marcellus drilling shows much smaller numbers than industry-sponsored input-output models projected.

Although the industry points to years of drilling experience in New York, the oil and gas industry employed only 362 people in New York State in 2009 (0.01% of the state's total employment) (EAR, 3-7). 43% of those workers (157) were employed in Region C, the region where vertical natural gas drilling is most significant in New York. Wages for these workers constituted 0.04% of the wages in the two-county region with almost 4,000 active gas wells (EAR, 3-31).

The employment multiplier projected for New York State (2.1766) (derived from the model used in the EAR) is exceptionally high, especially for investment from a capital-intensive industry. (A 2.0 multiplier is considered generous by most regional economic analysts.) This underscores the importance of making the assumptions underlying the model transparent. For example, is the basis for the multiplier used an assumption that expenditures on real estate development resulting from the HVHF gas development will accrue disproportionately to New York state firms? If so, why? Because unrealistic and overly optimistic assumptions made in constructing the models may overstate economic benefits, assumptions underlying this RIMS model need to be available for scrutiny.

Finally, the employment figures presented in Table 4-8 are "full–time-equivalent" (FTE) jobs. These jobs do not correspond with what the ordinary person thinks of as a job – a person employed full-time to carry out certain tasks. They are a composite of part-time and full-time jobs that might be developed from the 410 job activities associated with constructing and drilling a well and from the subsequent production phase. These may not be new jobs, but existing jobs required to sustain industry activity. Finally, the EAR does not provide sufficient context for evaluating the employment impact of gas development using HVHF in the state. Projected employment in HVHF development should be compared with that in other New York industries, including tourism, to place the numbers in perspective. Projected increases in employment in these other

industries should be provided to enable comparison and to estimate costs and benefits of permitting HVHF gas development.

Impacts on other regional Industries. Having described in detail the modeled economic and employment growth from the gas industry, the RDSGEIS then mentions the potential adverse impacts on existing industries in the regions where natural gas development will occur. In a bare two paragraphs, the RDSGEIS admits:

> Conversely, some industries in the regional economies may contract as a result of the proposed natural gas development. Negative externalities associated with the [sic] natural gas drilling and production could have a negative impact on some industries such as tourism and agriculture. Negative changes to the amenities and aesthetics in an area could have some effect on the number of tourists that visit a region, and thereby impact the tourism industry. However, as shown by the tourism statistics provided for Region C, Cattaraugus and Chautauqua Counties still have healthy tourism sectors despite having more than 3,900 active natural gas wells in the region.
>
> Similarly, agricultural production in the heavily developed regions may experience some decline as productive agricultural land is taken out of use and is developed by the natural gas industry.

(RDSGEIS, 6-230).

In contrast with the pages of projected benefits from gas development, the RDSGEIS offers no detailed description and no quantitative analysis of the effects of HVHF development on existing industries and the associated impact on the state of New York's economy. This omission is particularly important for the counties defined in the EAR as "representative" because industries, including agriculture and tourism, are significant employers in those counties and are important to the overall economy of the State. There is no analysis of how the "crowding out" of existing industries may impact the regional or statewide economy or of the implications of the loss of industrial diversity to the long-term prospects for regional economic sustainability.

The inadequate assessment of the impacts on existing industries in the region that will be affected by HVHF gas development is problematic not only because the state does not have adequate information to assess costs and benefits of HVHF gas development, but also because negative impacts on industries such as tourism and agriculture, including dairies and wineries, will undermine state investments intended to support those industries. As discussed in detail below, given the importance of these industries in the state and regional economy, the evidence that they will be negatively affected by HVHF gas development should have been analyzed in detail and quantified when possible.

Tourism. The RDSGEIS makes no effort to quantify the value of tourist activities that may be adversely affected by gas development but rather dismisses any impacts as insignificant.

Nearly 674,000 New York jobs were sustained by tourism activity last year, representing 7.9% of New York State employment, either directly or indirectly. New York State

tourism generated a total income of $26.5 billion, and $6.5 billion in state and local taxes in 2010.

Tourism in the Southern Tier counties includes a wide range of activities, from visits to the Corning Glass Museum to hiking, hunting, and fishing in the rural areas. The Southern Tier Central (STC) Planning District, which includes Chemung, one "fairway" county (where significant natural gas drilling is anticipated because of the geologic formation) located in Region A in the RDSGEIS analysis, has published a study indicating that:

> In 2008, visitors spent more than $239 million in the STC region across a diverse range of sectors. The tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in the STC region that year. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income. In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue -- a tax benefit of $1,181 per household.

(Rumbach, 2011, page 1).

Tourism is thus a significant contributor to the counties in New York potentially impacted by HVHF gas development. The tourist opportunities and activities also contribute to the quality of life of local residents and attract companies in other sectors, such as manufacturing.

NYSDEC's use of Chautauqua and Cattaraugus Counties as the basis for contending that tourism will not be significantly impacted in New York is not persuasive. First, the evidence offered for the judgment that those counties have "healthy tourism sectors" (RDSGEIS, 6-231) consists of nothing more than the statement that: "In 2009 wages earned by persons employed in the travel and tourism sector in Chautauqua and Cattaraugus counties (Region C) were approximately $77.5 million, or about 3.0% of all wages earned in Region C" (NYSDOL 2009b*)* (see Table 3-37)" (EAR, 3-27). Without comparing Chautauqua and Cattaraugus over time with similar counties where natural gas development has not taken place, it is impossible to determine whether the tourism sector of the Region C counties has been negatively impacted by shale gas drilling.

The contention that those counties represent a tourism success story is contradicted by data presented in the EAR, which shows that from 2007 to 2009, Region C tourism employment declined 17%, and wages declined 13% (EAR, 3-28). While a portion of this decline might be attributable to the recession, there is no justification for describing waning tourism in the region as "healthy."

In addition, there is growing evidence regarding the negative effects of shale gas drilling on tourism in the counties where shale gas drilling takes place (Rumbach, 2011).

> Evidence from other shale plays in the Western U.S. indicates that natural habitat tourism (whether hunting, fishing, birding or hiking) may be disrupted for long periods of time and in some cases where infrastructure, such as compressor plants and pipelines, disrupts habitats, may be permanently altered.

(Sammons, Dutton and Blankenship, 2010). Negative impacts derive not only from the loss of habitat for outdoor sports, but also from the "crowding out" of tourism activities (because of increasing prices in the drilling region and the loss of hotel spaces to gas industry workers) and from the impact of regional industrialization on the tourism brand. For example, tourism centers in Upstate New York, such as the Finger Lakes wineries, may experience losses when tourists looking for a rural retreat find themselves driving through an industrial region with heavy truck traffic and shift their allegiance to quieter and more accessible vacation spots. In addition, the RDSGEIS does not assess the impacts on tourism from degradation of historical and cultural assets.

The EAR also conflates access to private recreational land for purposes of hiking, hunting, and fishing with the success of commercial tourism businesses. The relationship between personal recreational opportunities and natural gas development is presented as one of personal trade-offs in terms of land use. The negative impacts on the options of non-land owning recreationists are mentioned but not addressed (EAR, 4.58).

Rumbach's assessment of HVHF gas development on tourism is that:

> ….individual impacts are unlikely to have serious and long-term consequences, but without mitigation, cumulatively they could do substantial damage to the tourism sector. Examples of such impacts include strains on the available supply and pricing of hotel/motel rooms, shortfalls in the collection of room (occupancy) taxes, visual impacts (including wells, drilling pads, compressor stations, equipment depots, etc.), vastly increased truck and vehicle traffic, potential degradation of waterways, forests and open space, and strains on the labor supply that the tourism sector draws from. All told, the region's ability to attract tourists could be damaged in the long-term if the perception of the region as an industrial landscape outlasts the employment and monetary benefits of gas drilling.

(Rumbach, 2011, page 2).

The RDSGEIS fails to address the long-term costs associated with displacing business in existing industries, such as tourism, that provide economic diversity in the regional economy and thus increase its prospects for sustainability.

<u>Agriculture</u>. <u>Potential negative impacts on agricultural production and land use are noted, but their impact is not assessed nor are any mitigation measures proposed (RDSGEIS, 6-231). There is no analysis of whether and how HVHF gas development will affect sub-sectors of agriculture, such as dairy farming, which are of key importance in the New York economy</u>.

Milk and other dairy products account for more than half the total value of agricultural products sold in New York State, accounting for $2.2 billion in receipts in 2010. According to the US Department of Agriculture, New York ranks third in the US in production and sale of dairy products. Certainly the size and importance of this industry to the New York economy warrants a full analysis of how production and producers will be impacted by HVHF gas development. Instead, the RDSGEIS lacks an economic

assessment of how temporary and long-term agricultural costs and productivity will be affected by HVHF development.

Recent evidence from Pennsylvania indicates that agriculture and particularly dairy farming may be significantly affected by drilling activity. For example: "(Bradford) county's dairy herd has decreased over the last decade from 30,000 head in 2002 to just under 20,000 head today. Another 15 dairies have been sold since the beginning of the year (2011)" (Tomes, 2011). Although evidence from Pennsylvania is anecdotal, there is sufficient information to indicate that one of New York's major industries will be negatively affected by HVHF gas drilling.

Dairy farms are decreasing in areas with natural gas development both because some farmers have another source of income and because costs for dairy farmers are going up as a consequence of the impact of the drilling economy in the county. For example, competition for truck drivers is raising the cost for dairy farmers to transport their milk to processors. In addition to the impacts on the dairy farms themselves, the infrastructure that supports dairy farming in Bradford County is being affected. For example, an agricultural equipment dealer in the County has gone out of business because of an inability to hire and retain a workforce (Tomes, 2011).

There are also land use impacts that affect farmers, including impacts not only from the well pads, but also from the ancillary industrial facilities, such as "laydown yards" (operations and storage sites), pipelines, and compressor stations (Tomes, 2011).

The American Farmland Trust (2011) has submitted comments on the RDSGEIS that summarize its expert assessment of the impact on agricultural production in New York State:

> …the DEC's analysis of the impacts of drilling and hydraulic fracturing to agricultural land is inadequate and encourages specific analysis of the likely impacts of such activities to agricultural land resources. The SGEIS analysis should consider the scale of farmland likely to be converted by both direct drilling activities and the off-site drilling support services and other types of residential and commercial development that is anticipated as a result of natural gas drilling. In addition, it should consider the impacts of such activities to agricultural land values and on the ability of New York farmers to maintain their competitiveness in a global economy.

Upstate New York is currently experiencing a resurgence in its food processing industry, and the State Agricultural and Markets Program has a stated policy of encouraging more dairy production in the state. In July 2011, the State of New York provided $16 million in incentives to a dairy processing company in Chenango County in Central New York. According to a statement by Governor Cuomo: "Agro Farma's expansion in Chenango County will create hundreds of new jobs and increase the demand for milk from New York dairy farms," (press release available at: http://www.governor.ny.gov/press/07212011DairyProductsCompany).

The support from New York's Empire State Development Corporation reflects the significance of this industry to the regional and state economy. A full economic assessment of potential impacts to this industry is warranted. This assessment should include labor costs (from competition for truckers, for example) and impacts on specialty

agricultural producers, such as organic farmers. New York State has the fourth largest number of organic farms in the U.S.

The Finger Lakes wineries, combining agriculture and tourism, are another important subset of New York industries that may also be affected by HVHF gas development in Upstate New York. New York State ranks third nationally in grape production. Tourists visiting the wineries may not want to drive through industrial development and its associated truck traffic in order the reach the wineries, even if the wineries are not locally impacted by the drilling process. Given the importance of this and other sectors of New York's agricultural industry to the Upstate New York "brand" and the investment of State resources to build the industry, the SGEIS needs to separately assess the impacts on this industry and develop mitigation policies to address the negative impacts identified.

Manufacturing. Finally, the RDSGEIS and the EAR focus exclusively on impacts to agriculture and tourism because the use of land by those industries potentially competes with use of land for gas development. Focusing on that competition may make sense for the largely rural representative regions defined in the EAR, but it does not make sense for representative regions with more diversified economies, including substantial manufacturing. A report by the New York State Comptroller's office in 2010 shows that the Southern Tier has 14% of Upstate manufacturing. Manufacturing should be included in the assessment of impacts on existing industries, because of its significance in Region A and because gas development will affect the labor supply and industry wage rates in counties where manufacturing plays a significant role in the economy.

C2. Population

The RDSGEIS and EAR do not address population impacts on community services, such as schools and health, but only population as it relates to employment and the labor market. There was no attempt to look at actual population trends in counties with significant gas drilling and whether they reflect a decline in economic diversity that makes population levels less sustainable. An analysis of the long-term population trends in shale gas drilling counties in the US is necessary to determine the impact of HVHF gas development on New York counties. A projection based on labor demand is not sufficient.

The EAR assumes that, for the first 30 years, the population increases in counties that "host" natural gas drilling will be modest. It notes, for example:

> [A]ctual population impacts may also be less than what is described in the following section because currently unemployed or underemployed local workers could be hired to fill some of the construction and production positions, thereby, reducing the total in-migration to the region.

(EAR, 4-59).

By focusing only on population changes directly related to gas industry employment, the RDSGEIS avoids addressing the potential for long-term population decline beyond the loss of industry workers. Many areas with significant natural gas drilling lose population over time. That has been the case with Chautauqua and Cattaraugus counties (Region C) in New York.

In addition, the RDSGEIS assumes a gradual (rather than disruptive) integration of the unemployed population in the region and of transient workers into the labor force required by the industry. Experience from other states, however, contradicts the assumption of easy integration of the resident workforce and of newcomers to the regional labor force: "In areas of Pennsylvania where Marcellus shale drilling activity is occurring, it has been difficult at times to accommodate the influx of new workers" (Kelsey, 2011). The potential for a low-skilled, transient workforce to migrate into the area is not considered, although there is evidence from Western shale plays that this occurs, and is particularly likely with high national unemployment rates.

> [B]ecause labor markets are imperfect, [and] the availability of a relatively large number of jobs may result in an influx of job seekers, some of whom lack necessary skills and qualifications and may be relatively indigent. To the extent that indigent job seekers are unable to find jobs or do not have resources to secure housing and transportation to work; they can become a burden for local human service agencies. This situation can be exacerbated by weak economic conditions in other parts of the state or country.

(Sammons, Dutton and Blankenship, 2010, page 13).

The RDSGEIS fails to address this evidence of adverse economic impacts.

C3. Housing and Property Values

<u>The potential impacts on the housing supply, housing costs, and housing financing are inadequately assessed in the EAR. In addition, the social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed.</u>

The report assumes that the current housing stock would be used to house any workers who move to the production region on a "permanent" (more than one year) basis (EAR, 4-107 (concluding "the impact on the supply of permanent housing units would be negligible at the statewide level during the production phase")). Given the quality and age of the housing stock in the region, evidence from Pennsylvania indicates that it is likely that there will be a demand for new single-family housing (Kolb and Williamson, 2011). This new housing stock will create new and additional construction jobs, increasing population pressure, accelerating the "boomtown" phenomenon. This housing may also contribute to sprawl around urban population centers such as Binghamton. When drilling ceases, either temporarily or permanently, the value of this new housing is likely to plummet (Best, 2009).

With respect to temporary housing, the EAR (EAR, 4-111) admits:

> In areas of Pennsylvania where Marcellus shale drilling activity is occurring, it has been difficult at times to accommodate the influx of new workers (Kelsey 2011). There have been reports of large increases in rent in Bradford County, Pennsylvania, as a result of the influx of out-of-area workers (Lowenstein 2010). There have also been "frequent reports" of landlords not renewing leases with existing tenants in anticipation of leasing at higher rates to incoming workers, and reports of

> an increased demand for motel and hotel rooms, increased demand at RV camp sites, and increases in home sales (Kelsey 2011). Such localized increases in the demand for housing have raised concerns about the difficulties caused for existing local, low-income residents to afford housing (Kelsey 2011).

If communities add substantial temporary, short-term housing or single-family housing to accommodate development-phase workers, surplus capacity may exist in all these types of units after development is completed. Based on evidence from other shale gas plays, all of these adverse impacts (initial housing shortage, surplus supply if rigs leave temporarily and depressed value in some areas) may occur (Best, 2009; Sammons, Dutton and Blankenship, 2010).

The EAR (EAR, 4-111) also acknowledges the potential impact of the volatility of the production cycle on the housing market and property values:

> The demand for housing, both temporary and permanent, would be expected to change over time. The demand for housing would be the greatest in the period during which the wells in an areas are being developed, and demand would decline thereafter. This would create the possibility of an excess supply of such housing after the well development period (Kelsey 2011). If well development in a region occurs in some areas earlier than in others, then housing shortages and surpluses may occur at the same time in different areas within the same region.
>
> The natural gas market can be volatile, with large swings in well development activity. Downswings may cause periods of temporary housing surplus, while up-swings may exacerbate housing shortages within the regions.

A recent study of the impact of HVHF gas development in Pennsylvania indicates that impacts on the housing supply are significant, especially for people at the economic margins (Williamson and Kolb, 2011). These impacts pose environmental justice concerns and require mitigation strategies.

With respect to impacts on property value, the EAR authors found that having a well on a property was associated with a 22% <u>reduction</u> in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. Thus,

> …not all properties in the region would increase in value, as residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights (EAR, 4-114).

The EAR authors attributed the positive impact on property values of having a well located within 550 feet of a property to <u>the prevention of further gas well development</u> in that area due to a spacing order and setback conditions that prevented well drilling close to existing wells.

The assertion in the EAR that property owners in the drilling region would see an overall increase in property values is based on increased demand and economic activity. Evidence from Pennsylvania and from Western Shale plays indicates that this demand may not occur in the county or locality where the drilling is occurring (Patton et al, 2010).

The EAR's assumption of recovering property values after the completion of HVHF gas development does not take into account the potential for re-fracturing of wells to increase their productivity or the effects of waves of development in which drilling moves in and out of an area. The prospect of industrial activity is what drives down investment in regions open to boom-bust development and also negatively impacts property values (Spelman, 2009). A more definitive analysis of impacts of on property values, including mortgage availability, in regions affected by drilling is needed.

C4. Government Revenues and Expenditures

The RDSGEIS assumes, based on the RIMS model, that economic benefits from HVHF gas development, presumably including benefits to revenue, will be substantial, but there is no fiscal impact analysis or cost-benefit analysis to substantiate that assumption. A fiscal impact analysis is required, given that:

(1) Many purchases by drilling companies are tax exempt (EAR, 4-116).

(2) Costs to the state that will reduce or offset tax revenues are not calculated. For an example of this problem, see the discussion of rail infrastructure in the RDSGEIS section on transportation impacts. The provision of tax rebates to railroad companies and to industry facilities represent lost revenue to the State and the locality. The EAR admits that in addition to tax benefits, "such as expensing, depletion, and depreciation deductions," which reduce taxable income, "New York State offers an investment tax credit (ITC) that could substantially reduce most, if not all, of the net income generated by these energy development companies" (EAR, 4-115 to 4-116).

(3) Substantial negative fiscal impacts are detailed in the EAR that are not quantified or fully acknowledged in the SGEIS:

> High-volume hydraulic fracturing operations would also result in some significant negative fiscal impacts on the state. The increased truck traffic required to deliver equipment, supplies, and water and sand to the well sites would increase the rate of deterioration of the state's road system. Additional capital outlays would be required to maintain the same level of service on these roads for their projected useful life. Depending on the exact location of well pads, the state may also be required to upgrade roads and interchanges under its jurisdiction in order to handle the additional truck traffic. The potential increase in accidents and potential additional hazardous materials spills resulting from the increased truck traffic also would require additional expenditures. Finally, approval of transportation plans/permits would place additional administrative costs on the New York State Department of Transportation (EAR 4-116).

There are now numerous studies available to calculate road damage, and the counties in the "fairway" in New York State have undertaken baseline studies that would enable

accurate calculation of the costs of road damage (Randall 2011). There is plenty of expertise available in the state to draw on, including Cornell Local Roads program, which has completed a thorough analysis of the kind of damage and what it would cost to repair.

The EAR also recognizes additional public costs associated with Marcellus shale gas development:

> Additional environmental monitoring, oversight, and permitting costs would also accrue to the state. In order to protect human health and the environment, New York State would be required to spend substantial funds to review permit applications; to ensure that permit requirements were met, safe drilling techniques were used, and the best available management plans were followed; and to provide enforcement against violations. In addition, the state would experience administrative costs associated with the review of well permit applications and leasing requirements and enforcement of regulations and permit restrictions. All of these factors could result in significant added costs for the New York State government.
>
> The New York State Department of Health would also incur additional costs due to the need to provide additional technical support and oversight services to local governments that would monitor water quality in local drinking water wells (EAR, 4-116).
>
> In addition to the positive fiscal impacts discussed above, local governments would also experience some significant negative fiscal impacts as a result of the development of natural gas reserves in the low-permeability shale. As described in previous sections, the use of high-volume hydraulic-fracturing drilling techniques would increase the demand for governmental services and thus increase the total expenditures of local government entities. Additional road construction, improvement, and repair expenditures would be required as a result of the increased truck traffic that would occur. Additional expenditures on emergency services such as fire, police, and first aid would be expected as a result of the increased traffic and construction and production activities. Also, additional expenditures on public water supply systems may be required. Finally, if substantial immigration occurs in the region as a result of high-volume hydraulic fracturing operations, local governments would be required to increase expenditures on other services, such as education, housing, health and welfare, recreation, and solid waste management to serve the additional population (EAR, 4-138).

The RDSGEIS mentions public costs associated with the increased demand for community social services, police and fire departments, first responders, schools, etc., but makes no attempt to calculate the costs and consider them in the context of a fiscal impact assessment. Experience in other shale gas plays demonstrates that these costs are likely:

> Natural gas development and production-related activities and the incremental population associated with those activities will generate

> demand for the full range of local government facilities and services and for some state government services. For example, during exploration and moderate stages of development, demand is usually limited to law enforcement, emergency response, emergency medical and road and highway maintenance and traffic control. Traffic, vehicle and industrial accidents and issues associated with a single-status, predominately working-age male workforce are the primary drivers associated with emergency response and law enforcement increases. Because many workers are temporary, and do not have local general purpose health care providers, they commonly use hospital emergency rooms for what would be otherwise be routine health care visits.

(Sammons, Dutton and Blankenship, 2010, page 19).

This knowledge regarding public costs and fiscal impacts should have been reflected in the RDSGEIS. These costs may occur even if the amount of commercially extractable natural gas does not reach projected levels. They need to be calculated both in terms of the baseline costs that are likely to occur with <u>any</u> drilling activity and in relation to varying levels of drilling activity.

Addressing the variability is important because there are distinct community character impacts attributable to large-scale development that have been identified and documented in other shale plays.[2] For example:

> …some areas that experience large scale development have reported substantial increases in a variety of crime and social problems including alcohol and drug-related offenses, traffic offenses, disturbances, assaults and domestic conflicts. Although some increases in crime and social problems would be anticipated to accompany any increase in population, some researchers have also attributed the increased levels of crime and social problems to the temporary and transient nature of the workforce and their living conditions. There has been some debate in the social impact assessment literature about whether or not crime and other adverse social indicators increase at higher rates in communities experiencing large-scale development than average rates for all communities. But the implications are clear that increases in crime and social problems are likely with large-scale development, even if they are proportionate to the increase in the numbers of people working and living in affected communities.

(Sammons, Dutton, and Blankenship, 2010).

Given the scale of development being projected, the thresholds for community costs and

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[2] *See* Sublette County Socioeconomic Impact Study Phase I Final Report. Ecosystem Research Group. , January 2008. Pages 54 – 58 and Index Crimes, Arrests, and Incidents in Sublette County 1995 to 2004: Trends and Forecasts, Prepared by J. Jacquet. Sublette County, Wyoming, April 2005, *available at:* http://www.sublettewyo.com/DocumentView.aspx?DID=351; Local Social Disruption and Western Energy Development: A Critical Review, Wilkinson et.al. Pacific Sociological Review Volume 25. July 1982. *available at:* http://www.sublettewyo.com/archives/42/Local_Social_Disruption__Critical_Review_Response_and_Commentary [1]. pdf.

adaptation to the impacts related to population increase or demand for services (administrative, school, health, public safety) must be addressed by the SGEIS. Evidence from Pennsylvania indicates that ability to adapt to these community social and economic impacts is critical to short-term and long-term community well-being (Kolb and Williamson, 2011; Kelsey, 2010, 2011).

(4) Costs will vary with the nature of population increases driven by the permitting of HVHF gas development. For example, indigent job seekers unable to find jobs and without resources to secure housing or transportation to work can become a burden for local human service agencies. This situation may be exacerbated by weak economic conditions in other parts of the state or country.

An example of this phenomenon is documented in a study carried out by Guthrie Hospital/Troy Community Hospital in Bradford County, Pennsylvania, where impacts from HVHF gas development in the county have significantly increased demand for health services (Covey 2010). The hospital is treating a new non-English speaking clientele and has had to hire translators. They have also had to purchase new equipment and have experienced a significantly increased demand on their emergency room services. The new demand affects not only the bottom line of providers, but also the availability of and access to health care for residents of the region in which drilling is occurring.

(5) There is no analysis of the expected lag between immediate costs and anticipated revenues. This lag may be 2-3 years, during which communities will be faced with significant public service costs.

(6) A tax profile needs to be presented over time, not one for a single year, in order to understand how natural gas drilling has fiscally impacted Region C, where most wells are currently located and where wells have increased.

C5. Environmental Justice Impacts

A section on Environmental Justice, included at the end section 6.8 of the RDSGEIS, notes that well permits are currently exempt from screening under NYSDEC Commissioner Policy 29, Environmental Justice and Permitting (CP-29) (RDSGEIS, 6-263). NYSDEC suggests that a drilling permit applicant could, “when necessary,” conduct a GIS analysis to identify potential environmental justice areas. The RDSGEIS should set forth criteria to determine when such an analysis would be “necessary” and should include the requirement in standard permit conditions or regulations. Moreover, given the known housing impacts of gas development on low-income populations, efforts to mitigate significant adverse environmental justice impacts must include not only the “additional community outreach activities” required in the RDSGEIS, but also substantive measures to prevent dislocation and homelessness.

II. Additional Economic Impacts Identified in the EAR But Not Addressed in the RDSGEIS

The RDSGEIS presents only a fraction of the material contained in the EAR and acknowledges: “A more detailed discussion of the potential impacts, as well as the

assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this SGEIS" (RDSGEIS, 6-207). This section comments on material presented in the EAR that is not discussed in section 6.8, but which is relevant to the RDSGEIS findings regarding social and economic impacts.

A. The Distribution of Impacts of HVHF Gas Development in New York State

The socioeconomic impact analysis should systematically describe the geographic distribution of impacts. In New York, as is explained below, the creation of high-paying jobs as a result of expenditures in industries outside the extraction industry is likely to occur outside the production region. This is important because regions where natural resource extraction takes place (and especially rural regions with little economic diversity) have been found to end up with poorer economies at the end of the resource extraction process (Best, 2009; Sammons, Dutton and Balnkenship, 2010). Mitigation measures need to be identified to address long-term costs to the rural counties where extraction will be concentrated.

The EAR calculates the impact of a $1 million increase in the final demand in the output of the oil and gas extraction industry on the value of the output of other industries in New York State (EAR, 3-6). The EAR then makes a series of statements concerning where the economic benefits of HVHF development are expected to occur. For example:

> The proposed use of high-volume hydraulic fracturing would have a significant, positive impact on employment in New York State as a whole and in the affected communities. However, the distribution of these positive employment impacts would not be evenly distributed throughout the state or even throughout the areas where low-permeability shale is located. Many geological and economic factors would interact to determine the exact locations where wells would be drilled. The location of productive wells would determine the distribution of impacts.

(EAR, 4-46; emphasis added).

The location of wells is, however, only one factor affecting the distribution of economic impacts in New York State. Many wells are drilled in rural areas with no or very limited commercial services near-by. If that is the case, then the economic impacts (in the form of expenditures by drillers and companies) will not occur close to the drilling site. Some will occur in centers – perhaps across a municipal or county line – where there are stores and restaurants that the drilling company employees use for meals and supplies. Some economic impacts will occur in far away places, such as New York City, where the drilling company can buy specialized services, such as tax accounting and legal services, to meet their business needs.

This potentially broad distribution of economic impacts is reflected in the multipliers reported in the EAR as follows:

> As anticipated, the direct effect employment multiplier for the State of New York (2.1766) was substantially larger than the multipliers for the individual regions, which had direct-effect employment multipliers of 1.4977 in Region A, 1.3272 in Region B, and 1.4357 in Region C (USBEA

2011a, 2011b, 2011c, 2011d). (EAR, 4-19).

These multipliers are affected by purchases by the gas drillers from other industries in the economy. In this case, the RIMS model used in the EAR indicates that three largest industries in which purchases will be made (and additional employment created) are: (1) real estate and rental; (2) professional, scientific, and technical services; and (3) management of companies). We can anticipate that purchases from these industries would have a strong effect in New York State as a whole because these industries have a strong presence in New York State.

What the multipliers also tell us, however, is that the jobs indirectly created by purchases of goods and services by the natural gas developers are not likely to be located in the counties where HVHF gas development occurs. Multipliers tell us how strong the industry is in a region or state. Higher multipliers indicate that those businesses that the oil and gas industry is likely to purchase goods and services from are present. Lower multipliers indicate a small industry presence and thus a lower likelihood of purchases in that geographic area. So, for example, a natural gas development company would employ professional services as a consequence of expanding drilling in Chautauqua County, but is likely to go to New York City to purchase those services because they are more likely to be available in New York City. Companies providing professional services in New York City are more likely to stay there rather than move to the Southern Tier because they have more opportunities to attract diverse industries to their specialized services in New York City than in Elmira or Jamestown.

If the EAR seeks to project the impact of expenditures on the regions in the state likely to be affected by HVHF gas development, it needs to disaggregate these impacts to show what proportion of the impacts in the three largest sectors (real estate and rental; professional, scientific, and technical services; and management of companies) is actually likely to occur in the representative regions. Although the authors assert that as the natural gas industry grows, more of the suppliers would locate to the representative regions and less of the indirect and induced economic impacts would leave the regions, no evidence is presented to substantiate this assumption. This assumption contravenes economic knowledge about agglomeration economies and company location behavior, which indicates that specialized services will remain in higher order centers (like New York City) and not re-locate to counties, especially rural counties, where drilling is occurring. The more likely outcome is indicated by a study of the impact of gas drilling on Western State economies, which found that natural gas drilling may have positive fiscal impacts at the state level, but negative fiscal impacts for the regions in which it occurs (Headwaters Economics, 2011).

B. The Distribution of Economic Impacts in New York Versus Those in Other States

Nationally, Texas and Oklahoma are the major beneficiaries of natural gas development, wherever production takes place in the United States. According to *Mine K. Yücel and Jackson Thies of* the Dallas Federal Reserve (2011): "An increase in oil and gas production **anywhere** benefits the state (of Texas) and its energy sector, which provides oilfield machinery and energy services to the rest of the world." See also subsection C, below. Nevertheless, because of its capital intensity, natural gas drilling does not have a large employment impact, even in Texas. Gas development thus plays a minor role in the economies of even these resource extraction states.

C. The Distribution of Highly-Skilled Jobs

Petroleum engineers are listed as one of the most common occupations in the oil and gas industry (EAR, 3-8, Table 3-10). The geographical analysis of this occupation by occupational employment statistics indicates that the states with the highest employment in this occupation are Texas, Oklahoma, and Louisiana. In 2010, the total U.S. employment of petroleum engineers was 28,210, of which 15,510 were employed in Texas, and 10,380 of those worked in the Houston metropolitan area. Thus, even in Texas, the employment in this occupation is concentrated in the Houston metropolitan area, not in the drilling areas.

The likely distribution of highly paid occupations is demonstrated by the Bureau of Labor Statistics (BLS) Occupational Employment Statistics Data on one of the most numerically significant skilled occupations, that of petroleum engineer. According to the BLS, only a fraction of petroleum engineers (in the hundreds) are employed in non-metropolitan areas in the U.S. (BLS, 2010). This data, too, suggests that the rural areas of New York that are likely to experience the most intensive gas development will not see an increase in highly skilled and highly paid jobs related to the oil and gas industry.

III. Inadequacy of Proposed Mitigation Measures

A. Mitigation Measures That Address Potential Impacts Related to Volatility in the Pace and Scale of Drilling Should Be Required

The mitigation chapter of the RDSGEIS implies that negative impacts will be mitigated through the permitting process and a secondary level of review triggered by the operator's identification of inconsistencies with comprehensive land use plans. The measures identified are only advisory. The RDSGEIS proposes no requirements to mitigate adverse socioeconomic impacts in this process.

Mitigation measures should be developed that would require operating companies to submit plans for exploration and development in a county or counties to county planning offices for review of cumulative impacts and mitigation (for example truck traffic routing), a model used in Western U.S. drilling regions (Headwaters Economics, 2011). This assessment is also completed for National Environmental Policy Act compliance when development proceeds on public lands.

Because the RDSGEIS acknowledges that the pace and scale of development are difficult to ascertain until exploration and production begin to proceed, it is critical that a permit and regional Plan of Development (POD) review process be set up that alerts local officials to the need for long term planning for land use, schools, public safety and public health. The POD, outlining the pace, scale, and general location in which development will occur, enables local government to anticipate and develop strategies to mitigate cumulative impacts (Sammons, Dutton and Blankenship, 2010). The near-term projections of development activity should include all secondary facilities (e.g., water extraction, waste disposal, pipeline construction) in the area to be affected.
A POD would allow communities in that region to prepare for the disruption and negotiate the least disruptive and damaging development plan.

Another mechanism for reducing the unpredictability and uncertainty of natural gas production at the regional scale is being developed by the Nature Conservancy with pilot projects in the Western States and planned in Pennsylvania (see Kiesecker et al, 2010). Their objective is a science-based, landscape-scale approach to Marcellus gas development that will secure measurable conservation outcomes, while enhancing industry's ability to operate in an environmentally sensitive and cost-efficient manner. To be enforceable, this cooperative approach, based on a partnership between the operating company and local public officials, needs to be codified in a binding agreement. Partnerships of this sort may be useful, but they cannot serve as mitigation for significant adverse socioeconomic impacts unless they are mandatory.

B. Mitigation Should Address Housing and Urban Development Impacts, Including Sprawl and Excess Substandard Housing

Evidence from Pennsylvania and Western shale plays indicates the likelihood of negative impacts on the quality of the temporary and permanent housing stock, a high rate of homelessness for extensive periods, and displacement of low income people from affordable housing. Given the presence of small cities in the region, mitigation measures should include required assistance to cities in the affected region to encourage new housing development in already-developed urban areas and the development of temporary housing that could be transformed to other uses once the influx of transient workers resides. Mitigation measures should also address the impacts of the loss of affordable housing units in the region.

C. Mitigation Should Address Long-Term Social and Economic Impacts

The RDSGEIS and the EAR describe significant adverse social and economic impacts, such as those produced by the volatility of natural gas development on the housing market of regions where development occurs. No mitigation strategies are recommended to alleviate long-term costs that are reasonably assumed to be associated with natural resource development, including HVHF development. Mitigation strategies directed at these long-term costs to the affected regions need to be developed and described in the SGEIS. Mitigation strategies also need to be developed to address the resource depletion phase of the exploration, drilling, development and resource depletion process. In this phase, population and jobs leave the region and tax revenues may be insufficient to pay for the capital investments made to serve the population influx during the drilling and production phases of development. Mitigation strategies should include policies to prevent negative impacts on existing industries, including agriculture, tourism and manufacturing.

D. Mitigation Should Require That Monitoring Reports Projecting Industry Development Plans Be Prepared by the State in Cooperation with Industry and Filed Semiannually

As development activities begin and progress, the information provided in initial projections should be required to be confirmed or revised on a semiannual basis. Information provided in the semiannual assessment and projection should include: (1) employment for each activity; (2) identification and location of contractors; (3) demographic characteristics and residence of employees who will be working in the region. This information is critical to forecasting and meeting housing and service demands.

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Attachment 6

Meliora Design, LLC.

Technical Memorandum

Review and Analysis of the

Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

and the

Draft New York State Department of Environmental Conservation SPDES General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing

January 10, 2012

Prepared for:

Natural Resources Defense Council

New York, New York

Prepared by:

Michele C. Adams, P.E. Water Resources Engineer
and
Ruth Ayn Sitler, P.E. Water Resources Engineer
Meliora Design, LLC
100 North Bank Street
Phoenixville, PA 19460

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Introduction

This memorandum reviews both the *Revised Draft Supplemental Generic Environmental Impact Statement* (RDSGEIS) *on the Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs* and the Draft *New York State Department of Environmental Conservation SPDES General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing* (SPDES HVHF GP). The focus of this memorandum is the potential impacts on surface water resources that result from land disturbance and alteration, including impacts related to increased erosion and sedimentation, as well as impacts that result from increased and altered stormwater discharges. The review of both the RDSGEIS and the Draft SPDES HVHF GP are co-dependent, as the Department has indicated that general or (substantially similar) individual SPDES permit coverage will be the primary means of regulatory oversight for HVHF operations (and presumably for other low-volume hydraulic fracturing activities, although this is not explicitly stated).

The land disturbance associated with HVHF construction activity has the potential to negatively impact surface water quality in the same manner as other land disturbance activities, as discussed in Attachment A, and the lack of a local government land development review process increases the potential for greater water quality impacts through the increased disturbance of steep slopes, sensitive areas, proximity to unmapped headwater streams, etc. Furthermore, the land disturbance nature of HVHF operations results in a dispersed industry across a wide area, with a large (and unknown) number of stream crossings and an increase in road traffic and gravel road construction. The documented water quality impacts of roads (including gravel roads) are also discussed in Attachment A.

Summary of Key Findings:

The RDSGEIS provides only a very brief generic discussion on the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). While the RDSGEIS acknowledges that this land disturbance has potential for water quality impacts, and the Department has made a positive determination that a SPDES permit is required, the RDSGEIS provides little specific discussion or consideration of the land disturbance and surface water quality impacts. Specifically:

- The RDSGEIS makes no attempt to evaluate the cumulative impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the 1992 GEIS, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts with little industry-specific consideration, and no consideration of total or cumulative impacts. **A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential for a full environmental impact analysis, and to inform any determinations by the Department on the appropriate regulatory permitting requirements.**
- The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream

crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically not included in the Draft SPDES HVHF GP. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current Department regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. **The RDSGEIS should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed Department requirements to regulate and mitigate these impacts.**

- The RDSGEIS does not adequately address private well setbacks, road spreading of brine, gather lines, fueling areas, on-site disposal of drill cuttings, and acid rock drainage. Each of these has the potential to significantly impact and impair water quality. **The RDSGEIS should provide additional information regarding each of these impacts, specifically with regard to landowner notification of well setbacks, cumulative impacts of road spreading of brine, minimizing stream crossings with gather lines, addressing the non-stationary status of fueling areas, and consideration of ARD impacts from disposal of drill cuttings.**
- With the exception of watersheds that serve as unfiltered drinking water supplies and receive Filtration Avoidance Determination (FAD) status, the RDSGEIS and SPDES HVHF GP do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support that proposed setbacks are adequate to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep

slopes). **The RDSGEIS should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.**

- Even if the proposed setbacks discussed in Chapter 7 were adequate, they are not clearly coordinated with the EAF requirements in Appendices 4, 5, 6 and 10 and the Draft SPDES HVHF GP mapping and documentation requirements (and the SPDES HVHF GP is presumably the regulatory mechanism for compliance). **The Draft SPDES HVHF GP mapping requirements must be at a scale and level of site-specific detail to accurately reflect the required information, and SPDES mapping requirements must be consistent with those identified in the RDSGEIS.**
- The RDSGEIS fails to provide a clear and accessible process for public and local government access to site specific HVHF activity information. At the same time, DEC expects local governments to provide notice to the Department if a proposed HVHF activity is not in compliance with local zoning or land use regulations. This approach puts the regulatory burden on a local government that wishes to challenge a proposed permit application while simultaneously failing to provide local government with access to the necessary information. **The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public,** with supporting public access to all information regarding proposed land disturbance activity, and reasonable timeframes and processes for comments and addressing of concerns.
- The Draft SPDES HVHF GP is essentially a compilation of the Department's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. Based on the very limited discussion of land disturbance and surface water impacts in the RDSGEIS, it is uncertain whether a general permit process will be

sufficient to protect water quality. It is also not clear that an industry that is NOT subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF operations.

- The general permit process does not provide a timeframe (and process) for public review, comment, and objection to any or all parts of a general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the Department and meeting minimum performance requirements. There is no opportunity for public access to information or appeal of permit coverage. **It is essential that the SPDES HVHF GP provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site *before* general permit coverage is granted. It is essential that the permit coverage timeline be adjusted to provide for public comment and appeal.**

Comments on the RDSGEIS

As previously indicated, the discussion in the RDSGEIS on the total land use impacts and associated water quality impacts as a result of both land disturbance during construction and post-construction stormwater management is extremely limited.

Comment 1:

Chapter 5, Natural Gas Development & High-Volume Hydraulic Fracturing. Section 5.1 of the RDSGEIS discusses the impacts of Land Disturbance, including Access Roads, Well Pads, Utility Corridors, and Well Pad Density. See pages 5-6 through 5-31. Estimates of land disturbance associated with each of these well drilling activities are provided but total or cumulative land disturbance is not addressed.

Comment 2:

Section 5.1 *Land Disturbance* identifies a number of types of land disturbance activities associated with HVHF including utility corridors (including gathering lines), compressor facilities, and access roads associated with compressor facilities. The Draft HVHF SPDES permit (Part III.A.3) does NOT address construction of gathering lines, compressor facilities, or the access roads associated with compressor facilities.

Recommendation: The RDSGEIS must provide a process for regulation and mitigation of the land disturbance impacts associated with gathering lines, compressor facilities, and the access roads associated with compressor facilities. The RDSGEIS cannot identify the SWPPP as "*the principal control mechanism to mitigate potential significant adverse impacts from stormwater runoff*" (Section 7.1.2 SGEIS) without providing for adequate management requirements for all HVHF activities in the Draft SPDES HVHF GP.

Further discussion in Section 5.1 provides some analysis of disturbance areas associated with gathering lines, compressor stations, and access roads to

compressor stations, but specific consideration of the impacts of these activities is not discussed in Chapter 6, and specific recommendations to reduce the impacts of these components (such as co-locating gathering lines along well pad access roads) is not provided in Section 7 or the Draft HVHF SPDES permit.

Comment 3:

Section 5.1.1 *Access Roads* indicates that roads may be placed across ditches, but does not discuss the construction or widening of access roads that cross streams or wetlands. The potential impacts of such crossings are not discussed in Section 6.1.2, *Stormwater Runoff* or other portions of Section 6, nor are the mitigation measures for road crossings of streams and wetlands addressed in Section 7.1.2 *Stormwater.* Setbacks for roads from streams and wetlands are not specifically addressed in either Chapter 7 or the Draft HVHF SPDES permit, nor are requirements for stream and wetland crossings provided. It is not clear as to whether an Article 15 Stream Disturbance Permit from the DEC will be required for HVHF projects and what compliance might entail. It is noted that Photos 5.1 and 5.2 of the RDSGEIS portray access road stream crossings, but the impacts of the stream crossing are not addressed.

Road crossings of streams and wetlands will be unavoidable during the development of HVHF sites. Section 5.1.1 acknowledges that the length of road may be influenced by selecting a route to avoid environmentally sensitive areas, but mitigation measures recommending such route selection are not specifically addressed in either Chapter 7 or the Draft HVHF SPDES Permit. Estimates of the number and extent of anticipated stream and wetland crossings are not provided in Section 5.1.1.

Recommendation: The proximity of roads to streams and wetlands, and the unavoidable need to cross streams and wetlands, increases the risk that erosion and sedimentation will cause measurable impacts on water quality. Poorly constructed stream crossings can directly impact aquatic communities.[3, 7] Excessive sediment

levels are one of the primary threats to US surface waters[10] and have multiple effects on stream health. The RDSGEIS should provide estimates of the anticipated extent of road crossings of streams and wetlands, as well as an evaluation of the potential environmental impacts of these crossings. Furthermore, avoidance and mitigation measures should be addressed in the RDSGEIS and incorporated into the regulatory process. Specific requirements and guidelines to mitigate the impacts of stream and wetland crossings should be provided.

Recommendation: If the SPDES HVHF GP is to be the primary mechanism for regulation, then the permit should include a defined documentation process to require the applicant to reduce the number and extent of stream crossings. This section should be incorporated into Part IV, *Contents of the Construction SWPPP*, as a requirement of Section A.1 and include both mapping requirements and narrative that documents the need for each stream crossing and explanation as to why any individual stream crossings cannot be reduced or combined. Road crossings on areas specifically in conflict with local government land use regulations should be identified, as well as road crossings on steep slopes erodible soils, or intact woodlands.

Comment 4:

Section 5.1.2 *Well Pads* notes that well pad size is determined by site topography, but no estimates are provided regarding the impact of slope on well pad size and disturbance footprint, and the increased impacts on erosion and sediment discharge. The area of disturbance can be increased by up to 50% on slopes exceeding 15 degrees[8] (the Draft HVHF SPDES permit allows disturbance on slopes up to 25% in AA or AA-s watersheds. It is not clear that there is a limit on slope construction in other watersheds). The stormwater and erosive impacts of well pads on steep slopes continues through the life of the well pad. At a minimum, the Draft SPDES HVHF GP should preclude well pad construction on slopes over 25%.

Recommendation: Section 5.1.2 should provide some evaluation of the anticipated increase in well pad disturbance as a function of slope (and required cut and fill) as a result of the impacted terrain conditions specific to New York. Section 7 of the RDSGEIS should provide discussion of specific mitigation measures to reduce the impacts of well pad construction on slopes. The HVHF SPDES permit should include specific requirements to reduce construction of well pads on steep slopes, limits on steep slope construction in all watersheds, and provide discussion and requirement of implementation measures to reduce the long-term water quality impact of well pads on slopes when such systems are constructed. Additional measures to prevent sediment discharge from construction on steep slopes should be defined and required as part of the facility SWPPP. It is not clear that the general requirements of either the 2005 New York State Standards and Specifications for Erosion Control or the 2010 New York State Stormwater Management Design Manual provide sufficient specific guidance to address the additional impacts associated with well pad construction on slopes. Both erosion control measures and stormwater measures must be adjusted in their design to account for the greater water quality impacts of well pad location on slopes.

Comment 5:

Section 5.1.2 *Well Pads* and **Section 5.1.4** *Well Pad Density* do not provide any specific information or estimates of well pad or HVHF facility location or density with regards to watershed drainage areas, or analysis of the anticipated density of well pads within intermittent or perennial headwater stream drainage areas. Section 6 does not discuss the impacts on water quality of well pad density within the drainage area of an intermittent or perennial stream. Headwater and intermittent perennial streams originate with a drainage area of 5.5- to 37-acres[5], increasing the likelihood of a HVHF well pad being within several hundred feet of an intermittent or perennial stream, and the likelihood that the disturbance will represent a sizable portion of the total drainage area to a headwater stream (i.e. 7.4 acres of total disturbance for a multi-well pad during the drilling phase, and 1.5

acres of disturbance during the drilling phase could represent a very large percentage of the drainage area of a headwater or small stream).

Recommendation: Current research[2] indicates a positive relationship between stream water turbidity and well density within a drainage area or watershed. The RDSGEIS does not provide any analysis or consideration of potential levels of watershed disturbance as a result of HVHF activities, and the resulting potential impacts on water quality, although such an analysis is well within current mapping and GIS capabilities and should be included in the RDSGEIS.

Comment 6:

While some mention of gathering lines is included in **Section 5.1.3** *Utility Corridors*, including an estimate of 1.66 acres per well pad, no discussion is made of the anticipated extent of stream crossings, or the cumulative levels of land disturbance associated with gathering lines on a watershed or other basis. No further discussion is provided in Chapters 6 and 7 specific to gathering lines. It is unclear exactly how the current DEC permit process for pipeline stream crossing is adequate to protect water quality from either a land disturbance or stream crossing impact from gathering lines, or how gathering line construction will be addressed and/or coordinated with the Draft HVHF SPDES permit process (which does not currently address gathering lines).

Recommendation: This issue requires additional consideration in the RDSGEIS, and the specific permitting requirements for gathering line stream crossings should either be identified in the Draft HVHF SPDES permit or coordinated with this permit so that impacts are reduced. Specifically, measures to reduce the impact of gathering line stream crossings (and general construction) by coordination of this construction with other well site needs should be required.

Comment 7:

Chapter 6, Potential Environmental Impacts. Section 6.1.2 *Stormwater Runoff*, discusses both stormwater impacts and erosion and sedimentation construction issues. However, this discussion is very general in nature, comprising only 1-1/4 pages within Chapter 6 for both of these topics. No discussion is provided regarding the specific magnitude and issues of concern associated with stormwater and erosion impacts from the various HVHF activities (i.e. well pad construction, and variations on well pad construction such as disturbance footprint from construction on steep slopes). Rather, it is simply noted that the potential for water resource impacts exists, and that these impacts may cause increased runoff volumes, greater erosive forces, heightened sediment loads, etc.

Recommendation: Research data and engineering methodologies are available to quantify the potential adverse water quality impacts, either on a "typical" facility basis or an anticipated watershed basis (using the estimates of acreage developed in Section 5). Such analysis would provide at least some basis for determining whether the requirements of the Draft HVHF SPDES GP are adequate for the industry. These estimates would also provide information on the cumulative impacts of HVHF on water quality and stream health and should be included in the RDSGEIS.

Comment 8:

Chapter 7, Mitigation Measures. Section 7.1.2 *Stormwater,* discusses stormwater management in general terms, with a non-specific discussion of the particular issues associated with HVHF stormwater and erosion. Much of the generic discussion focuses on pollution prevention from exposed industrial activities. Less than one page addresses stormwater management mitigation measures related to land use changes, and one-half page addresses mitigation associated with stormwater and erosion issues from construction activities. Section 7.1.3 discusses spills and

containment, which is also addressed in the SPDES HVHF GP. However, much of this discussion is focused on industrial spill control, not stormwater impacts.

Chapter 7 indicates that the Department intends to issue a single SPDES General Permit that will encompass all issues of construction stormwater and erosion control, post-construction stormwater management, industrial stormwater management, and pollution prevention/spill control. Specifically, page 7-26 states: *The Department has determined that natural gas well development using high-volume hydraulic fracturing would require a SPDES permit to address stormwater runoff, erosion, and sedimentation. The SPDES permit will address the construction of well pads and access roads and any associated soil disturbance, as well as provisions to address surface activities associated with high-volume hydraulic fracturing for natural gas development. Additionally, during production of the natural gas, the Department will require coverage under the SPDES permit to remain in effect and/or compliance with regulations. The Department proposes to require SPDES permit conditions, a Comprehensive SWPPP (stormwater pollution prevention plan), and both structural and non-structural Best Management Practices (BMPs) to minimize or eliminate pollutants in stormwater. The Department is proposing the use of a SPDES general permit for high-volume hydraulic fracturing (HVHF GP), but the Department proposes to use the same requirements in other SPDES permits should the HVHF GP not be issued.*

Recommendation: The HVHF SPDES permit should be specific to this industry and impose requirements that reflect the lack of local government review and approval of the land development activities associated with the industry. The RDSGEIS should specifically identify the areas where additional permit requirements specific to the industry are necessary to protect water resources.

Comment 9:

Section 5.1.1 *Access Roads* notes that roads may be constructed by placing crushed stone or gravel, but Section 6 does not specifically address the water quality issues

associated with the long-term use of gravel roads (after construction), nor does Section 6 provide any estimate of potential pollutant loadings associated with gravel roads, specifically estimates of sediment generation. Research data[4] indicates that gravel roads can be a significant source of sediment pollution, and data to support sediment pollutant load estimates is available but requires an estimate of the anticipated extent and area of gravel access roads to be constructed, which is not provided in Section 5.1.1. Gravel access roads serving HVHF will be subject to undefined levels of truck traffic, which has a greater impact on road condition and erosion than regular vehicle traffic. Section 6.1.2 *Stormwater Runoff* discusses the impacts of sediment on streams and notes that "*steep access roads…pose particular challenges.*" **Section 7.1.2** *Stormwater* indicates that the construction of access roads will be addressed by the SPDES permit, but neither Section 7.1.2 nor the Draft HVHF SPDES permit provide specific recommendations to reduce the length and width of gravel access roads, to reduce construction access roads on steep slopes, or to reduce the specific impacts of gravel road and sediment generation once the construction period has ended. General reference to the State stormwater manual is not sufficient for this issue as it relates to HVHF. There is no requirement in the Draft HVHF SPDES mapping requirements to indicate or accurately depict the length, width, or slope of gravel access roads. Since these areas will generate sediment pollutants through the life of the project, specific guidelines to mitigate pollution from access roads are warranted.

Recommendation: The RDSGIES should provide more detailed information on the specific impacts of gravel access roads with regards to sediment generation, and the estimated extent of potential pollutant loads. Section 7 of the RDSGEIS should provide discussion of specific mitigation measures to reduce the impacts of access road construction. The HVHF SPDES permit should indicate specific requirements for the documentation of access road lengths and widths, and requirements to reduce construction on steep slopes, reduce road width, and implement other measures to reduce the water quality impact of access roads. Measures to maintain

gravel access roads in a manner that prevents sediment discharge (over the life of the project) should be defined and required as part of the facility SWPPP.

Comment 10:

Section 7.1.11.1 *Setback from private well*, Section 7.1.11.1 states that "The Department proposes that it will not issue permits for high-volume hydraulic fracturing within 500 feet of a private water well or domestic supply spring unless waived by the landowner." However, the Draft SPDES permit does not require the applicant to map the location of private water wells or springs that may be within 500 feet, or to notify the landowner. Coverage under the GP is granted within 30 calendar days of the Department receiving the NOI (and meeting the requirements of Part II.B.2). How will the Department or the applicant be aware of the existence of private water wells within 500 feet? This is also not included in Section 5 of the Environmental Assessment Form, but IS included in the Proposed EAF Addendum Requirements for HVHF. It is not clear how 500 feet was determined as sufficient distance to support a private well from HVHF activities as no supportive reasoning is provided.

Recommendation: Require that all private water wells and domestic supply springs within 2,640 feet and 500 feet, respectively, to be located on the Site Map (prepared under Part IV.C.1.b and as a requirement to the Site Map in the SWPPP). The NOI form should require that the applicant confirm that there are no such wells within 500 feet, and provide proof to the Department of landowner waiver receipt (by certified mail or similar means).

Recommendation: The SWPPP should identify the private water well or spring in the narrative (Part XI.3) and identify measures undertaken to protect the private well and to address emergency spill situations.

Comment 11:

Section 7.1.11.2 *Setbacks from Other Surface Water Resources* states "Existing regulations prohibit the surface location of an oil or gas well within 50 feet of any 'public stream, river or other body of water.'" The 1992 GEIS proposed that this distance be increased to 150 feet and apply to the entire well site instead of just the well itself". The Draft HVHF SPDES permit (Section I.D.4) requires a setback of 150 feet from the well pad and perennial or intermittent streams, but does not address setbacks from other HVHF site components.

Recommendation: As discussed later in specific recommendations associated with the Draft HVHF SPDES permit, required setbacks of any length are meaningless unless the water features are accurately identified and located. A USGS 7-1/2 minute topographic map, at a scale of 1" = 2000' is inadequate for this purpose. It is essential that the Draft HVHF SPDES permit require mapping at a scale that can accurately depict both existing natural features (such as steep slopes and headwater streams) as well as proposed HVHF components.

Comment 12:

There are benefits associated with a single SPDES GP (or a single individual SPDES permit) that addresses construction, post-construction stormwater, and industrial stormwater and spill containment for each project in one permit. These benefits include a comprehensive evaluation of each project, potential continuity in responsible facility personnel, and consistency of management practices through both construction and operation.

However, the Department is largely drawing on the current requirements in the existing SPDES general permit for construction (New York State Department of Environmental Conservation SPDES General Permit For Stormwater Discharges From Construction Activity Permit No. GP-0-10-001) and the existing SPDES general permit for industry (New York State Department of Environmental Conservation SPDES Multi-Sector General Permit For Stormwater Discharges Associated With

Industrial Activity Permit No. GP-0-06-002). The Department is combining many (but not all) requirements of these two GPs into one HVHF GP and, in doing so, does not include provisions that would otherwise be required of permittees seeking either of the existing permits alone..

For the issues of site disturbance, stormwater management, setbacks, disturbance of sensitive features, erosion, and other impacts associated with many non-HVHF land development projects and industrial activities, there is an additional level of professional review and regulation in the form of local laws, regulations, plans or policies implemented by the local planning board or authorized board. In other words, for non-HVHF projects, such as land development projects, there is often a local project review of proposed plans by a professional reviewer knowledgeable in local conditions, supported by the review of an authorized board whose members possess local knowledge. Local regulations are likely to impose more rigorous mapping requirements, stormwater calculations, and design detail than those imposed in a Department general permit, and furthermore, project submissions receive local, professional review. In these circumstances, successful design and compliance (with the requirements of Department general permit) is more likely when supported by a secondary level of performance requirements and review at the local level.

The issuance of a single GP for HVHF (that encompasses many requirements of both existing Department GPs) will not have the benefit of local review and specific local performance requirements. The potential impacts of HVHF projects on land disturbance, stormwater, erosion, sensitive sites, etc. is at least as significant (if not more significant) than other, locally regulated land disturbance and industrial activities. HVHF is also a "heavy" industry that will be located in many areas unaccustomed to heavy industry.

Recommendation: The Department should provide the opportunity for local review by revising the SPDES HVHF GP to address compliance with applicable local ordinances. For instance, those activities which would typically require issuance of

GP-0-10-001 should be required to comply with all local ordinance requirements as they apply to HVHF activities. Additionally, the Department should require SPDES HVHF GP permittees to provide written notification to the Department from the affected local governments that the conditions of local ordinances are met to the satisfaction of the local governing authority prior to issuance of the permit. Comment 14 below discusses this further.

Comment 13:

HVHF compliance with the requirements of the GP are largely self-reviewing and self-monitoring, as facilities are required to develop and implement a SWPPP, but there is generally no review of the SWPPP unless the Department elects to request and review the SWPPP for a specific facility. Absent this specific request by DEC, the SWPPP is simply maintained on-site. In addition, DEC does not propose any mechanism that would enable it to effectively evaluate successful implantation of a SWPPP.

Recommendation: The SPDES HVHF GP should be revised to make public all documents, specifically including the SWPPP, available for review by the Department and the public. In all instances, the Department should establish a mechanism to routinely review whether applicants have successfully implemented their SWPPPs. Dated digital photos that support inspection and compliance per permit and SWPP requirements should be a requirement for permit coverage.

Comment 14:

Chapter 8 , Permit Process and Regulatory Coordination; **Section 8.1.1.5** *Local Planning Documents* of the SGEIS states:

> *However, in order to consider potential significant adverse impacts on land use and zoning as required by SEQRA, the EAF Addendum would require the applicant to identify whether the proposed location of the well pad, or any*

other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies. The applicant would also be required to identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s). For actions where the applicant indicates to the Department that the location of the well pad, or any other activity under the jurisdiction of the Department, is either consistent with local land use laws, regulations, plans or policies, or is not covered by such local land use laws, regulations, plans or policies, the Department would proceed to permit issuance unless it receives notice of an asserted conflict by the potentially impacted local government.

This approach is problematic. While it is the responsibility of the applicant to determine whether or not there are any conflicts, it is up to the potentially impacted local government to provide notice to the Department of an asserted conflict that has not been identified by the applicant. Although the RDSGEIS states that the Department would notify local governments of all applications for high-volume hydraulic fracturing in the locality, through the use of an electronic notification system to local government officials (see DSGEIS at 8-4), DEC offers no guarantee that this system will be in place prior to the issuance of permits and does not specifically describe when in the permitting process such notification to local governments will occur. These are critical issues that should be addressed. Further, it is unclear how the Department will determine *"whether significant adverse environmental impacts would result from the proposed project that have not been addressed in the SGEIS and whether additional mitigation or other action should be taken in light of such significant adverse impacts." RDSGEIS at 8-5.* It is also not clear as to whether this determination process applies to all HVHF GP applicants, or only those subject to SEQRA determination.

Recommendation: In consideration of the Department's decision to regulate HVHF under a single SPDES general permit without the important supplemental benefit of local review and local laws, regulations, plans or policies (that virtually all other

land development and industrial construction projects are subject to when obtaining SPDES permit coverage), obtaining General or Individual Permit coverage (for all HVHF projects) should also require the applicant to notify the local government (as well as the Department) that there are no conflicts with local laws, regulations, plans or policies, and to provide supporting documentation of the evaluation to the local government and Department. This will allow local governments to receive the necessary information to "assert" a potential conflict that may not have been identified by the applicant. Without this critical information, local governments cannot be expected to "assert" a potential conflict to the Department.

Comment 15:

As discussed above, Section 5.1 of the RDSGEIS provides estimates of land disturbance for well pads and associated construction activities (roads, utility corridors, compressors, etc.), including total estimated disturbance per pad for multi- and single-well pads. The RDSGEIS notes that most wells will be multi-pad wells with a net disturbance of 7.4 acres per pad (reducing to 1.5 acres per pad during production). A spacing of 640 acres per multi-well pad is presented in Table 5.1 of the RDSGEIS. However, no consideration is provided of the anticipated disturbance and well pad density on a watershed basis, or proximity to streams and anticipated stream crossings, and no consideration is provided on the potential individual and cumulative effects on stream health.

A recently published study of natural gas development in the Fayetteville and Marcellus formations in Arkansas and Pennsylvania[2] used current topographic data, well development data, and readily available land use analysis computer modeling tools (ArcHydro Version 1.3) to evaluate both the overall well pad density per drainage area and well proximity to streams in these formations in Arkansas and Pennsylvania. This desktop analysis was further supported by in-stream turbidity measurements in seven different drainage areas with different well densities.

This report had several significant findings, most notably it "identified a positive relationship between stream water turbidity and well density. Turbidity was not positively correlated to other land use cover variables." (Entrekin, et al, "Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters, pg 507). The report further concluded that "preliminary data suggest that the cumulative effects from gas well and associated infrastructure development are detectable at the landscape scale."

This study also determined that approximately 17% of the active Pennsylvania wells were within 100 meters (328 feet) of a stream, and all wells were within 300 meters (984 feet) of a stream. Gas wells "were located, on average, 15 km (9.3 miles) from public surface-water drinking supplies and 37 km (23 miles) from public well water supplies." The report noted that "although wells are generally constructed far from public drinking-water sources, there is potential for wastewater to travel long distances given that many of the components, such as brines, will not settle out or be assimilated into biomass." In other words, due to the nature of material from HVHF wells, discharges that reach streams (due to inadequate stream setbacks) may travel to public drinking supplies, even if the surface water supplies are distant to the well.

Chapter 6 of the RDSGEIS broadly identifies potential environmental impacts on water resources (Section 6.1), including polluted stormwater runoff and spills. The RDSGEIS does not specifically discuss the cumulative impacts of land disturbance on surface water quality (i.e. whether turbidity or other measures of stream impact increase with well density). The RDSGEIS makes no attempt to estimate well density and land disturbance on a drainage area basis with regards to water quality impacts or consideration of specific watersheds and designated uses. No specific consideration is given to the topography and stream density of New York State with regards to land disturbance and proximity to surface waters.

Such an analysis would provide a far better estimate of potential surface water impacts and the extent of anticipated land disturbance on a watershed or drainage area basis. This information would inform the state as to the watershed impacts

from HVHF activities, and provide some additional basis for well density in different watersheds. It would also better inform the decisions regarding setback distances discussed in Sections 7.1.5 and 7.1.11.2.

As discussed previously, most headwater and small perennial streams are not indicated on USGS 7-1/2 minute topographic quadrangles, and hence will not necessarily be identified under the current mapping requirements in the Draft HVHF SPDES permit. Headwater streams generally originate with a surface drainage area of 5 to 37 acres.[5] The study discussed above had a stream threshold of 12.4 acres. With a disturbance footprint of 7.4 acres per multi-well pad, drilling activities could potentially impact as much as 60% of the land area in a headwater stream drainage area (assuming 12.4 acres per drainage area). The extent and impact of land disturbance in headwater streams is not addressed in any manner in the RDSGEIS.

Recommendation: The RDSGEIS should provide some technically supported evaluation of the anticipated well density on a drainage area basis, with consideration of water quality impacts. The analytical land use tools, data, and models available today are significantly more robust than the environmental tools available during the development of the 1992 GEIS (and such tools are often used to support TMDL determinations). In other words, the density of anticipated land disturbance and proximity to streams and wetlands could easily be mapped and evaluated using anticipated development rates and relevant information from states such as Pennsylvania. At a minimum, representative watersheds could be evaluated in detail to represent anticipated conditions, and using topographic data and average proximity to streams could be estimated. Relevant well drilling data is also available from other states such as Pennsylvania. High-volume hydraulic fracturing is "distinct from other types of well completion" as noted in the RDSGEIS, and warrants additional consideration.

This type of land use and density evaluation will allow the Department to better assess the potential impacts of high-volume hydraulic fracturing on both watershed

land use and proximity to streams, and can provide a technical basis for HVHF well density and setback decisions. It can also inform decisions regarding well density and setbacks in waters with TMDLs. But at this time there is no watershed impact consideration of HVHF well location and density. It is unclear whether the various setbacks discussed in the RDSGEIS are adequate to protect water resources during HVHF activity, or whether these setbacks merely represent an arbitrarily selected value.

Recommendation: To facilitate Department identification of wells that may have an impact on small headwater streams, the Draft SPDES HVHF GP could require that each well pad application document the total amount of anticipated land disturbance, and the percent of land disturbance within the drainage area of the well pad location. This is not a difficult estimate for the permit applicant to develop using current mapping tools, and will provide some indication that adjacent streams may be small and especially vulnerable to land use impacts.

Comment 16:

Section 7.1.3.1 indicates that fueling tanks are considered "non-stationary" at well pads, and therefore exempt from Department storage and registration requirements. Section 7.1.3.1 does state that secondary containment is required for all fueling tanks, and that fueling tanks would not be positioned within 500 feet of perennial or intermittent stream, storm drain, wetland, lake or pond.

It is unclear how this requirement will be met or maintained, especially in light of the fueling tanks being "non-stationary." Specific requirements are not reflected in the Draft HVHF SPDES permit, either in the general SWPPP requirements or the Fueling Area requirements. It is unclear how this setback will be identified and maintained, and how the Department intends to ensure compliance. The requirements for fueling areas in the Draft HVHF SPDES permit are the same general requirements applied to all industrial facilities and do not have any specific consideration of the nature and conditions of HVHF sites and fueling needs.

Recommendation: The RDSGEIS and Draft HVHF SPDES permit must address the issue of containment for "non-stationary" fueling tanks, and all other non-stationary tanks.

Comment 17:

The RDSGEIS **Section 7.1.7.2 Road Spreading** indicates that NORM concentration data in brines is insufficient to allow road spreading under a BUD, and that as more data becomes available the Department will evaluate the BUD petitions. However, the RDSGEIS is inadequate in that no consideration has been made of the total potential increase in chlorides on roads as a result of the HVHF industry disposing of brines in this manner, and the anticipated levels of chlorides and other compounds in the brine. Again, the RDSGEIS has not considered the cumulative impacts of the generation of this material and the potential volume of material application on roadways. No estimate is made of the volume of production brine that may be disposed of on roadways. No consideration is provided regarding what might be "safe" levels of chlorides (or other compounds) in different situations, or what other additional compounds that may be found in production brine that would preclude the use of the material for roadway application. The requirements in the current BUD have no basis as being sufficient for protecting water quality, and are generally self-monitored by the industry.

Unless the use of production brine is demonstrated as being a beneficial use for the public in roadway safety, application to roadways should not be seen as a viable disposal method. Much more research on the effects of the material on plant and aquatic systems is required.

Recommendation: The RDSGEIS should provide better information regarding anticipated brine production levels and disposal needs as a result of HVHF activity. Future authorization of the application of brines under a BUD should not be allowed until this information has been developed and provided for public review and comment.

Comment 18:

Section 7.1.9 Solids Disposal indicates that the generation of acid rock drainage (ARD) may occur as the result of material from certain portions of the Marcellus shale. The RDSGEIS indicates that an ARD mitigation plan would be required for in-site burial, but is not required for off-site disposal.

No estimate is provided within the RDSGEIS of the potential amount or magnitude of the generation of this material, and whether or not the amount of ARD material is of concern, or within which watersheds such material may be anticipated. The generation of ARD is of significant concern and impact on watershed health, and warrants more detailed analysis of the anticipated locations and extent where ARD may be an issue. It is not clear if this is expected to be an extensive concern, and no consideration is made of the amount and extent of the ARD material encountered in other states such as Pennsylvania, and how much this material has created additional acid discharge problems in other states. This issue is not addressed in the HVHF SPDES draft permit.

Recommendation: Estimates of the anticipated extent of such material should be included in Chapter 6.1.9.2, and coordinated requirements for ARD treatment (as discussed in Section 7) incorporated into the Draft HVHF SPDES permit. This material has significant potential impact to water quality.

Comment 19:

The EAF addendum should clearly define the process and timeline for notification of local government, and for the Department's process for determination of permit applicability when notice is received from the applicant or local governments that a conflict with local laws, regulations, plans or policies exists. Furthermore, the EAF addendum should address the issue of HVHF GP coverage upon NOI submission when such local conflicts exist.

Recommendation: Coverage should NOT begin until proof of notification to local governments has been received by the Department, local governments have been provided sufficient information and time to "assert" any unidentified potential conflicts, and the Department has made project specific determinations regarding the impact of identified or asserted conflicts. A timeline and process must be defined.

Comment 20:

EAF Appendix 12 Beneficial Use Determination (BUD) Notification Regarding Road Spreading states that "Any person, including any government entity, applying for a Part 364 permit or permit modification to use production brine from oil or gas wells or brine from LPG well storage operations for road spreading purposes (i.e. road deicing, dust suppression, or road stabilization) must submit a petition for a beneficial use determination (BUD)." This petition must include sampling data (although the sampling parameters are limited), a map indicating roads where brine is to be spread, and a general narrative of practices to be implemented, including avoiding applying brines within 50 feet of a stream or waterbody, avoiding application during rainfall periods or on slopes greater than 10 percent.

Chlorides are toxic to many plants and freshwater aquatic plants and invertebrates[14] with levels as low as 30 mg/L toxic to plants, and at 1000 mg/L toxic to aquatic plants and invertebrates. Chlorides also impact the use of surface water for potable water sources.

While chlorides are applied to roads during snow and ice conditions for safety reasons, many state Departments of Transportation have begun programs to significantly reduce the use of chlorides and implement alternative de-icing practices to reduce the impacts of chloride on both vegetation and stream system health.

Recommendation: Additional analysis of potential impacts must be done to evaluate potential impacts from road spreading, including analysis to support that the proposed setback criteria are sufficient to protect water quality, as well as to define required sampling requirements for BUD petitions.

Comment 21:

In addition to defining the processes and timelines for review and notification requirements, coordinating permit approvals and public participation activities would ensure compliance with all applicable statutes and eliminate any conflicts that may arise. Regulatory permit tracking, municipal coordination and public outreach and participation should be integrated and automated to the fullest extent possible to ensure satisfactory oversight of gas development operations. This includes the use of internet and GIS technologies for geovisualization, database management, and compliance with all regulatory requirements.

One example of internet-based GIS information sharing is the Pennsylvania Department of Environmental Protection's (PA DEP) eMapPA website. PA DEP uses this online application that is updated on a regular schedule and tied to a multitude of databases which track publicly available information (air quality, water quality, mining/reclamation, natural resources, etc.) on a publicly accessible GIS website. (See http://www.emappa.dep.state.pa.us/emappa/viewer.htm).

Recommendation: With regard to regulatory permit tracking, PA DEP has developed an additional tool called Environment, Facility, Application, Compliance Tracking System (eFACTS). PA DEP staff, as necessary, has internal agency access to this database system, cross-referenced by regulatory program, in which permits and permittees may be tracked and updated with regard to permits issued, violations, etc. This information is also available to the public, in a limited format, via the internet at http://www.dep.state.pa.us/dep/efacts/efacts.html. If not already available through the NYS Department Application Review Tracking (DART) system, the development of such a system would be very beneficial for tracking SPDES

HVHF GPs, as well as other state issued permits associated with gas development projects, including dirt/gravel roads, stream crossings, etc. This information should be linked to any web-based GIS application.

Recommendation: Population of a geodatabase may occur through the submission of GIS data by permittees. Permit application packages could and should be front loaded for digital information by requiring permittees to submit GIS data (i.e., shapefiles in an accepted Metadata format) about their project sites. At a minimum, a project boundary on georeferenced state plane coordinate system should be required. This website should also link each project boundary to any online permit tracking system, including the email address of appropriate personnel to whom comments may be submitted.

Recommendation: In addition to sharing GIS data with local governments, NYSDEC should, if it has not already, implement a requirement for municipal notification similar to those commonly referred to in Pennsylvania as Act 14 notices. Pennsylvania permitting processes include requirements for written notifications to be sent to each municipality and county government in which the permitted facility is or will be located under an amendment to the Commonwealth's Administrative Code. These notifications allow 30 days for specific municipal and county comments.

Recommendation: Additional public participation may be solicited by the publication of notices of pending permits in NYSDEC's Environmental Notice Bulletin (ENB). Certain SPDES permitting actions are already included in the monthly ENB; however, it may be beneficial to provide a section specific to those SPDES permits issued for HVHF gas development on the ENB website and linked to the DART system.

Comments on the Draft SPDES HVHF GP

Impacts to surface water quality from gas exploration and extraction activities can occur during the construction of the facility, the operation of the facility, and as a result of inadequate restoration of the facility after operations have ceased. Applying specific performance standards and consistent regulatory oversight through a thorough permitting process is essential to ensuring the prevention of water quality impacts. A comprehensive permitting process should include, but not be limited to, the following considerations:

- Clearly defined permitting process and timelines;
- Sound technical guidelines specific to the activities being permitted;
- Compliance with both State and local regulations prior to final permit approvals;
- Opportunities for public participation, outreach, and comment.

These considerations, as well as a comprehensive evaluation of all potential environmental impacts, are essential to the development of permitting procedures that are adequately protective of environmental resources.

The RDSGEIS notes that certain water resources, such as the New York City and Syracuse drinking water supplies, have been the subject of extensive comment and warrant different regulatory requirements (i.e. a prohibition on drilling). Specifically, the "Department finds that standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing." RDSGEIS at 7-55.

In a paper prepared by Patrick O'Dell, a professional engineer with the National Park Service Geologic Resources Division, Mr. O'Dell noted that "If the public

depends on operators in general to voluntarily use measures such as 'best management practices' to meet an agency's standards of resource protection, the public will be disappointed. This is because operators are sometimes willing to assume more environmental risk in exchange for a reduction in expense or acceleration of project completion."[8]

Given these comments, and that the Department recognizes that "*standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing*," and the Department's decision to preclude HVHF in FAD watersheds (Section 7.1.5), the validity and effectiveness of a self-monitoring GP process for other watersheds cannot be assumed to be protective of water resources, and the SPDES permit and associated regulatory activities must be developed to address these concerns.

In comments provided to the Pennsylvania DEP, Dr. James Schmid[14] PhD made the following recommendations that are directly applicable to NYSDEC regarding the HVHF SPDES permitting process in New York:

a. Place all gas-related permit applications, issued permits, and enforcement actions online in an electronic database accessible by public.
b. Include stream encroachment for pipelines *(in the SPDES permit).*
c. Select a significant number of permit applications for file and on-site audit, to ascertain trends in adequacy of permitting process.
d. Disallow general permits in Exceptional Value and High Quality waters (or in New York, require individual permits for AA or A drinking water streams and T or TS trout streams).
e. Require an inventory for all EV or HQ streams within 500 ft of well pads.

f. Make an attained use determination at every stream proposed for impact that has not been studied.
g. Require disclosure of ALL related facilities in each project application, require disclosure of all land and water disturbances for each well or well pad so that projects do not incorrectly fall below thresholds.
h. Require construction of impermeable holding areas sufficient to contain spills and prevent release outside pad.
i. Require accounting of tree clearing. Provide plans and timetable for reforestation.
j. Gathering lines and water pipelines should follow existing roads rather than new ROWs. New ROWs should be demonstrated to reduce stream/wetland crossings.
k. Distinguish between new stream crossings and those made atop existing culverts.

With these and other previously discussed recommendations in consideration, the following comments are provided with regards to the current Draft HVHF SPDES General Permit:

Comment 1: The Draft HVHF SPDES permit is primarily a compilation of the existing Construction SPDES GP (001) and the Industrial Stormwater GP (002). It has not been significantly modified to address the issues specific to HVHF. Additionally, the Draft HVHF SPDES permit should encompass ALL components of a well project (well pads, access roads, water lines, gathering lines, compressor stations, water withdrawals, transportation of materials, waste management) with considerations specific to HVHF, or clearly provided coordination with other permitting requirements specific to these issues.

Comment2: Given the lack of local land use review, the mapping and data requirements for the SWPPP should be coordinated with the mapping/data

requirements of the Environmental Assessment Form, and all information should be available digitally for access by local government, property owners, and the general public. The RDSGEIS Appendix 5 *Environmental Assessment Form Attachment to Drilling Permit Application* does NOT reflect all site data requirements described in Appendix 6 *Proposed EAF Addendum Requirements for High-Volume Hydraulic Fracturing*.

Comment3: The SPDES HVHF GP should be modified to include construction and stormwater discharges related to gathering lines, compressor stations and compressor station access roads, or to clarify how these activities will be addressed under another permit.

Comment 4: In the absence of more explicit requirements, such as the submission of supporting calculations for BMP design, owners/operators are likely to use a generic narrative for multiple wells, with exception of mapping requirements. It is important that the SPDES HVHF GP requirements for mapping be site specific, comprehensive, at a scale that provides info needed. Generic SWPPPs tend to be ignored.

The following comments are in regard to specific sections of the Draft SPDES HVHF GP as noted.

Part I GENERAL PERMIT COVERAGE AND LIMITATIONS

Comment 5:

Section B.2 Maintaining Water Quality – This section places the burden of identifying a violation of a water quality standard on the Department, as opposed to the permittee. In the Industrial Stormwater GP, the burden of identifying such stormwater discharges is placed on the permittee: "*If there is evidence indicating*

that the stormwater discharges authorized by this permit are causing, have the reasonable potential to cause, or are contributing to an excursion above an applicable water quality standard, the permittee must take appropriate corrective action and notify DEC of corrective actions taken." Similar responsibility should be placed on the permittee for HVHF activities.

Comment 6:

Section C.3 Non-Stormwater Discharges – This section authorizes non-stormwater discharges and adds "uncontaminated discharges from well site dewatering operations" to the list of allowable non-storm discharges. Is this section referring to only de-watering of erosion and sediment control measures in site development or to well drilling material? This should be clarified.

Comment 7:

Section D.2 Activities Which are Ineligible for Coverage under this General Permit – This section precludes the construction of HVHF only on locations where the stream designation is AA or AA-s, **and** there is no impervious cover **and** the slopes are greater than 25% or E / F slope designation. Does this mean that if there is some impervious cover on such a site that HVHF is allowed? Does this mean that all other sites have no limits on slope (unless identified by the applicant as addressed in local land use regulations **and** identified as an objection by local government)? Is disturbance of steep slopes allowed in T streams? Should steep slope disturbance be precluded in proximity to water bodies and wells and identified in setbacks? The RDSGEIS notes in Section 6.1.2 that "*Steep access roads, well pads on hill slopes, and well pads constructed by cut-and-fill operations pose particular challenges, especially if an on-site drilling pad is proposed.*" This section should be substantially re-evaluated to preclude or define limits on coverage for steep slopes, etc. in all watersheds. Additionally, the Department should develop specific performance parameters/requirements for coverage of such activities on steep slopes under an Individual Permit for sites not addressed under the GP, rather

than issuing an Individual Permit that is substantially similar to the GP. Additionally, this section should clarify that local land use regulations regarding steep slopes and other environmental constraints apply unless waived by local government.

Comment 8:

Section D.4 Setbacks for Well Pad – These setbacks should reflect further consideration in the RDSGEIS, and include all setbacks discussed and identified in the RDSGEIS and appendices – such as setbacks from private water supply wells and springs, public water supply wells, residences, etc. This section should also clarify where ALL HVHF activities are prohibited (i.e. within 100-year floodplain, within 4,000 feet of unfiltered water supply watersheds, within 2,000 feet of public water supply, etc.).

All setback dimensions should be indicated on the GP mapping requirements.

Additionally, this section should clarify that local land use regulation setbacks also apply unless waived by local government. The permittee should prepare documentation that such land use regulations have been evaluated, and the local government notified if local land use requirements have not been met.

Part II Obtaining General Permit Coverage

Comment 9:

A. Notice of Intent (NOI) Submittal – The applicant is required to submit an NOI form to the Department, and prepare a SWPPP. The SWPPP must be available to the Department (if requested) and maintained on site. This process does not provide for public access and notification (other than the publication in a newspaper, which is easily overlooked by the public).

The public, including immediately adjacent property owners, should have opportunity for notification when such notification is submitted to the Department.

Many local governments have adjacent property owner notification requirements as part of the local zoning and land development process. Since this process does not apply to HVHF, a process of notification to adjacent and potentially impacted property owners should be included in Section II.A. Clarification of the definition of "potentially impacted property owners" requires further consideration in the RDSGEIS. Potentially, notice should be provided to water suppliers, etc.

If coverage under the GP is dependent upon development and implementation of the SWPPP, then the SWPPP must be available for public review upon request. It is likely that most members of the general public would not necessarily know how to request or obtain a copy of the SWPPP. As previously suggested, an on-line database would allow public and Department access to the SWPPP. It is unreasonable to allow the industry to obtain GP coverage without an opportunity for public comment.

Comment 10:

B.2.3.b General Permit Authorization – Given the unique nature of HVHF construction, and the lack of local government review regarding land use disturbance and stormwater management, the permit should impose a time period between preparation and submission of any and all required materials and actual permit coverage. All material should be digitally submitted and all information regarding land disturbance activities should be available and accessible for public review and comment, with a minimum 30-day period for public comment before permit coverage. HVHF practices are different from other industrial practices and coverage under a general permit must provide some process for public review and comment on permit coverage.

Comment 11:

C. Impaired Waters and TMDLs – The RDSGEIS has not provided any documentation or consideration as to whether a general permit is sufficient to prevent further water quality impacts in impaired waters and especially watersheds with TMDLs. A requirement should be imposed for the permit applicant to identify to the Department when the discharge will occur in impaired waters, and what specific additional measures are being implemented to provide protection for the specific pollutants of concern. The Department should maintain specific records and documentation of HVHF activities in impaired waters. Additional monitoring and reporting requirements are warranted in impaired waters, and should be submitted to the Department, not just maintained on site.

Part III – DEVELOPMENT AND ADMINISTRATION OF THE CONSTRUCTION SWPPP

Comment 12:

A.3. Development of the Construction SWPPP – Section 5.1 of the RDSGEIS identifies a number of types of land disturbance activities associated with HVHF including utility corridors (including gathering lines), compressor facilities, and access roads associated with compressor facilities. However, the construction of gathering lines, compressor facilities and the access roads associated therewith is not required to be addressed in the SWPPP. The GP and the required SWPPP contents should be revised to include construction and stormwater discharges related to gathering lines, compressor stations and associated access roads, as well as those facilities currently listed under this section.

Comment 13:

C.1. Disturbance of more than five (5) acres – If phased construction is planned,

with a maximum of five acres disturbed in any phase, the permitting of greater disturbance may be permissible under the SPDES HVHF GP as it is currently written.

Recommendation: The SPDES HVHF GP should be revised to require approval when the soil disturbance activities will result in more than five acres of disturbance at any one time, or more than five acres of disturbance over the life of the project.

Recommendation: The SPDES HVHF GP should be revised to effectively cover all areas not in AA, AA-Special, or FAD areas.

Part IV CONTENTS OF SWPPP

Comment 14:

A. What the Construction SWPPP Must Achieve –The SPDES HVHF GP requires well sites to be *designed to minimize environmental impacts* through the minimization of clearing and grading; and avoidance of sensitive areas such as erodible soils, steep areas, and critical habitats. However, the SPDES HVHF GP does not indicate how the permittee will achieve this.

Recommendation: The SPDES HVHF GP should be revised to clearly indicate how sensitive areas will be identified in permittee submission packages and require the identification to be done so at a mapping scale adequate to clearly identify all potential sensitive areas to ensure clearing and grading will be minimized accordingly. This requirement also applies to setback requirements around waterbodies. (See additional comments under Part IV.C.1. and Part IV.A.)

Comment 15:

B.1.b. and e. Effluent Limitation Requirements – The SPDES HVHF GP requires compliance with erosion and sediment controls to *minimize the discharge of pollutants,* specifically the control of stormwater and sediment discharges, but does not require supporting calculations to be submitted.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit calculations supporting any claim of compliance with mandatory control of stormwater, sediment, or other pollutant discharges.

Comment 16:

C.1.b. Erosion and sediment control components - The SPDES HVHF GP requires a site map/construction drawing(s) that include information vital to erosion and sediment control considerations, including wetlands, potentially affected surface waters, existing and final slopes, and location(s) of stormwater discharges. However, there is no maximum scale identified for this requirement. It is possible that sensitive features may be overlooked and steep slopes unidentified if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification of features to be avoided or protected during construction.

Comment 17:

C.1.i. Erosion and sediment control components – The inspection schedule, as well as the corresponding inspection reports should be made available with the SWPPP for Department access. At a minimum, the inspection schedule should be made available to the public and include a Department contact where concerns may be reported.

Comment 18:

D.1.b. Post-construction stormwater management practice component - The SPDES HVHF GP requires a well site map/construction drawing(s) that include information vital to post-construction stormwater management practice evaluation,

including the specific location and size of each post-construction stormwater management practice. However, there is no maximum scale identified for this requirement. It is possible that the regulatory review of post-construction stormwater management practices may be inadequate if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification and evaluation of proposed post-construction stormwater management practices.

Comment 19:

D.1.e. Post-construction stormwater management practice component - The SPDES HVHF GP requires a hydrologic and hydraulic analysis for all structural components of the stormwater management control system. However, the SPDES HVHF GP does not require supporting calculations to be submitted in support of these analyses. Without supporting calculations, regulators will be limited in the ability to effectively review the appropriateness of the proposed system.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit calculations supporting the hydrologic and hydraulic analysis of all structural components of the proposed stormwater management control system. All calculations and information should be available to the public upon request.

Comment 20:

D.1.f. Post-construction stormwater management practice component – The SPDES HVHF GP requires a detailed summary of the sizing criteria that were used to design all post-construction stormwater management practices *including calculations* to be submitted with the SWPPP. The SPDES HVHF GP requires the summary to address, at a minimum, the required design criteria from applicable chapters of the 2010 New York State Stormwater Management Design Manual.

However, the SPDES HVHF GP does not indicate that the calculations are site specific. Given the variability of site conditions throughout any given project, it is essential that the post-construction stormwater management practices be designed to address the unique considerations of both the site conditions and the functional practicality of any proposed post-stormwater management practice.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit site-specific calculations supporting the design of all proposed stormwater management practices to ensure they are appropriate for site-specific conditions.

Comment 21:

E. Enhanced Phosphorous Removal Standards – The SPDES HVHF GP requires post-construction stormwater management practices to be designed in conformance with the Enhanced Phosphorous Removal Standards included in the 2010 New York State Stormwater Design Manual. However, the SPDES HVHF GP does not require permittees to submit documented implementation of this requirement.

Recommendation: The SPDES HVHF GP should be revised to require permittees to document the implementation of the Enhanced Phosphorous Removal Standards within the SWPPP as part of their permit application package.

Part V-CONSTRUCTION OF WELL SITE – INSPECTION, MAINTENANCE, AND RECORDKEEPING REQUIREMENTS

Comment 22:

D. Recordkeeping – The SPDES HVHF GP requires all inspection reports to be maintained on the *well site* with the *Construction SWPPP*. Without a requirement to submit inspection reports or, at a minimum, a list of violations and corrective actions required, to the Department, the inspection reports may not serve their

intended purpose. Regardless of limitations to staff and funding, the Department should maintain responsibility for ensuring compliance with applicable regulations. The utilization of *qualified inspectors* is only one part of ensuring compliance and should be supplemented with quality control checks by the Department, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of inspection reports or, at a minimum, a list of violations and correctives actions required, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of inspection documents to ensure compliance is being achieved.

Part VI CONSTRUCTION PHASE COMPLETION

Comment 23:

B. Inspections – The SPDES HVHF GP requires from qualified inspectors, by signature, a statement certifying achievement of final site stabilization. However, the SPDES HVHF GP does not require any documentation supporting this certification.

Recommendation: The SPDES HVHF GP should be revised to require documentation, specifically time/date-stamped digital photographs, to support certification of final stabilization.

Part VII HVHF SWPP

Comment 24:

Part VII General comment – Would an applicant be permitted to submit one

generic document to be applied at multiple sites? If so, it is unlikely that all relevant issues will be adequately addressed.

Recommendation: The SPDES HVHF should be revised to require a site-specific SWPPP as described in previous comments to ensure adequate protection and mitigation measures are proposed.

Comment 25:

A.5. Development of the HVHF SWPPP – The SPDES HVHF GP requires the HVHF SWPPP to be developed by someone knowledgeable in the principles and practices of stormwater management and groundwater protection associated with the HVHF Phase and the Production Phase. The SPDES HVHF GP specifically mentions a Professional Engineer. However, the principles and practices of groundwater protection are often best performed by a Professional Hydrogeologist.

Recommendation: The SPDES HVHF GP should be revised to reference the appropriate professional disciplines necessary to adequately address both stormwater management (Professional Engineer) and groundwater protection (Professional Hydrogeologist).

Comment 26:

A.11 Development of the HVHF SWPPP – The SPDES HVHF GP allows the Department to issue an immediate stop work order upon a finding of significant non-compliance of the HVHF SWPPP or violation of the GP.

Recommendation: The ability to issue a stop-work order is a great option for the Department and should be supplemented by random quality control reviews performed as described in previous comments.

Part VIII HVHF OPERATION REQUIREMENTS

Comment 27:

A.1. and 2. General Requirements – The SPDES HVHF GP requires owners and operators to develop and evaluate alternatives for HVHF Phase fluid additives and to maintain a list of all HVHF Phase fluid additives on-site. The Department must make clear that propriety information must not be excluded from this list.

Comment 28:

A.4. General Requirements – The SPDES HVHF GP requires qualified inspectors to sign a statement certifying achievement of final site stabilization prior to initiating the HVHF Phase. However, the SPDES HVHF GP does not require any documentation supporting this certification.

Recommendation: The SPDES HVHF GP should be revised to require documentation, specifically time/date-stamped digital photographs, to support certification of final stabilization.

Comment 29:

A.6. General Requirements – The SPDES HVHF GP requires Department inspector verification of partial site reclamation. However, the SPDES HVHF GP does not address the procedures necessary if partial site reclamation is not sufficient.

Recommendation: The SPDES HVHF GP should be revised to detail the process for addressing sites where the requirements for partial site reclamation are insufficient.

Part IX CONTENTS OF THE HVHF SWPPP

Comment 30:

A.2. HVHF General SWPPP Requirements – The SPDES HVHF GP requires a site map that includes information critical to adequately review and evaluate the HVHF

SWPPP. Specifically, the SPDES HVHF GP cites a *USGS quadrangle or other map.* While a USGS quadrangle map may be adequate for showing general site location, it is not appropriate for showing detailed information. It is possible that the regulatory review of the HVHF SWPPP may be inadequate if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification and evaluation of proposed post-construction stormwater management practices. Specifically, this section of the SPDES HVHF GP should be revised as follows:

b. Directions of stormwater flow should be shown on a contoured map with contours shown at minimum 5-ft intervals.

e. The scale for maps showing the locations of items listed in this section should be mapped at an appropriate defined scale (e.g. 1"=50' maximum). This section should also include the location of gathering lines.

g. Drainage area maps and stormwater outfall locations should be submitted on a separate stormwater map, attached to the site map, to ensure correct documentation.

i. The procedure for determining areas with significant potential for causing erosion should be defined or, if already defined in other documents, referenced.

Comment 31:

A.4. HVHF General SWPPP Requirements – This section requires the name, classification, and distance from the nearest edge of the well pad to the nearest receiving water(s). Submission of this information in narrative form may be sufficient, but an appropriately scaled map with labeled features would also provide an easily-verifiable document.

Recommendation: The SPDES HVHF GP should be revised to require a map showing the name, classification, and distance from the nearest edge of a well pad to the nearest receiving water(s) at a legible scale.

Comment 32:

A.7. HVHF General SWPPP Requirements – The inclusion of gravel is important when considering the total imperviousness of the well site. The compaction of subsoils and clogging with fine sediment within gravel areas has been shown to function as an impervious surface with regard to stormwater runoff.

Comment 33:

A.7. HVHF General SWPPP Requirements – This section includes an equation for estimating the total imperviousness of a well site as:

> Area of Roofs + Area of Paved and Other *Impervious* Surfaces, including gravel and roads = Total Area of *Well site.*

This equation should be revised as follows:

> Area of Roofs + Area of Paved and Other *Impervious* Surfaces, including gravel and roads = Total Impervious Surface Area of *Well site.*

Comment 34:

A.11. HVHF General SWPPP Requirements – The SPDES HVHF GP requires a summary of discharge sampling data to be maintained on the well site. Without a requirement to submit sampling data to the Department, it is possible that discharges in violation of the SPDES HVHF GP may be overlooked. Regardless of limitations to staff and funding, the Department should maintain responsibility for compliance and enforcement through quality control checks.

Recommendation: Quality control checks should be performed by the Department and facilitated by the submission of sampling data to the Department electronically. Checks should then be verified through cross-checking submitted sampling data

against Department-collected sample data. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Comment 35:

A.13. HVHF General SWPPP Requirements – In addition to identifying the proposed sources or any water to be used at the well site, an estimate of proposed volume to be withdrawn from each source will assist in tracking any pollutants found in that water.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit estimated volumes to be withdrawn from each identified water source.

Comment 36:

A.16. HVHF General SWPPP Requirements – The SPDES HVHF GP requires the HVHF SWPPP to include a description of stormwater management controls appropriate for the *well site*. However, the SPDES HVHF GP does not indicate that this description will include site specific sizing calculations. Given the variability of site conditions throughout any given project, it is essential that stormwater management controls be designed to address the unique considerations of both the site conditions and the functional practicality thereof.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit site specific sizing calculations supporting the design of all proposed stormwater management controls to ensure they are appropriate for site-specific conditions. Site-specific stormwater management controls should be evaluated for design and performance through inspection reporting and quality control as described in previous comments.

Comment 37:

A.18.k. HVHF General SWPPP Requirements – The SPDES HVHF GP requires the HVHF SWPPP to include information about partial site reclamation, including a requirement that reclaimed areas be seeded and mulched after topsoil replacement and reestablishment of vegetative cover. Standards for acceptable seeding, maintenance of seeded areas, and soil restoration should be defined in order to ensure reclamation, revegetation, and continued stabilization are achieved.

Recommendation: The SPDES HVHF GP should be revised to include by definition or reference standards for acceptable seeding, maintenance of seeded areas, and soil restoration.

Comment 38:

B.1.p. Required Non-Structural BMPs - The SPDES HVHF GP requires the owner or operator to use absorbents for dry cleanup whenever possible. However, the SPDES HVHF GP does not address the disposal of used absorbents.

Recommendation: The SPDES HVHF GP should be revised to address the disposal of used absorbents in accordance with NYS and EPA guidelines.

Comment 39:

C. Required Structural BMPs – The SPDES HVHF GP requires the HVHF SWPPP to "describe the traditional stormwater management practices…that currently exist or that are planned." However, the SPDES HVHF GP does not require calculations supporting the capacity of existing stormwater management practices to manage additional stormwater from newly constructed well sties, nor does the SPDES HVHF GP require supporting calculations for design of proposed stormwater management practices. Without a thorough review prior to issuance of the GP, it is possible that stormwater management practices will be inadequate to effectively address stormwater runoff from well sites.

Recommendation: - The SPDES HVHF GP should be revised to require the submission of calculations supporting the capacity of existing stormwater management practices and the design of proposed stormwater management practices to effectively manage stormwater runoff resulting from the construction and operation of a well site.

Part X ACTIVITIY-SPECIFIC STRUCTURAL AND NON-STRUCTURAL BMPs AND BENCHMARK MONITORING REQUIREMENTS

Comment 40:

A.5. General – The SPDES HVHF GP states that "if the [HVHF] activities are conducted for less than one (1) calendar year, all stormwater monitoring requirements must be satisfied during the period of activity. If no qualifying storm event occurs during the period of activity, or no qualifying storm event results in a *discharge*, monitoring requirements must be completed during the first qualifying storm that results in a *discharge*." However, the SPDES HVHF GP does not define the term "qualifying storm event." To ensure adequate monitoring of stormwater resulting from HVHF activities, the monitoring and sampling requirements must be clearly defined in order for permittees to satisfy the conditions of the permit.

Recommendation: The SPDES HVHF GP should be revised to include a clear definition of the term "qualifying storm event."

Comment 41:

D. Vehicle and equipment cleaning areas – The SPDES HVHF GP states that "discharge of vehicle and equipment wash waters … are not authorized by the SPDES HVHF GP and must be covered under a separate SPDES permit or discharged to a sanitary sewer in accordance with applicable industrial pretreatment requirements or transported off-site for proper disposal." The intent of the SPDES HVHF GP was to streamline and condense the permitting process for HVHF

activities. Requiring a separate permit for the discharge of vehicle and equipment wash waters seems redundant in light of the ability of the SPDES HVHF GP to cover all other HVHF activities.

Recommendation: The SPDES HVHF GP should be revised to incorporate all the provisions necessary to meet New York State permitting requirements within a single permit, including the provisions necessary to authorize discharges from vehicle and equipment wash waters or require off-site transportation for disposal.

Comment 42:

J. Piping/conveyances – The SPDES HVHF GP requires the HVHF SWPPP to include and describe measures that prevent or minimize the contamination of surface runoff from spills and leaks from piping/conveyance systems used for transferring "fresh water, *flowback* water, *production brine*, well *stimulation* water, sanitary, and other wastewaters." However, the SPDES HVHF GP does not address this requirement for piping/conveyance systems used for transferring the gas produced by each well site. Failure to address the piping/conveyance systems used for gas transmission may result in inadequate protection of surface waters in the event of a leak or spill of gas.

Recommendation: The SPDES HVHF GP should be revised to address all piping/conveyances, including gas transmission systems.

Comment 43:

J.2.p. Piping/conveyances – The SPDES HVHF GP states, "pipelines buried under stream crossings shall be buried below the scouring depth and may require other permits." The SPDES HVHF GP does not require the submission of supporting calculations for determination of scour depth, nor does it clearly define the conditions under which "other permits" may be required. Furthermore, it seems that NYSDEC does not require stream crossing permits for activities other than silviculture. This lack of oversight may result in significant impacts to surface

waters due to the potential thousands of crossings at headwater streams to facilitate HVHF activities.

Recommendation: The SPDES HVHF GP should be revised to require submission of calculations supporting the determination of scour depth for the placement of buried pipeline stream crossings.

Recommendation: The SPDES HVHF GP should be revised to clearly define which "other permits" may be required and the conditions under which those "other permits" are applicable.

Recommendation: NYSDEC should examine current stream crossing requirements and develop more robust regulations to ensure proposed crossings are constructed and maintained appropriately and do not impact water quality.

Comment 44:

M. Freshwater Surface Impoundments and Reserve Pits – The SPDES HVHF GP states, "a closed-loop tank system must be used instead of a reserve pit to manage drilling fluids and cuttings for any of the following: a) horizontal drilling in the Marcellus Shale unless an acid rock drainage mitigation plan for onsite burial of such cuttings is approved by the Department; and; b) any drilling requiring cuttings to be disposed of off-site, as provided in Part 360 of this Title, including at a landfill." However, the SPDES HVHF GP does not define an "acid rock drainage mitigation plan." The SPDES HVHF GP also does not clearly identify the reference to Part 360 in section (b), above.

Recommendation: The SPDES HVHF GP should be revised to include a section defining an "acid rock drainage mitigation plan" which includes the conditions under which the plan must be developed, the issues which the plan must address (including any necessary supporting calculations), and the contents which must be included in the plan.

Recommendation: The SPDES HVHF GP should be revised to clearly identify the statute included in part (b) of this section which references the off-site disposal of cuttings.

Part XII HVHF PHASE MONITORING

Comment 45:

A. Schedule for Monitoring – The SPDES HVHF GP requires a schedule for visual monitoring and examination of stormwater discharges at each outfall after each qualifying storm that must document observed color, odor, clarity, floating solids, settled solids, suspended solids, foam, and oil sheen. However, the SPDES HVHF GP does not require sampling, even if the visual observations indicate the presence of pollutants.

Recommendation: The SPDES HVHF GP should be revised to clearly define sampling requirements. At a minimum, sampling and laboratory testing should be required if a visual examination indicates the presence of pollutants.

Comment 46:

A. Schedule for Monitoring – The SPDES HVHF GP requires visual examination documents to be maintained on the well site. Also, the SPDES HVHF GP does not require photographic documentation to support visual examination reports. The Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of visual examination reports, including photos, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be

accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of visual examination documents to ensure compliance is being achieved.

Comment 47:

A. Schedule for Monitoring – The SPDES HVHF GP states, "all samples (except snowmelt samples) must be collected from the *discharge* resulting from a storm event that is greater than 0.1 inches in magnitude and that occurs at least seventy-two (72) hours from the previously measurable (greater than 0.1 inch rainfall) storm event. The 72-hour storm interval is waived if the preceding measurable storm did not result in a stormwater *discharge* (e.g., a storm event in excess of 0.1 inches may not result in a stormwater *discharge* at some facilities)." Is this the intended definition of "qualifying storm event?"

Comment 48:

A. Schedule for Monitoring – The SPDES HVHF GP states, "if a visual examination was performed and the storm event was later determined not to be a measurable (greater than 0.1 inch rainfall) storm event, the visual examination should still be included in the *HVHF SWPPP* records." The inclusion of all visual examination reports in the HVHF SWPPP record should be required.

Recommendation: The SPDES HVHF GP should be revised to state, "if a visual examination was performed and the storm event was later determined not to be a measurable (greater than 0.1 inch rainfall) storm event, the visual examination must still be included in the *HVHF SWPPP* records."

Comment 49:

A.3.c. Schedule for Monitoring – This section of the SPDES HVHF GP requires samples to be analyzed within ten calendar days after they have been collected.

This information may be more logically located in section A.10.b. which discusses collection and analysis of samples.

Recommendation: The SPDES HVHF GP should be revised to move the above referenced requirement for analysis of samples from Part XII.A.3.c. to Part XII.A.10.b.

Comment 50:

A.3.d. Schedule for Monitoring – This section of the SPDES HVHF GP states, "the benchmark concentrations do not constitute direct numeric effluent limitations and, therefore, an exceedance is not a general permit violation." What is the purpose of benchmark monitoring if exceedance of the benchmark concentrations listed in Part X of the SPDES HVHF GP do not result in a general permit violation?

Recommendation: The SPDES HVHF GP should be revised to omit this sentence from the document. Exceeding benchmark concentrations should immediately result in a violation of the GP to ensure proper corrective action is taken to protect water quality.

Comment 51:

A.3.f. Schedule for Monitoring – The SPDES HVHF GP requires benchmark monitoring results to be documented and maintained on the well site. The Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of benchmark monitoring results, including corrective actions needed, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should

also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of benchmark monitoring documents to ensure compliance is being achieved.

Comment 52:

A.10.b. Schedule for Monitoring – The SPDES HVHF GP states that "sampling requirements must be assessed on an outfall-by-outfall basis." However, there are no criteria upon which sampling requirements are to be assessed. The SPDES HVHF GP also fails to identify the party responsible for directing sampling requirements at each outfall. Sampling requirements should be directed by NYSDEC guidance criteria, to include frequency of collection and analysis requirements.

Recommendation: The SPDES HVHF GP should be revised to clearly identify the Department as the party responsible for directing sampling requirements at each outfall.

Recommendation: The NYSDEC should develop guidance criteria for sampling requirements for HVHF activities. This guidance criteria should address the conditions under which sample collection is required (i.e., when a visual examination indicates the presence of pollution), location of sample collection, frequency of sample collection, and laboratory analysis requirements for collected samples.

Recommendation: The SPDES HVHF GP should be revised to require sampling in accordance with NYSDEC guidance criteria, to include frequency of collection and analysis requirements.

Comment 53:

A.10.b. Schedule for Monitoring – This section of the SPDES HVHF GP does not reference the ten-day time limit for analysis of collected samples.

Recommendation: This section of the SPDES HVHF GP should be revised to include reference to the ten-day time limit for analysis of collected samples included in Part XII.A.3.c.

Comment 54:

A.10.c. Schedule for Monitoring – This section of the SPDES HVHF GP requires owners/operators to provide the date and duration of sampled storm events, rainfall measurements or estimates (in inches) of the storm event that generated the sampled runoff, time between storm events greater than 0.1 inch, and an estimate of volume sampled. A rain gauge/weather station should be required to ensure rainfall greater than 0.1 inch is accurately recorded. This will also ensure visual examination and sampling is completed for events greater than 0.1 inch.

Recommendation: The SPDES HVHF GP should be revised to require rainfall measurements and remove references to rainfall estimates to ensure monitoring and sampling in compliance with the conditions of the permit.

Part XIII HVHF PHASE REPORTING

Comment 55:

A. Discharge Monitoring Reports (DMR) – The SPDES HVHF GP requires the results of laboratory analysis of samples to be submitted to the Department on preprinted DMRs within ten days of their receipt. The required formatting of DMRs lends itself very easily to standardization for electronic submission to the Department, which would allow for faster submission and reduce the costs incurred by both the Department and permittees by eliminating unnecessary paper and paperwork. Furthermore, the Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of DMRs, in approved format via online forms, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of benchmark monitoring documents to ensure compliance is being achieved.

Part XIV MONITORING FOR THE PRODUCTION PHASE AND TEMPORARY SUSPENSION OF THE HVHF PHASE

Comment 56:

A. Schedule for Monitoring – Please see comments 45, 46, 49, 50, 51, 52, 53, and 54, and the corresponding recommendations as they apply to this section of the SPDES HVHF GP.

Part XVI PRODUCTION PHASE REPORTING

Comment 57:

A. Discharge Monitoring Reports (DMR) – Please see comment 55 and the corresponding recommendation as it applies to this section of the SPDES HVHF GP.

Part XXI. STANDARD GENERAL PERMIT CONDITIONS

Comment 58:

F. Duty to Provide Information – The SPDES HVHF GP states, "the NOI, SWPPP and inspection reports required by this general permit are public documents that the *owner or operator* must make available for review and copying by any person within five (5) business of the *owner or operator* receiving a written request by any such

person to review the NOI, SWPPP or inspection reports. Copying of documents will be done at the requester's expense." Many HVHF well sites prohibit access by the general public, and all of the public documents indicated are required by the SPDES HVHF GP to be kept on the well site. In order to expedite requests and eliminate man-hours necessary to escort individuals through restricted areas, as well as provide for the recommendations above, the Department should require the electronic submission of all public documents. These documents should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Recommendation: The SPDES HVHF GP should be revised to allow for the electronic submission of all public documents. These documents should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Attachment A

Technical Information in support of comments:

1. Sediment Loads from Gravel Roads

   The Pennsylvania Center for Dirt and Gravel Road Studies provides information on measures to maintain gravel roads in a manner to reduce the discharge of pollutants and protect water quality. Penn State's Center for Dirt and Gravel Road Studies (Center) recently completed a research project for the Chesapeake Bay Commission (Scheetz, Summary Statement) that begins to quantify sediment production from gravel roads and sediment reductions from several commonly used practices. This study found that:

   > **Runoff Rates from Existing Roads:**
   > *"The five "existing condition" tests done for this study found sediment production rates ranging from 0.7-12.2 pounds of sediment runoff in a single 30 minute, 0.55 inches simulated rainfall. The 0.7 pound event was generated from a flat narrow farm lane with grass growing between the wheel tracks. The 12.2 pound event was generated from a wider, mixed limestone/clay road at a 4-5% slope. This highlights the great variability in erosion rates based on specific site conditions. Using the average sediment runoff rate of 5.6 pounds per event, a single 30 minute 0.55 inch rain event moving across Pennsylvania can be conservatively expected to generate over 3,000 tons* of sediment form the State's 20,000+ miles of public unpaved roads".*

   This research supports that gravel roads can be a significant source of pollutants such as sediment. As discussed in several comments, there is a need for the RDSGEIS to estimate the cumulative impact of gravel road development as a result of HVHF activity.

2. **Water Quality Impacts from Gas Drilling Activities**

   In 2005, the U.S. Environmental Protection Agency (U.S. EPA) awarded a grant to the City of Denton, Texas, to monitor and assess the impact of gas well drilling on stormwater runoff. The results of this effort were published in December 2007

in a report titled "Demonstrating the Impacts of Oil and Gas Exploration on Water Quality and How to Minimize These Impacts Through Targeted Monitoring Activities and Local Ordinances." With regards to the discharge of sediment during construction, this study determined that:

> *"Gas well sites have the potential to produce sediment loads comparable to traditional construction sites.*
>
> - *Total suspended solids (TSS) and turbidity event mean concentrations (EMC = pollutant mass / runoff volume) at gas sites were significantly greater than at reference sites (the median TSS EMC at gas sites was 136 times greater than reference sites).*
>
> - *Compared to the median EMCs of storms sampled by Denton near one of their outfalls, the gas well site median EMC was 36 times greater.*
>
> - *Gas site TSS EMCs ranged from 394 to 9898 mg/l and annual sediment loadings ranged from 21.4 to 40.0 tonnes/hectare/year (tonne = 1000 Kg; hectare = 10,000 square meters), and were comparable to previous studies of construction site sedimentation"*.

This study concludes that "Gas well sites have the potential to negatively impact surface waters due to increased sedimentation rates." (US EPA ID No. CP-83207101-1, page 2).

In addition to the well pad site, roads that are constructed, widened, or altered for vehicle access to and from the well pad site can be a source of sediment and pollutants during both construction and operation. The U.S. EPA Publication "Erosion, Sediment and Runoff Control for Roads and Highways" (EPA-841-F-95-008d) states that:

> Runoff controls are essential to preventing polluted runoff from roads, highways, and bridges from reaching surface waters. Erosion during and after construction of roads, highways, and bridges can contribute large amounts of sediment and silt to runoff waters, which can deteriorate water quality and lead to fish kills and other ecological problems.
>
> Heavy metals, oils, other toxic substances, and debris from construction traffic and spillage can be absorbed by soil at construction sites and carried with runoff water to lakes, rivers,

and bays. Runoff control measures can be installed at the time of road, highway, and bridge construction to reduce runoff pollution both during and after construction. Such measures can effectively limit the entry of pollutants into surface waters and ground waters and protect their quality, fish habitats, and public health.

This publication (EPA-841-F-95-008d) identifies a number of pollutant types and sources related to Roads and Highways, as identified in Table 1.

Table 1. Typical pollutants found in runoff from roads and highways.

Erosion, Sediment and Runoff Control for Roads and Highways | Polluted Runoff | US EPA

	Pollutant	**Source**
Sedimentation	Particulates	Pavement wear, vehicles, the atmosphere and maintenance activities
Nutrients	Nitrogen & Phosphorus	Atmosphere and fertilizer application
Heavy Metals	Lead	Leaded gasoline from auto exhausts and tire wear
	Zinc	Tire wear, motor oil and grease
	Iron	Auto body rust, steel highway structures such as bridges and guardrails, and moving engine parts
	Copper	Metal plating, bearing and brushing wear, moving engine parts, brake lining wear, fungicides & insecticides
	Cadmium	Tire wear and insecticide application
	Chromium	Metal plating, moving engine parts and brake lining wear
	Nickel	Diesel fuel and gasoline, lubricating oil, metal plating, bushing wear, brake lining wear and asphalt paving
	Manganese	Moving engine parts
	Cyanide	Anti-caking compounds used to keep deicing salt granular
	Sodium, calcium & chloride	Deicing salts
	Sulphates	Roadway beds, fuel and deicing salts
Hydrocarbons	Petroleum	Spills, leaks, antifreeze and hydraulic fluids and asphalt surface leachate

References

1. Center for Rural Pennsylvania "the Impact of Marcellus Gas drilling on Rural Drinking Water Supplies", October 2011.

2. Entrekin, Sally, et al, "Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters", From Frontiers in Ecology 2011; 9(9): 503-511, Oct 2011.

3. Etowah Aquatic Habitat Conservation Plan "Utility Stream Crossings Policy", July 13, 2006.

4. Handlerof, Stephanie; League of Women Voters of Indiana "Marcellus Shale Natural Gas Extraction Study 2009-2010 Study Guide V: Regulation and Permitting of Marcellus Shale Drilling", League of Women Voters of Pennsylvania, 2010.

5. Kaplan, Louis, et al "Protecting Headwaters: The Scientific Basis For Safeguarding Stream And River Ecosystems, A Research Synthesis from the Stroud Water Research Center " 2008.

6. Leopold, Luna B.; "A View of the River", Harvard University Press, Cambridge, MA, 1994.

7. NYDEC "Stream Crossings Protecting and Restoring Stream Continuity" web page at http://www.dec.ny.gov/permits/49060.html.

8. O'Dell, Patrick M., Professional Engineer in Petroleum Engineering, National Park Service Geologic Resources Division, "Potential for Development of Natural Gas Exploratory Wells to Adversely Affect Water Resources of the Delaware River Basin", Nov 23, 2010.

9. Reid, Scott M. and Paul G. Anderson "Effects of Sediment released During Open-cut Pipeline Water Crossings, Canadian water Resources Journal Vol. 24, No 3, 1999.

10. Scheetz, Dr. Barry E. and Steven M. Bloser; Center for Dirt and Gravel Road Studies, The Pennsylvania State University, University Park, PA 16802; "Environmentally Sensitive Maintenance Practices for Unpaved Roads: Sediment Reduction Study" Prepared for Chesapeake Bay Commission c/o Senate of Pennsylvania G-05 North Office Building Harrisburg, PA 1712, FINAL REPORT June 30, 2008, Revised August 29, 2008 and Summary Statement

11. United States Environmental Protection Agency "Erosion, Sediment and Runoff Control for Roads and Highways", Office of Water (4503F) EPA-841-F-95-008d, December 1995

12. United States Environmental Protection Agency, Final Report for Catalog of Federal Domestic Assistance Grant Number 66.463 Water Quality Cooperative Agreement for Project Entitled "Demonstrating the Impacts of Oil and Gas Exploration on Water Quality and How to Minimize these Impacts Through Targeted Monitoring Activities and Local Ordinances" and "Summary of the Results of the Investigation Regarding Gas Well Site Surface Water Impacts", ID No. CP-83207101-1, Kenneth E. Banks, Ph.D. Manager, Division of Environmental Quality and David J. Wachal, M.S. Water Utilities Coordinator

13. United States Environmental Protection Agency, Wadable stream assessment: a collaborative survey of the nation's streams, 2006. EPA 841-B-06-002.

14. Letter from James A. Schmid, PhD, Schmid & Company Consulting Ecologists to Scott E. Walters, Chief General Permits Bureau of Waste Management PaDEP, 8 November 2011.

Attachment 7

The Louis Berger Group, Inc.

THE Louis Berger Group, INC.
48 Wall Street, 16th Floor, New York, NY 10005
Tel 212 612 7900 Fax 212 363 4341
www.louisberger.com

Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Review Comments on the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations (Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560)

1.0 Introduction

The Louis Berger Group Inc. (LBG) reviewed the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS), the proposed Environmental Assessment Form (EAF) and EAF Addendum (RDSGEIS Appendices 5 and 6), the proposed Supplemental Permit Conditions (RDSGEIS Appendix 10) and the proposed High-Volume Hydraulic Fracturing (HVHF) regulations (Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560) for the following topics:

- Noise (RDSGEIS Sections 2.4.13 and 6.10)
- Ground-borne noise and vibration (impacts not addressed in the RDSGEIS)
- Visual impacts (RDSGEIS Sections 2.4.12 and 6.9)
- Land use (impacts not addressed in the RDSGEIS)
- Transportation (RDSGEIS Sections 2.4.14 and 6.11)
- Community character (RDSGEIS Sections 2.4.15 and 6.11)
- Cultural resources (impacts not addressed in the RDSGEIS).
- Aquatic Ecology (RDSGEIS Sections 6.1.1.2, 6.1.1.3 and 6.1.1.4).

For each topic, the following sections address the sufficiency of the RDSGEIS impact analyses and proposed mitigation measures in meeting State Environmental Quality Review Act (SEQRA--6 NYCRR Part 617) requirements. The comments also identify specific improvements and best practice approaches that the New York State Department of Environmental Conservation (NYSDEC) could use to resolve the deficiencies identified and minimize the environmental impacts of High-Volume Hydraulic Fracturing (HVHF) and related development in New York.

2.0 Noise

2.1 Construction Impacts

The 2011 RDSGEIS quantitative construction noise assessment uses information from the Federal Highway Administration's Road Construction Noise Model to estimate noise

levels at various distances from the construction site and represents a substantial improvement over the qualitative analysis in the 2009 Draft Supplemental Generic Environmental Impact Statement (DSGEIS). For quiet rural areas, the results show that construction activities would result in significant adverse impacts under NYSDEC criteria (increase of 6 dBA (A-weighted decibels) or more over existing conditions) at distances exceeding 2,000 feet.

The RDSGEIS provides the requisite construction noise analysis, but fails to appropriately evaluate and discuss the significance of the model results. Instead, a one sentence conclusion is provided: "Such levels would not generally be considered acceptable on a permanent basis, but as a temporary, daytime occurrence, construction noise of this magnitude and duration is not likely to result in many complaints in the project area."

Contrary to this statement, there is no regulatory requirement that access road construction and site preparation be limited to daytime hours. To mitigate this significant adverse impact, a prohibition on nighttime construction should be included in the HVHF regulations or supplemental permit conditions to avoid annoyance and sleep disturbance of nearby residences, along with other construction noise control best practices (See Section 2.6 infra).

Further, the assertion in the RDSGEIS that construction noise impacts are "temporary" ignores the likelihood of large number of wells and pads being concentrated in certain areas, as well as construction noise from related infrastructure development (pipelines, compressors, etc.). The cumulative construction noise impact has not been addressed.

In addition, noise-related complaints are not the appropriate basis for drawing conclusions about the significance of noise impacts under SEQRA because people (and wildlife) can be adversely affected by noise, but choose not to report it. NYSDEC should evaluate the significance of the construction noise impacts in relation to the duration, quality (tonal purity), time of day and year, background noise present, distance to the source, familiarity with the noise and other factors such as the setting. Studies have shown that each listener's subjective perception of appropriateness of a noise in a particular setting can be just as important to annoyance as the objective sound level.[1] Given the rural context of the majority of the areas where natural gas development is expected to occur, many residents and visitors to these areas would find heavy construction activity noise to be out of place and annoying. Construction noise adjacent to parks and other sensitive land areas where natural quiet is expected would be especially problematic and would contribute to adverse economic impacts not accounted

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[1]See: Blauert, J. 1986. "Cognitive and Aesthetic Aspects of Noise Engineering." In *Proceedings of Inter-Noise 86, Cambridge, Massachusetts, July 21–23*, volume 1, 5–13.

Kuwano, S., S. Namba, and H. Miura 1989 "Advantages and Disadvantages of A-weighted Sound Pressure Level in Relation to Subjective Impression of Environmental Noises."*Noise Control Engineering Journal* 33:107–115.

Carles, J.L., I. Lopez Barrio, J.V. de Lucio 1999 "Sound Influence on Landscape Values."*Landscape and Urban Planning* 43:191–200.
Ozawa, K., S. Ohtake, Y. Suzuki, and T. Sone 2003 "Effects of Visual Information on Auditory Presence," Acoustical Letter to Acoustical Science and Technology, 24(2), 97-99.

for in the 2011 RDSGEIS by making areas where gas development is occurring less attractive to visitors.[2]

2.2 Drilling and Fracturing Impacts

2.2.1 Failure to Analyze Multi-Well Pad Impacts

The general approach used in the RDSGEIS quantitative noise impact assessment is reasonable and consistent with the methodology recommended in NRDC's comments on the 2009 DSGEIS for evaluation of the impacts of drilling and fracturing of one horizontal well. However, it fails to analyze the impacts of multi-well pads, which is the primary form of development anticipated. Table 6-59 in the RDSGEIS presents the duration of various construction and operational phases for one well. Each well is estimated to take 28-35 days to drill, while fracturing is assumed to take up to five days. Since drilling or fracking of multiple wells is likely to occur simultaneously, the combined noise levels would be higher than those reported for a single well in the RDSGEIS.

The failure of the RDSGEIS to provide a noise impact assessment for the simultaneous drilling and fracturing of multiple wells is especially problematic because it is inconsistent with the scenario developed for the analysis of transportation impacts (page 6-305). The result of this inconsistency is that the noise impacts of drilling and fracturing are underestimated and do not reflect a reasonably foreseeable worst-case development scenario. The multi-pad horizontal well development scenario in the transportation section of the RDSGEIS assumed three rigs would be operated simultaneously over a 120 day period and that each rig would drill four wells (for a total of 12 wells at the site). With three rigs in operation at the same time, the combined noise level at a distance of 50 feet would be approximately 84 dBA, not 79 dBA as reported for one rig in the RDSGEIS (Table 6.56- Rotary Air Well Drilling).[3]

With respect to the fracturing phase, the RDSGEIS wording is unclear, but appears to suggest sequential fracturing (one well being fractured at a time for a total of 60 days of fracturing noise impacts). The RDSGEIS states "fracturing and completion of the four wells occurs sequentially and tanks are brought in once for all four wells" (page 6-305). This statement is confusing because the scenario being described involves a total of 12 wells, not four wells. If fracturing of multiple wells occurs simultaneously, then the duration of fracturing impacts would be less, but the combined noise level would be higher. For example, fracturing two wells at once would create a combined noise level 3 dBA higher than the fracturing of one well. When drilling and fracturing are occurring at the same time, the total noise level would be entirely driven by the much louder fracturing process (no increase in the total sound level because the difference between the two sound levels is greater than 10 dBA).

At a minimum, NYSDEC should analyze the noise impact from the same multi-pad well development scenario as used in the analysis of transportation impacts. NYSDEC should address the expected number of wells per multi-well site, the timing of drilling and fracturing at each well and the reasonable worst case noise levels that could result from the various combinations of drilling and fracturing at multiple wells on the same site.

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[2] Refer to Susan Christopherson's socioeconomics technical memorandum for more information on impacts to the tourism industry.

[3] Decibels are expressed on a logarithmic scale and thus cannot be added together directly.

2.2.2 Lack of Reasonable Noise Impact Significance Criteria

Similar to the construction impact assessment discussed in Section 2.1, the RDSGEIS presents the model results for the drilling and fracturing noise impacts without a SEQRA-compliant assessment of the significance of the results in various contexts where natural gas development is anticipated. The RDSGEIS does not include noise impact criteria against which the significance of the impacts can be assessed generically or at the site specific review level, which is contrary to the purposes of a GEIS. For information on a recommended framework for developing noise impact criteria, refer to Section 2.8.

The RDSGEIS references NYSDEC's noise policy ("Assessing and Mitigating Noise Impacts,"2001)[4], but this document has a number of significant problems that limit its usefulness in regulating noise. It discusses a 6 dBA increase as potentially significant, but does not define what averaging time period should be used in calculating the increase, does not account for increased sensitivity to noise occurring at night, and does not take into account the total level at the affected receptor. The policy also does not provide a standard for specific highly sensitive land uses, such as passive recreation parks and wilderness areas. The NYSDEC noise policy leaves too much discretion to individual analysts to ensure consistent application of noise control for an activity expected to have widespread and significant impacts across New York. Accordingly, an assessment as to the significance of the potential adverse noise impacts should be made independent of the 2001 policy.

The RDSGEIS acknowledges that drilling and fracturing would take place 24hours per day. People are much more sensitive to noise that occurs at night and interferes with sleep than to noise that occurs only during daytime activities. For this reason, community noise impact assessment metrics such as day-night sound levels (Ldn) apply a 10 dB penalty to sounds occurring at night in determining a 24-hour average energy sound level that better reflects human preferences. Background noise levels are also lower at night, further emphasizing the significance of the increase in sound levels attributable to drilling and fracturing. As noted above in the discussion of construction impacts, non-residential land uses in rural areas vital to the economic health of upstate New York such as parks, recreation areas and campgrounds would be especially sensitive to increases in sound levels.

2.2.3 Fracturing Noise Impacts Exceed Hearing Damage Thresholds

The noise levels associated with the fracturing process are of a relatively short duration on a per well basis (2-5 days), but are of an extremely large magnitude that could adversely affect human health:

- At a distance of 2,000 feet, the fracturing pump truck noise level of up to 72 dBA would be intrusive and interfere with normal conversation.
- At a distance of 500 feet, the fracturing pump truck noise level of up to 84 dBA approaches the level where hearing damage occurs (85 dBA for eight hours).

[4] http://www.dec.ny.gov/docs/permits_ej_operations_pdf/noise2000.pdf

- At a distance of 250 feet, the fracturing pump truck noise level of up to 90 dBA is in the range of noise levels where no more than 15 minutes of unprotected exposure is recommended to prevent damage to hearing.[5]
- At a distance of 50 feet, the fracturing pump truck noise level of up to 104 dBA is of a similar magnitude to a jet flyover at a distance of 1,000 feet and at a level where unprotected exposure over one minute poses a risk of permanent hearing loss.

For context in understanding the sound levels discussed above, Table 1 provides a summary of the decibel level of common sounds sources and the associated effects.

Table 1
Decibel Levels of Common Sound Sources

Sound	Noise Level (dB)	Effect
Jet Engines (near)	140	
Shotgun Firing Jet Takeoff (100-200 ft.)	130	
Rock Concerts (varies)	110–140	Threshold of pain begins around 125 dB
Oxygen Torch	121	
Discotheque/Boom Box Thunderclap (near)	120	Threshold of sensation begins around 120 dB
Stereos (over 100 watts)	110–125	
Symphony Orchestra Power Saw (chainsaw) Pneumatic Drill/Jackhammer	110	Regular exposure to sound over 100 dB of more than one minute risks permanent hearing loss.
Snowmobile	105	
Jet Flyover (1000 ft.)	103	
Electric Furnace Area Garbage Truck/Cement Mixer	100	No more than 15 minutes of unprotected exposure recommended for sounds between 90–100 dB.
Farm Tractor	98	
Newspaper Press	97	
Subway, Motorcycle (25 ft.)	88	Very annoying
Lawnmower, Food Blender Recreational Vehicles, TV	85–90 70–90	85 dB is the level at which hearing damage (8 hrs.) begins
Diesel Truck (40 mph, 50 ft.)	84	
Average City Traffic Garbage Disposal	80	Annoying; interferes with conversation; constant exposure may cause damage
Washing Machine	78	
Dishwasher	75	
Vacuum Cleaner, Hair Dryer	70	Intrusive; interferes with telephone conversation
Normal Conversation	50–65	
Quiet Office	50–60	Comfortable hearing levels are under 60 dB.
Refrigerator Humming	40	
Whisper	30	Very quiet
Broadcasting Studio	30	
Rustling Leaves	20	Just audible
Normal Breathing	10	

Source: http://www.nidcd.nih.gov/health/education/teachers/pages/common_sounds.aspx

The minimum setbacks in the proposed regulations (currently 100 feet from a residence) must be revised to protect the health and well-being of nearby residents during fracking. Landowners should not have the power to waive the minimum setback requirement. The

[5] http://www.nidcd.nih.gov/health/education/teachers/pages/common_sounds.aspx

landowners should not be presented with the temptation to trade their family's health for financial gain. An additional problem with granting landowners the ability to waive setback requirements is that tenants of a landowner's property would not have any say in the landowner's decision to waive setback requirements essential for health.

The drilling phase sound levels are substantially lower than the fracturing noise levels, but their duration is much longer (approximately one month of 24-hour drilling per well). Drilling sound levels would drop to below 70 dBA at a distance of 250 feet from the well pad. However, 70 dBA is still 40 dBA greater than the nighttime background sound level in rural areas of 30 dBA, further supporting the need for noise impact criteria and mitigation requirements to protect the soundscapes of rural areas

2.2.4 Other Comments

Tables 6.56, 6.57 and 6.58 are all incorrectly labeled as showing "estimated construction noise levels."

The equipment assumed in the analysis and sound levels associated with each piece of equipment are based on "confidential industry sources." NYSDEC should disclose the basis for the equipment assumptions and sound levels so that these important inputs can be independently validated.

Table 6.57 has footnote "2" for the rig drive motor and generator sound levels, but the explanation for footnote 2 is missing. In addition, it appears that footnote #1 on Table 6.57 should be associated with the "Distance in Feet/SPL (dBA)" portion of the table and not the sound levels associated with the top drive, draw works and triple shaker.

2.3 Transportation Noise Impacts

The RDSGEIS discusses the potential for noise impacts related to truck traffic, but fails to conduct a meaningful analysis of typical transportation noise impacts for various phases of well pad development. This failure is particularly problematic given that the detailed truck trip generation information necessary for conducting a traffic noise assessment was developed for the transportation section of the RDSGEIS.

NYSDEC should use the Federal Highway Administration's (FHWA) Traffic Noise Model (TNM) version 2.5 and the truck trip generation information to fully consider truck traffic noise impacts. While site-specific impacts cannot be assessed, NYSDEC could easily examine a hypothetical, yet realistic development scenario for one well. The analysis could look at one single public road segment from which the well site would be accessed. Receptors at various distances (50 feet to 1,000 feet) would help show the potential extent of the area where impacts could occur. A range of non-natural gas related background traffic on the modeled road could be considered to show how the increase in sound levels would be much higher for local roads with low traffic volumes than for roads with high volumes under existing conditions. Traffic noise impacts for the various receptor distances could be assessed using well established New York State Department of Transportation (NYSDOT) and FHWA criteria.[6]

[6]FHWA's noise impact assessment and mitigation procedures are defined under 23 CFR 772. NYSDOT's latest noise policy (revised April 2011) for implementing the FHWA requirements is

For the purposes of the SGEIS level of analysis, a number of simplifying, conservative assumptions could be employed in the TNM analysis (assuming flat terrain, no existing barriers, analyze one worst-case peak hour and one worst-case off-peak hour etc.). These assumptions would allow NYSDEC to complete a meaningful traffic noise analysis without extensive cost or delay to the review process.

2.4 Effects on Wildlife

Animals rely on sounds for communication, navigation, avoiding danger and finding food. Industrial and transportation noises associated with natural gas development create noise levels that can interfere with the sounds used by animals, which in turn can affect wildlife behavior and populations. The RDSGEIS acknowledges that noise could contribute to impacts on wildlife (page 6-68), but does not provide any analysis of this issue. NYSDEC should review the available scientific literature on this topic, qualitatively assess impacts and ensure appropriate mitigation measures are implemented. Key references to assist NYSDEC in this aspect of the environmental review are provided below:[7]

FHWA. Synthesis of Noise Effects on Wildlife Populations. http://www.fhwa.dot.gov/environment/noise/noise_effect_on_wildlife/effects/

Barber, J.R., K.R. Crooks, and K. Fristrup. 2010. The costs of chronic noise exposure for terrestrial organisms. Trends Ecology and Evolution 25(3): 180–189. Available at: http://www.sciencedirect.com/

Bayne, E.M., L. Habib and S. Boutin. 2008. Impacts of Chronic Anthropogenic Noise from Energy-Sector Activity on Abundance of Songbirds in the Boreal Forest. Conservation Biology 22(5) 1186-1193. Available at: http://oz.biology.ualberta.ca/faculty/stan_boutin/uploads/pdfs/Bayne%20etal%202008%20ConBio.pdf

Dooling R. J., and A. N. Popper. 2007. The effects of highway noise on birds. Report to the California. Department of Transportation, contract 43AO139. California Department of Transportation, Division of Environmental Analysis, Sacramento, California, USA. Available at: http://www.dot.ca.gov/hq/env/bio/files/caltrans_birds_10-7-2007b.pdf

Francis, C.D., C.P. Ortega and A. Cruz. 2009. Noise Pollution Changes Avian Communities and Species Interactions. Current Biology, Aug 25;19(16):1415-9 10.1016/j.cub.2009.06.052. Available at: http://www.sciencedirect.com/science/article/pii/S0960982209013281

Habib, L, E.M. Bayne and S. Boutin. 2007. Chronic industrial noise affects pairing success and age structure of ovenbirds Seiurus aurocapilla. Journal of Applied Ecology 44: 176-184. Available at: http://oz.biology.ualberta.ca/faculty/stan_boutin/ilm/uploads/pdfs/Habib%20etal%202

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available at https://www.dot.ny.gov/divisions/engineering/environmental-analysis/manuals-and-guidance/epm/repository/4_4_18Noise.pdf

[7] The suggested list of references is adapted from the USFWS paper entitled "The Effects of Noise on Wildlife." Available at: http://www.fws.gov/windenergy/docs/Noise.pdf

007%20JAE.pdf

Schaub, A, J. Ostwald and B.M. Siemers. 2008. Foraging bats avoid noise. The Journal of Experimental Biology 211: 3174-3180. Available at: http://jeb.biologists.org/cgi/content/full/211/19/3174

Swaddle, J.P. and L.C. Page. 2007. High levels of environmental noise erode pair preferences in zebra finches: implications for noise pollution. Animal Behavior 74: 363-368.

2.5 Cumulative Impacts

The RDSGEIS does not address the cumulative noise impacts of the anticipated natural gas development. Key considerations in developing a cumulative impact analysis for noise include the following:

- Analyze the cumulative noise impact of multi-well pads. The RDSGEIS analysis only addresses a single well.
- Analyze the cumulative noise impact from well site construction, drilling and fracturing in combination with the construction of pipelines and the operation of compressor stations. Pipelines and compressor stations are a reasonably foreseeable form of "induced growth" that needs to be considered.
- Examining the Ldn sound levels that would result at residences that are exposed to drilling, fracturing and truck traffic noise. The combination of these sources could result in impacts more significant than any individual source examined separately.
- Discuss regional-scale traffic noise impacts that would result from wide spread natural gas development and related economic development and temporary population growth.
- Discuss regional-scale noise impacts on human beings and wildlife, including the potential for disturbance of noise-sensitive species, such as the ovenbird (*Seiurus aurocapilla*).[8]

2.6 Mitigation

2.6.1 Mitigation for Construction Impacts

Construction noise impact mitigation is not addressed in Section 7.10 of the RDSGEIS. NYSDEC should require the use of construction noise mitigation best practices, such as those outlined in FHWA's Construction Noise Handbook. At a minimum, these measures should include:

- Requiring the use of construction noise control measures in construction contract documents. Specific noise levels can be established to ensure the protection of sensitive receptors.

[8] http://oz.biology.ualberta.ca/faculty/stan_boutin/ilm/uploads/pdfs/Habib%20etal%202007%20JAE.pdf

- Limitations on the time periods when construction could occur (e.g., prohibiting nighttime construction).
- Requiring the use of less noisy equipment and mufflers.
- Requiring temporary noise barriers when significant impacts cannot be addressed through other means.

2.6.2 Mitigation for Drilling, Fracturing and Transportation Impacts

The general types of noise mitigation measures for drilling, fracturing and trucking suggested in the RDSGEIS are reasonable, but there is no guarantee which measures, if any, will actually be required in specific circumstances. Therefore, it is likely that significant impacts will not be mitigated at the site level. In addition, the RDSGEIS states that detailed noise modeling and consideration of mitigation measures will only be required for receptors within 1,000 feet of the well pad. This requirement is illogical given the impact analysis results that show impacts extending beyond 2,000 feet. Under NYSDEC's proposed 1,000 feet distance for noise modeling, well operators could avoid assessing site specific impacts and mitigation by locating wells just beyond the 1,000 feet threshold. This could result in unmitigated significant adverse impacts for residences between 1,000 and 2,000+ feet from the well pad.

Table 2 summarizes the noise mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum or the proposed regulations. The mitigation measures not included in the EAF or regulations are not enforceable.

The proposed supplemental permit conditions (Appendix 10) state that NYSDEC can require noise mitigation "deemed necessary," but this is meaningless without a clear basis for determining when noise impacts that warrant mitigation occur. The proposed supplemental permit conditions do not contain any of the mitigation measures in Table 2 that were not addressed by the EAF or the regulations. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A), therefore it would be reasonable and consistent to also include many of the site-specific noise mitigation measures in Table 2 as supplemental permit conditions. A few of the mitigation measures in Table 2 are general enough that they should be incorporated in the proposed regulations, rather than as supplemental permit conditions. These are indicated in the "notes" column of Table 2.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate noise impacts at HVHF sites, and use this information to refine the noise mitigation requirements for future permit applications.

Table 2
Noise Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Compliance with regulatory spacing and siting restrictions. (7-128)	No	Yes (553.1)	No	
Unless otherwise required by private lease agreement, the access road must be located as far as practicable from occupied structures, places of assembly, and occupied but unleased property. (7-135)	Yes (A6-6)	Yes (560.6(a))	No	Regulation adds an additional qualifier where this provision potentially does not apply- to avoid bisecting agricultural land.
The well operator must operate the site in accordance with a noise impacts mitigation plan consistent with the SGEIS. (7-135)	Yes (A6-6)	No	No	Applies to all wells, should be in regulations
The operator's noise impacts mitigation plan shall be provided to the Department along with the permit application. (7-135)	Yes (A6-5)	No	No	Applies to all wells, should be in regulations
Additional site-specific noise mitigation measures will be added to individual permits if a well pad is located within 1,000 feet of occupied structures or places of assembly. (7-135)	Partial(A6-5)	No	No	Permit applicants are required to identify mitigation measures in the noise mitigation plan, but there is no regulatory requirement that mitigation is included in permit conditions. Applies to all wells, should be in regulations
Modifying speed limits or restricting truck traffic on certain roads. (7-130)	No	No	No	
Noise modeling for any site within 1,000 feet of a noise receptor. (7-130)	No (noise mitigation plan is required, modeling is not mentioned)	No	No	The 1,000 feet distance is arbitrary and inconsistent with the 2011 RDSGEIS analysis results which show significant impacts out to 2,000+ feet from the well pad. Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Requiring the measurement of ambient noise levels prior to beginning operations. (7-130)	No	No	No	All of the following site specific measures are required "as practicable," but no procedure or criteria for determining practicability is specified.
Potential site-specific permit condition: Specifying daytime and nighttime noise level limits as a permit condition and periodic monitoring thereof. (7-130)	No	No	No	Daytime and nighttime noise limits should be established as part of the SGEIS and regulatory process, not on a permit by permit basis that does not allow for public review. The noise limits should be consistent and included in regulations.
Potential site-specific permit condition: Placing tanks, trailers, topsoil stockpiles, or hay bales between the noise sources and receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Using noise-reduction equipment such as hospital-grade mufflers, exhaust manifolds, or other high-grade baffling. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting drill pipe cleaning ("hammering") to certain hours .(7-131)	No	No	No	
Potential site-specific permit condition: Running of casing during certain hours to minimize noise from elevator operation. (7-131)	No	No	No	
Potential site-specific permit condition: Placing air relief lines and installing baffles or mufflers on lines. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting cementing operations to certain hours (i.e., perform noisier activities, when practicable, after 7 A.M. and before 7 P.M.). (7-131)	No	No	No	
Potential site-specific permit condition: Using higher or larger-diameter stacks for flare testing operations. (7-131)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Placing redundant permanent ignition devices at the terminus of the flow line to minimize noise events of flare re-ignition. (7-131)	No	No	No	
Potential site-specific permit condition: Providing advance notification of the drilling schedule to nearby receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Placing conditions on air rotary drilling discharge pipe noise, including: -orienting high-pressure discharge pipes away from noise receptors; - having the air connection blowdown manifolded into the flow line. This would provide the air with a larger-diameter aperture at the discharge point; - having a 2-inch connection air blowdown line connected to a larger-diameter line near the discharge point or manifolded into multiple 2-inch discharges; - shrouding the discharge point by sliding open-ended pieces of larger-diameter pipe over them; or -rerouting piping so that unusually large compressed air releases (such as connection blowdown on air drilling) would be routed into the larger-diameter pit flow line to muffle the noise of any release. (7-131)	No	No	No	
Potential site-specific permit condition: using rubber hammer covers on the sledges when clearing drill pipe. (7-131)	No	No	No	
Potential site-specific permit condition: Laying down pipe during daylight hours. (7-131)	No	No	No	
Potential site-specific permit condition: Scheduling drilling operations to avoid simultaneous effects of multiple rigs on common receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting hydraulic fracturing operations to a single well at a time. (7-131)	No	No	No	
Potential site-specific permit condition: Employing electric pumps. (7-131)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Installing temporary sound barriers (see Photo 7.2, Photo 7.3, and Photo 7.4) of appropriate heights, based on noise modeling, around the edge of the drilling location between a noise generating source and any sensitive surroundings. Sound control barriers should be tested by a third-party accredited laboratory to rate Sound Transmission Coefficient (STC) values for comparison to the lower-frequency drilling noise signature. (7-131)	No	No	No	

2.7 EAF and EAF Addendum

The EAF requires land use information for a distance of one-quarter (1/4) mile around the well pad. This distance is insufficient, as many impacts (including noise and visual) extend far beyond this distance. The EAF should require the identification and mapping of land uses within one mile of the well pad, as well as additional land use mapping along local roads that would be affected by heavy truck traffic (as identified in the required transportation plan) outside the one mile area. The EAF Addendum should specifically require the identification of land uses that are especially sensitive to noise, including protected open space, recreational areas, places of worship, campgrounds, hotels, schools, and healthcare facilities.

The details of the noise mitigation plan required by the EAF Addendum are not sufficiently defined to ensure impacts are mitigated. There is a need for a standardized noise impact assessment procedure and criteria for determining the reasonableness of various levels of mitigation expenditure (e.g., the cost per benefited receptor approach used by DOTs). Without standardized requirements for assessing and mitigating noise impacts, residents in areas affected by gas development will not receive fair or consistent treatment. The NYSDEC noise guidance document does not provide sufficient detail and criteria to ensure appropriate noise analyses conducted at the site level. At a minimum, NYSDEC should provide the detailed requirements of the noise mitigation plan, addressing the following components:

- Scope of study area for the mitigation plan (recommend one-half (1/2) mile around well pad plus sensitive areas adjacent to the local roads that would experience the largest percent increase in truck traffic).
- Methodology for establishing existing noise levels (recommend requiring 24-hour measurements at a few representative receptors).
- Required protocol for assessing noise impacts: what noise metrics should be used (Ldn, Lmax, peak hour Leq, percent time audible etc.); what sources need to be considered (transportation, drilling and fracking); acceptable software modeling packages; and sources of information on appropriate sound emission levels to assume for various types of the equipment.
- Required criteria for determining which impacts are significant and require mitigation and which do not.
- Required criteria for determining how much expenditure on mitigation is reasonable to address significant adverse impacts.

One template for NYSDEC to consider adopting to specify the requirements of noise impact analysis and mitigation plans is the Alberta Energy Resources Conservation Board (ERCB) Noise Control Directive (#38), which is described below in Section 2.8.

2.8 Best Practice Recommendation for Noise Standards and Site-Specific Impact Assessment Protocol

The Alberta ERCB Noise Control Directive was developed through an extensive scientific review process and is recognized as one of the most stringent in the world. The Noise Control directive is based on the calculation of a permissible sound level (PSL) at

the worst case receptor in terms of equivalent energy sound level (Leq)[9] for the daytime period and the nighttime period. The PSL calculation takes into account all the important factors that influence human annoyance due to noise:

- Daytime noise is allowed to be higher than nighttime noise, reflecting the greater sensitivity to noise occurring at night.
- Existing noise levels are taken into account based on dwelling unit densities and transportation infrastructure or through ambient monitoring.
- A sliding scale of adjustment factors based on the duration of the noise accounts for the fact that people are more tolerant of a brief period of noisy activity than a noise source that continues for months or years.

As a simple example, the PSL in a low density rural area not near a major transportation corridor would be calculated as follows for the drilling of one well (35 days):

Nighttime Drilling PSL= 40 dBA basic sound level + 5 dBA adjustment due to the duration
Nighttime Drilling PSL= 45 dBA

The daytime PSL for drilling in this simple example would be 10 dBA higher, or 55 dBA.

For five days of fracking, the PSL in a low density rural area not near a major transportation corridor would be calculated as follows:

Nighttime Fracking PSL= 40 dBA basic sound level + 10 dBA adjustment due to the duration
Nighttime Fracking PSL= 50 dBA

The daytime fracking PSL would be 10 dBA higher or 60 dBA. This daytime limit would be exceeded even at a distance of 2,000 feet from the well pad based on the RDSGEIS analysis without mitigation, which estimated 72 dBA at this distance, or approximately twice as loud as the standard.

The Alberta ERCB Noise Control Directive also outlines detailed requirements to standardize the modeling of noise impacts and the preparation and documentation of noise studies that would be appropriate for NYSDEC to consider in regulating noise from HVHF in New York.

3.0 Ground-Borne Vibration and Noise

Page 6-251 of the RDSGEIS acknowledges the potential for ground-borne vibration impacts in the discussion of potential effects on property values: “Gas well development could impact local environmental resources and cause noise and vibration impacts, and trucks servicing the well development could also impact the surrounding areas.” Despite this statement, no vibration impact analysis (or an explanation of why an analysis was not conducted) is presented in the 2011 RDSGEIS. NYSDEC should analyze vibration impacts addressing the following issues:

[9] Leq refers to the constant sound level that conveys the same energy as the variable sound levels during the analysis period.

- Construction-period vibration impacts for access road and well pad development. Recommended procedures are provided in Section 12.2 of the Federal Transit Administration's *Transit Noise and Vibration Impact Assessment* guidebook. A simple qualitative assessment may be appropriate in this case. While construction activities do not typically create vibration levels capable of damaging most buildings, fragile historic buildings are more sensitive and should be avoided in the siting of access roads and well pads. Ground vibration from construction can also be an annoyance to adjacent land uses.

- Operation vibration impacts associated with drilling and fracking. This assessment should include information on drilling vibration levels from existing natural gas development in New York and other locations. While it is difficult to generalize vibration effects from one area to another due to the effects of local soils and geologic conditions, this information would provide a rational basis for identifying a screening distance for determining when a more detailed vibration impact assessment should be required at the site level. If no receptors are within the screening distance at which perceptible vibration levels could occur, then no vibration assessment would be required in the site level review.

- Operation low-frequency ground-borne noise impacts. Ground vibration can create a phenomenon known as ground-borne noise, a rumble associated with the movement of the interior surfaces of a room.[10] Special considerations apply when assessing low-frequency noise because of the non-linearity of human hearing which causes sounds dominated by low-frequency components to seem louder than broadband sounds that have the same A-weighted level. As a result, even low levels of low-frequency noise (generally defined as the frequency range below 200 Hz) can be perceived as highly annoying and contribute to sleep problems and other health problems caused by sleep disruption. In addition to sleep disturbance and physiological stress, there is strong evidence that noise exposure can contribute to cardiovascular diseases.[11] NYSDEC should assess the potential for the various phases of well development and production to generate ground-borne noise, including any on-site equipment such as condensers that have been anecdotally reported generating high vibration levels in Pennsylvania.

Based on the ground-borne noise and vibration impact assessment conclusions, the NYSDEC should identify ground-borne noise and vibration impact mitigation measures and ensure that information necessary to identify and mitigate ground-borne noise and vibration impacts at the site level is required as part of the EAF Addendum, supplemental permit conditions and/or regulations.

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[10]Both ground-borne noise and vibration are issues associated with the inside of buildings and are generally not annoying outdoors.

[11] See Cardiovascular effects of noise. Noise Health. Vol. 15 Issue 52. http://www.noiseandhealth.org/showBackIssue.asp?issn=1463-1741;year=2011;volume=13;issue=52;month=May-June

4.0 Visual

4.1 Impact Assessment

The RDSGEIS describes in very broad terms the potential direct and cumulative impacts of various phases of natural gas development on NYSDEC-designated visually sensitive resources. The RDSGEIS considers and incorporates information from two studies by others that addressed the visual impact of high-volume hydraulic fracturing.[12] The public disclosure of significant adverse visual resource impacts should be improved by providing the following:

- Discussion of the various viewer groups (local residents, through travelers, tourists, etc.) that would experience changed views as a result of natural gas development and their relative sensitivity. For example, local residents are familiar with local views and may be very sensitive to changes in views they consider important. Tourists visiting an area in part to experience high visual environment quality would also be much more sensitive than general through travelers that would have passing views of natural gas development from roadways while commuting. NYSDEC should describe how natural gas development at the scale anticipated in the socioeconomic impact study would affect viewer perceptions.

- To aid in the identification and understanding of impacts, landscape similarity zones (rural open areas, rural wooded areas, villages, cities, etc.) should be identified statewide and computer modeling conducted to create three dimensional photo simulations of various phases of the well development process at various distances for each zone. NYSDEC would not need to develop this analysis from scratch—significant consultant costs could be saved by using the New York State Office For Technology's "Generic Visual Impact Assessment" prepared for the 2004 Statewide Wireless Network (SWN) DGEIS as a starting point.[13] The SWN Generic Visual Impact Assessment is an excellent example for NYSDEC to follow in comprehensively addressing visual impacts at the GEIS stage. The landscape similarity zones and representative photos selected for photo simulations used in the SWN analysis could likely be used with no to little modification. The main additional work required would be to define the components of a typical well pad development at various phases in sufficient detail and re-run the simulation model.

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[12]Upadhyay and Bu. 2010. Visual Impacts of Natural Gas Drilling in the Marcellus Shale Region. Cornell University, Dept. of City and Regional Planning: CRP 3072 Land Use, Environmental Planning, and Urban Design Workshop

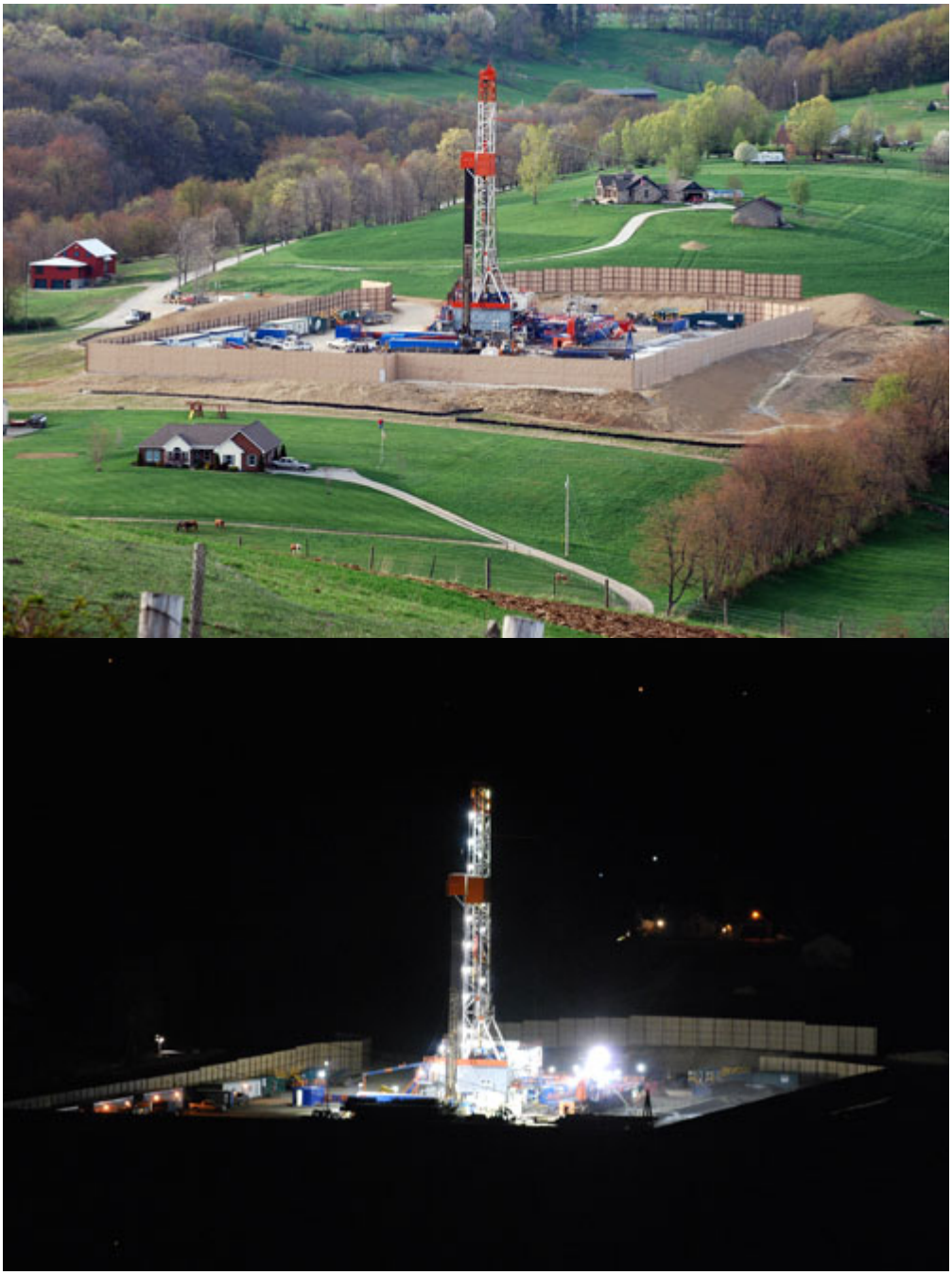
Rumbach, Andrew. 2011. Natural Gas Drilling in the Marcellus Shale: Potential Impacts on the Tourism Economy of the Southern Tier

[13]New York State Office for Technology. 2004. *Draft Generic Environmental Impact Statement for the New York State Statewide Wireless Network*. Cultural Resources Appendix B. Prepared by Environmental Design & Research, P.C. (now EDR Companies)

- Analysis of light pollution impacts of nighttime lighting and flaring. The RDSGEIS analysis focuses on daytime visual impacts and downplays nighttime light impacts as a "temporary impact" that most of the viewing public would not be exposed to (see page 6-281). Light pollution impacts would not be temporary when the duration of drilling, fracturing and production activities is considered for multi-well pads and cumulatively as numerous well pads are added throughout the region over the 60 year development timeframe contemplated in the RDSGEIS. The RDSGEIS ignores the visual impact to local residences that comes with the loss of pristine dark nighttime skies in rural areas. Residences are not even mentioned in the impact assessment. In many cases the nighttime impact will be more significant than the daytime visual impact because the lighting will make the well site a pronounced focal point. In addition to evaluating the visual impact of light pollution on humans, NYSDEC also needs to evaluate the impact of nighttime lighting and flaring on migratory birds.[14]

The photographs of a PA well site below illustrate the dramatic visual impact of natural gas development in a rural residential setting during the day and night.

[14] Poot, H., B. J. Ens, H. de Vries, M. A. H. Donners, M. R. Wernand, and J. M. Marquenie. 2008. Green light for nocturnally migrating birds. *Ecology and Society* **13**(2): 47. http://www.ecologyandsociety.org/vol13/iss2/art47/
For background information on light pollution impacts on wildlife see: http://www.darksky.org/index.php?option=com_content&view=article&id=719



Day and Night Views of Chappel Unit 1H-10H in Hopewell Township, Washington County PA. Source: http://www.marcellus-shale.us/Chappel-Unit.htm

4.2 Mitigation

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would only be considered when designated significant visual resources (parks, historic resources, scenic rivers, etc.) are present and within the viewshed of proposed wells. This approach fails to consider visual impacts on nearby residences or tourists in areas where a significant visual resource is not present. In these situations, no mitigation would be required for individual wells to be consistent with the RDSGEIS. NYSDEC should make basic and low-cost mitigation measures mandatory for all well development sites (such as keeping lighting levels at the minimum level required and directing lights downward to minimize light pollution), regardless of whether or not significant visual resources are present. In addition, a broader menu of more sophisticated and costly mitigation measures should be provided for those development sites that do have the potential to impact designated visual resources.

Table 3 summarizes the visual impact mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum, regulations or supplemental permit conditions. The mitigation measures not included in the EAF, regulations or permit conditions are not enforceable. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A); therefore it would be reasonable and consistent to also include many of the visual impact mitigation measures in Table 3 as supplemental permit conditions. A few of the visual impact mitigation measures that are general enough and are applicable to all well sites should be incorporated into the proposed regulations. These mitigation measures are identified in the notes column of Table 3.

Table 3
Visual Impacts Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Prepare visual impacts mitigation plan (A6-6 and Supplemental Permit Conditions).	**Yes**	No	**Yes**	Applies to all wells, should be in regulations
Flaring would only occur during initial flowback at some wells, and the potential for flaring would be limited to the extent practicable by permit conditions, such that the duration of nighttime impacts from flaring typically would not occur for longer than three days. (6-281)	No	No	No	Applies to all wells, should be in regulations
The development of measures to reduce impacts on visual resources or visually sensitive areas would follow the procedures identified in NYSDEC DEP-00-2, "Assessing and Mitigating Visual Impacts." (7-121)	No	No	No	Applies to all wells, should be in regulations
Design and siting measures, as described in NYSDEC DEP-00-2, would typically consist of screening, relocation, camouflage or disguise, maintaining low facility profiles, downsizing the scale of a project, using alternative technologies, using non-reflective materials, and controlling off-site migration of lighting (NYSDEC 2000). (7-122)	No	No	No	Design and siting mitigation measures would be primarily site specific, but some measures could be incorporated in regulations (see the mitigation measure below regarding avoiding ridgelines and minimizing light pollution).
Relocating well sites to avoid ridgelines or other areas where aboveground equipment and facilities breaks (sic) the skyline; and minimizing off-site light migration by using night lighting only when necessary and using the minimum amount of nighttime lighting necessary, directing lighting downward instead of horizontally, and using light fixtures that control light to minimize glare, light trespass (off-site light migration), and light pollution (sky glow). (7-125)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
The study also recommends the development of a best practices manual for Department staff and the industry, which would provide information on what is expected by the Department in terms of well siting and visual mitigation, and the identification of instances where visual mitigation may be necessary. (7-126)	No	No	No	
Develop a feedback mechanism in the project review process to confirm the success of measures to avoid, minimize, or mitigate visual impacts, based on the analysis of results for prior projects. (7-126)	No	No	No	
The maintenance activities described in NYSDEC DEP-00-2 should be implemented to prevent project facilities from becoming “eyesores.” Such measures would typically consist of appropriate mowing or other measures to control undesirable vegetation growth; erosion control measures to prevent migration of dust and/or water runoff from a site; measures to control the off-site migration of refuse; and measures to maintain facilities in good repair and as organized and clean as possible according to the type of project. (7-126)	No	Partial- mostly related to stormwater and erosion control	Partial- SWPPP required	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
The decommissioning activities described in NYSDEC DEP-00-2 should be implemented when the useful life of the project facilities is over; these activities would typically occur during the reclamation phase for well sites. Such activities would typically consist of, at a minimum, the removal of aboveground structures at well sites. Additional decommissioning activities that may also be required include: the total removal of all facility components at a well site (aboveground and underground) and restoration of a well site to an acceptable condition, usually with attendant vegetation and possibly including recontouring to reestablish the original topographic contours; the partial removal of facility components, such as the removal or other elimination of structures or features that produce visual impacts (such as the restoration of water impoundment sites to original conditions); and the implementation of actions to maintain an abandoned facility and site in acceptable condition to prevent the well site from developing into an eyesore, or prevent site and structural deterioration. (7-127)	Partial- site reclamation plans required, but no specific measures are required.	Partial (560.7 Reclamation)	Partial (reclamation plans required)	
The offsetting mitigation described in NYSDEC DEP-00-2 should be implemented when the impacts of well sites on visual resources or visually sensitive areas are significant and when such impacts cannot be avoided by locating the well pad in an alternate location. Per guidance in NYSDEC DEP-00-2, offsetting mitigation would consist of the correction of an existing aesthetic problem identified within the viewshed of a proposed well project. (7-128)	No	No	No	

4.3 EAF and EAF Addendum

There are a number of problems with the EAF and EAF Addendum requirements as currently drafted that will result in significant unmitigated adverse visual impacts if not corrected.

The EAF does not require sufficient information to properly identify receptors that would experience views of proposed wells. The EAF requirement is to identify the distance to the closest occupied building or outdoor facility. The EAF Addendum requires identification of "[a]ll residences, occupied structures or places of assembly within 1,320 feet." This is not a sufficient distance for assessing visual impacts and does not take into account the fact that the closest structures may not be the most impacted depending on local vegetation and topography patterns.[15] A more reasonable distance for identifying sensitive resources and receptors in most instances would be one mile.[16] The EAF addendum should require a visibility analysis to determine where the well site facilities would be visible from public roadways, parks, residences and other sensitive receptors. The number of viewers exposed and the activities viewers would typically be engaged in during exposure needs to be evaluated to determine the extent of visual impacts and the need for mitigation at the site level. NYSDEC has developed excellent guidance on this topic ("Assessing and Mitigating Visual Impacts") and a useful visual EAF addendum. These best practice approaches to visual impact assessment and mitigation should be required as part of the EAF for proposed well development sites.

Unlike the noise and traffic mitigation plans, a visual impacts mitigation plan is not a required component of the submittals to NYSDEC with the permit application, EAF and EAF Addendum. The visual impacts mitigation plan does not even have to be prepared prior to issuance of the well drilling permit and is not subject to prior approval by NYSDEC. The only apparent requirement is that the visual resource mitigation plan is prepared by the applicant in conformity with the SGEIS and made available to the NYSDEC on request. This procedure offers no opportunity for public review or even notice to affected local residents. A visual resources mitigation plan that is not subject to public review and that does not require NYSDEC approval is not an adequate mitigation measure.

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[15]The RDSGEIS acknowledges that on-site equipment would be a prominent landscape feature at distances of up to double 1,320 feet used in the EAF Addendum. Page 6-274: "On-site equipment would be the most visible sign of fracturing activity and, when viewed from relatively short distances (i.e., from 1,000 feet to 0.5 miles) are relatively prominent landscape features."

[16] Although drilling activity during the daytime would be most prominent within ½ mile, a one mile distance is reasonable to account for areas with topography that could make well sites prominent features for more distant views and to address nighttime lighting impacts (which could be prominent at greater distances than the physical appearance of the well site equipment during the day.

5.0 Land Use

5.1 Impact Assessment

The RDSGEIS fails to provide any analysis of the reasonable foreseeable cumulative land use impacts that would result if high-volume hydraulic fracturing was permitted in New York. To comply with SEQRA, NYSDEC should provide the following information:

- An overview of statewide existing land uses patterns and land use planning framework. Much of this information and mapping could be adopted directly from Section 3.3.2.2 of the 2004 Statewide Wireless Network DGEIS and associated appendices. This would provide an appropriate baseline to use in assessing potential land use impacts.

- A quantitative analysis of potential land cover change at the county level. This analysis could use readily available GIS land cover data for existing conditions and assume that well development would impact land cover proportionate to the existing percentage of land cover types in each county (excluding water and developed land). Impacts could be assessed using the average 7.4 acres of disturbance per multi-well pad used in the RDSGEIS (page 5-6) and an estimate of the number of well pads by county consistent with the economic impact study county-level estimates. Cumulative impacts associated with existing trends and known major development proposals should be evaluated, taking into account the lack of capacity of rigorous land use regulation throughout most rural areas of the Southern Tier.

- A qualitative assessment of the compatibility of natural gas development with various adjacent land uses, taking into consideration impacts associated with truck traffic, noise and visual impacts. Appropriate buffer zones should be recommended between natural gas development and incompatible land uses such as residences, parks and schools to minimize impacts.

- A qualitative assessment of the consistency of natural gas development with local and regional plans. Specific land use plans and zoning regulations could not be analyzed in detail in a GEIS, but generalized planning areas common to many areas of the Marcellus shale region could be considered (e.g., rural residential, agricultural, commercial, etc.). Natural gas development should not be permitted to undermine local land use laws, especially planning in rural areas that emphasizes resource protection, open space, and scenic quality. Potential inconsistencies with plans prepared pursuant to New York's Local Waterfront Revitalization Program should be specifically considered in this assessment.

The failure of the RDSGEIS to analyze land use impacts is inconsistent with the scope for the SGEIS, which included a commitment to conduct an "[e]valuation of whether any aspect of multi-well site development or high-volume hydraulic fracturing of shale wells could be expected to change the GEIS's conclusion that major long-term changes to land use patterns, traffic and the need for public services are not anticipated as the result of gas well development. This will include review of the compatibility of shale gas development with other land uses such as agriculture, tourism, and alternative energy

development."[17] The RDSGEIS is deficient because it does not contain a land use impact assessment addressing compatibility with agriculture, tourism, and alternative energy development.

5.2 Mitigation

The RDSGEIS fails to provide any discussion of mitigation measures for land use impacts. Based on the additional analyses of land use impacts recommended above, mitigation measures such as buffer distances for incompatible land uses should be described and incorporated into enforceable regulations or supplemental permit conditions, as appropriate. The RDSGEIS should make it clear that such mitigation measures are intended to supplement any local zoning or other land use planning addressing the location of industrial uses, including gas development.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate land use impacts at HVHF sites, and use this information to refine the land use mitigation requirements for future permit applications.

5.3 EAF and EAF Addendum

The topic of consistency with local plans was not addressed in the EAF and EAF Addendum in the 2009 DSGEIS. The addition of a requirement related to the review of local plans and assessment of consistency as part of the EAF Addendum in the RDSGEIS is an improvement. The term "land use plan" should be broadly defined in the EAF Addendum to ensure it encompasses comprehensive plans, zoning ordinances, subdivision regulations, site plan review requirements, hazard mitigation plans, open space plans, agricultural/farmland protection plans, Local Waterfront Revitalization Program plans, historic districts/historic resource protection plans, economic revitalization and tourism plans, ecological and water resource protection/restoration plans etc.

With respect to the avoidance of land use compatibility impacts, the requirements of the EAF Addendum in the RDSGEIS remain extremely vague. Permit applicants are required to attest that "[u]nless otherwise required by private lease agreement, the access road will be located as far as practical from occupied structures, places of assembly and unleased property." There are no definitional or other criteria for determining what is "as far as practical" concerning location of the access road in relation to occupied structures, places of assembly and unleased property. Nor is there any required explanation by the applicant to support its affirmation or submission of a map showing such structures and uses in relation to the access road. Nor is there any required hierarchy in determining which uses of land require greatest distance from the access road in the event that movement of the access road away from one use would bring it closer to another. All that is required of the applicant is a bare affirmation that it has located the access road.

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[17] NYSDEC. 2009. *Scope for the 2009 Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program*. Page 41

The EAF Addendum requires the identification of "[a]ll residences, occupied structures or places of assembly within 1,320 feet." However, as noted previously, there is evidence that significant impacts (such as noise) extend beyond 1,320 feet. In order to comply with SEQRA, NYSDEC must require that the applicant identify all land uses within one mile of a proposed well. These land uses should include, but not be limited to hospitals, senior citizen residences, schools, places of worship, and residential uses.

6.0 Transportation

6.1 Impact Assessment

Additional analysis is provided in the RDSGEIS regarding truck trip generation (e.g., the number of truck trips to and from the well site at varies stages), but the impact on roadway congestion and safety has not been adequately addressed. The impacts of a typical multi-well development on congestion and safety should be analyzed in detail, as well as a cumulative traffic effects analysis using a reasonable worst case development scenario. The reasonable worst case development scenario for regional traffic impacts should include indirect traffic generation associated with increased economic development and population growth attributable to natural gas extraction and related industries. Finally, the statewide impact on vehicle miles traveled (VMT) should be reported, taking into account the long distance truck trips that would be required to haul produced water and brine waste out of state for disposal.

6.1.1 Traffic Congestion and Safety Impacts of a Typical Multi-Well Pad

The detailed analysis of the traffic congestion and safety impacts of one typical multi-well pad development serves an important purpose in terms of disclosing the general types of impacts that could occur in many similar locations, but also in terms of creating an analysis template for permit applicants to follow in developing their transportation plans for specific development proposals. A hypothetical well site could be identified in the area where the greatest drilling is expected (Region A) or an actual well site in an area of Pennsylvania representative of similar areas in New York could be analyzed. Once the hypothetical or actual well site is located, the following tasks should be undertaken:

- Identification of the project area where transportation impacts would be most likely based on actual or hypothetical information on trip origins and routes for workers, equipment and water deliveries to the site.
- Characterization of existing conditions in the project area using NYSDOT traffic counts, local data and additional traffic counts as needed. Topics to be addressed should include traffic volumes, intersection level of service, crash rates, etc.
- Analysis of impacts on traffic volumes, intersection congestion and safety consistent with the 2010 Highway Capacity Manual, NYSDOT procedures for traffic impact assessment and good transportation engineering practice.
- Development of mitigation measures to address significant impacts, such as changes in signal timing, temporary traffic signals, limitations on the routes used by water trucks, etc.

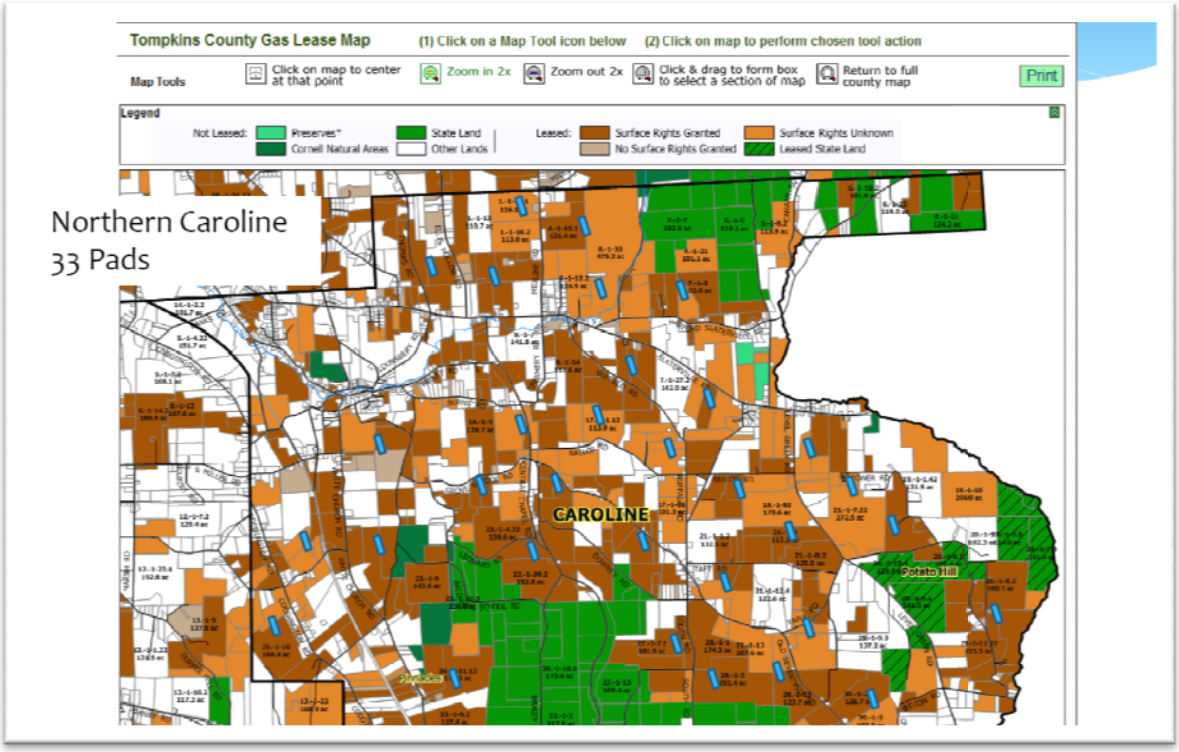
6.1.2 Regional Traffic Congestion and Safety Impacts

In addition to analyzing one well site in detail, it is important for NYSDEC to analyze regional cumulative impacts because these types of impacts will not likely be considered at the site level in the review of individual permits. The regional analysis would consider changes in traffic volumes on major roadways and the resulting potential for increased congestion and crashes from the combined effects of truck traffic to individual wells, as well as traffic related to additional employment and population growth. One methodology for conducting a meaningful regional analysis would be to use an existing travel demand model within the Marcellus and Utica shale regions. Unfortunately, neither New York State nor the Metropolitan Planning Organizations (MPOs) in Region A have a statewide or regional travel demand model. However, there are still several possible options for NYSDEC to conduct a meaningful regional scale transportation modeling analysis.

One option would be to use an analysis of Tompkins County as a surrogate for similar regional scale impacts that could occur in other places. There are several advantages to this approach:

- The Ithaca-Tompkins County Transportation Council (ITCTC) has an existing travel demand model that covers all of Tompkins County.

- The Tompkins County Council of Governments Task Force on Gas Drilling has identified realistic scenario of potential well locations for Tompkins County based on a GIS analysis and information from the 2009 DSGEIS.[18] An example map output from this analysis is provided in the figure below.



[18] http://www.tompkins-co.org/tccog/Gas_Drilling/Focus_Groups/Mapping.html

Example of Well Pad Placement Assessment for the northern portion of the Town of Caroline, Tompkins County. Source: http://www.tompkins-co.org/tccog/Gas_Drilling/Focus_Groups/Mapping%20Minutes/Section%203%20-%20TC%20Mapping%20Analysis.pdf

The travel demand model could be run for multiple scenarios but, at a minimum, future no action and action (peak year of traffic generation) scenarios should be run. Key considerations in setting up the model should include identifying the traffic analysis zones that would experience increased population and employment and appropriately defining the trips attracted to well sites and other important destinations, such as hypothetical water source areas and waste disposal areas. These parameters could easily be established by a team composed of a travel demand modeling expert and a person familiar with hydraulic fracturing well site development stages and trucking needs (making the assumptions available for public review). A cooperative study in partnership with the ITCTC could be particularly beneficial to take advantage of their familiarity with local conditions and the existing model.

Once the model runs are complete, the results should be post-processed and used to develop an informative impact analysis and mapping (e.g., link volume change maps, volume/capacity ratio maps, etc.). This type of regional analysis is routinely conducted by MPOs as part of the long-range transportation planning process. There are numerous examples and guidance sources available to NYSDEC on how to conduct regional transportation analyses for planning that are equally applicable to generic regional traffic impact analysis.[19]

6.1.3 Statewide Vehicle Miles Traveled Impact

Vehicle miles traveled (VMT) is a key indicator used in transportation planning to compare various future scenarios and investment decisions. Increases in heavy truck VMT provide a basis for drawing general conclusions about the effects of HVHF on the transportation system, as well as effects on air pollutant emissions from mobile sources. While information on the number of trips is discussed in the transportation impacts section of the RDSGEIS, VMT impacts are not addressed. The failure of the transportation section to address VMT impacts is especially problematic because statewide VMT estimates were developed for the air quality analyses in the RDSGEIS (see page 6-176). As discussed in further detail below, the RDSGEIS VMT estimates for air quality should be revised to take into account out-of-state waste disposal and incorporated into the transportation impact assessment section, as well as the air quality section.

As discussed in Glenn Miller's accompanying technical memorandum, the waste disposal requirements for produced water and brines cannot be met at any existing disposal facilities in New York. This means that a significant number of long-distance heavy truck trips would be needed to move wastes out of state for disposal. VMT information for the RDSGEIS air quality analyses was generated using average truck trip

[19]See: NCHRP Report 546: Incorporating Safety into Long-Range Transportation Planning.

FHWA. 2003. "Tools for Assessing Safety Impacts of Long-Range Transportation Plans in Urban Areas."

length information provided by the industry.[20] The industry data was from Bradford County, PA. The data collection methodology and the number of well sites upon which the industry average truck trip length estimates were developed were not disclosed in the RDSGEIS or the industry memo providing the estimates to NYSDEC. Industry estimated 100 truck trips for produced water disposal from each horizontal well, with each waste disposal truck traveling an average distance of 24 miles (one-way).[21] While supporting calculations are not provided to ascertain how the distance of 24 miles was computed, it would appear that the industry's data set was weighted heavily towards well sites where produced brine was reused at other nearby wells. This does not take into account the final disposal transportation impacts. A review of Pennsylvania Department of Environmental Protection (PADEP) waste reports[22] for Bradford County show two primary final disposal sites for brines from wells in the county:

- Pennsylvania Brine and Treatment, Inc. in Franklin, PA (approximately 200 miles from Bradford County municipalities such as Troy).
- Waste-Treatment Corporation in Warren, PA (approximately 140 miles from Bradford County municipalities such as Troy).

The 24-mile trip average distance for waste disposal provided by industry does not reflect the long distance waste hauling that occurs in Bradford County and would be expected to occur in New York. To correct this deficiency, NYSDEC should independently reevaluate the average trip length information provided by industry and develop revised truck trip length estimates that take into account final waste disposal transportation impacts. The assumptions used in generating the average truck trip length estimates should be disclosed for public review. This will allow for a more realistic assessment of the potential transportation and air quality impacts that will result from the statewide increase in VMT.

6.2 Mitigation

The majority of the transportation mitigation discussion in the RDSGEIS is focused on damage to roadways and road use agreements. While this remains an important issue, the RDSGEIS does not give sufficient attention to traffic impact mitigation measures. A list of generic mitigation measures for traffic impacts is provided (Section 7.11.3), but it is not clear when specific mitigation measures would be required because no impact criteria have been defined. For example, at what level of predicted intersection level of service would mitigation have to be considered? NYSDEC should make clear what traffic impact criteria would trigger the need for mitigation measures and include a process for local government and public review of the transportation plans for proposed well sites before NYSDEC issues a permit.

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[20] March 16, 2011 Letter from ALL Consulting to IOGA New York, obtained through a FOIL request. The footnote referencing this letter (footnote #100) was missing from the RDSGEIS.

[21] See Exhibit 19A in the March 16, 2011 ALL Consulting letter

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[22] Pennsylvania Oil and Gas Well Statewide Waste Report by Reporting Period. Jan - Jun 2011 (Marcellus Only, 6 months)
https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx

Table 4 summarizes the transportation mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum, regulations or supplemental permit conditions. The mitigation measures not included in the EAF, regulations or permit conditions are not enforceable. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A); therefore it would be reasonable and consistent to also include many of the transportation mitigation measures in Table 4 as supplemental permit conditions. Other mitigation measures are general enough to apply to all well sites and should be incorporated into regulations as described in the “notes” column of Table 4.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate transportation impacts of HVHF, and use this information to refine the transportation mitigation requirements for future permit applications.

Table 4
Transportation Impacts Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Development of Transportation Plans, Baseline Surveys, and Traffic Studies. (7-136)	Yes	Yes (560.3)	Yes- transportation plan must be approved by NYSDEC and is "incorporated by reference" into the permit	The details of the transportation plan related-requirements should be described in greater detail in the EAF Addendum, along with an example transportation plan to provide clear guidance to industry on the level of data collection and analysis NYSDEC and NYSDOT expect.
Municipal Control over Local Road Systems. (7-137)	N/A	N/A	N/A	This is a mitigation measure that cannot be implemented by NYSDEC- it relies on municipalities with very limited planning resources to be proactive in protecting their roads.
The owner or operator should attempt to obtain a road use agreement with the appropriate local municipality; if such an agreement cannot be reached, the reason(s) for not obtaining one must be documented in the Transportation Plan. The owner or operator would also have to demonstrate that, despite the absence of such agreement, the traffic associated with the activity can be conducted safely and that the owner or operator would reduce the impacts from truck traffic on local road systems to the maximum extent feasible. (7-138)	Partial- copy of road use plan must be submitted if there is one.	No	Partial- copy of road use plan must be submitted if there is one.	Applies to all wells, should be in regulations
Route selection to maximize efficient driving and public safety, pursuant to city or town laws or ordinances as may have been enacted under Vehicle and Traffic Law §1640(a)(10). (7-138)	No	No	No	Applies to all wells, should be in regulations
Avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods, as established by Vehicle and Traffic Law §1640(a)(20). (7-139)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Coordination with local emergency management agencies and highway departments. (7-139)	No	No	No	Applies to all wells, should be in regulations
Upgrades and improvements to roads that will be traveled frequently for water transport to and from many different well sites, as may be reimbursable pursuant to ECL §23-0303(3). (7-139)	No	No	No	Refers to provision of ECL that allows municipalities to request from NYSDEC "funds from the oil and gas fund to reimburse the municipality for costs incurred in repairing damages to municipal land or property. Such requests shall include such explanatory material and documentation as the commissioner may require."
Advance public notice of any necessary detours or road/lane closures. (7-139)	No	No	No	Applies to all wells, should be in regulations
Adequate off-road parking and delivery areas at the site to avoid lane/road blockage.(7-139)	No	No	No	Provision of large parking and delivery areas may increase the footprint of the well development sites, increasing ecological and water quality impacts.
Use of rail or temporary pipelines where feasible to move water to and from well sites. (7-139)	No	No	No	
Prior to site disturbance, the operator shall submit to the Department and provide a copy to the NYSDOT of any road use agreement between the operator and local municipality. (7-139)	Yes	No	Yes	Applies to all wells, should be in regulations
The operator shall file a transportation plan, which shall be incorporated by reference into the permit; the plan will be developed by a NYS-licensed Professional Engineer in consultation with the Department and will verify the existing condition and adequacy of roads, culverts, and bridges to be used locally. (7-139)	Yes	Yes	Yes	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Mitigating Incremental Damage to the State System of Roads. (7-141)	N/A	N/A	N/A	Damage to the state road system is identified in the RDSGEIS as an unmitigated impact. The Final SGEIS and HVHF regulations should include a transportation fee on permit applications to compensate for the costs of repairing HVHF-related damage to the state road system.
Limiting truck weight, axle loading, and weight during seasons when roads are most sensitive to damage from trucking (e.g., during periods of frost heaving and high runoff). (7-141)	No	No	No	
Requiring the operator to pay for the addition of traffic control devices or trained traffic control agents at peak times at identified problem intersections or road segments. (7-141)	No	No	No	
Providing industry-specific training to first responders to prepare for potential accidents. (7-141)	No	No	No	
Road use agreements limiting heavy truck traffic to off-hour periods, to the extent feasible, to minimize congestion. (7-141)	No	No	No	
Providing a safety and operational review of the proposed routes, which may include commitments to providing changes to geometry, signage, and signaling to mitigate safety risks or operational delays. (7-141)	No	No	No	
Avoiding hours and routes used by school buses. (7-141)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
1.0 Where appropriate the Department would impose specific construction windows within well construction permits in order to ensure that drilling activity and its cumulative adverse socioeconomic effects are not unduly concentrated in a specific geographic area. Those 2.0 measures, designed to mitigate socioeconomic impacts and impacts on community character, can also be employed to minimize operational and safety impacts where such impacts are identified. (7-142)	No	No	No	The effectiveness of this measure is difficult to assess because the RDSGEIS does not explain what criteria would trigger a limitation on well permits within a specific area. Applying an adaptive management approach is logical, but it requires substantial resources and planning to monitor well development pressures at the local level. NYSDEC has not explained how such a monitoring system would be implemented, and thus this mitigation measure is likely to be ignored or forgotten once NYSDEC starts issuing permits.
Reducing trucking through different technology, such as on-site treatment. (7-142)	No	No	No	
The operator will provide specific information on the types and quantities of hazardous materials expected to be transported through the jurisdictions that they will be operating in and brought on site as part of the permitting process. (7-142)	Yes	Yes (560.3)	Yes	
All fracturing fluids and additives are transported in “DOT-approved” trucks or containers. (7-142)	N/A	N/A	N/A	This measure cannot be enforced by NYSDEC- depending on federal or NYSDOT oversight of hazardous material movement.
First responders and emergency personnel would need to be aware of hazardous materials being transported in their jurisdiction and also be properly trained in case of an emergency involving these materials. Permit conditions may require the operator to provide first responder emergency response training specific to the hazardous materials to be used in the drilling process if a review of existing resources indicates such a need. (7-143)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Transportation plans may provide that sensitive locations be avoided for trucks carrying hazardous materials. (7-143)	No	No	No	To make this mitigation measure meaningful, it would be helpful for NYSDEC to identify the specific categories of sensitive facilities that permit applicants must identify and avoid in developing trucking routes (bridges over drinking water supply reservoirs for example).

6.3 EAF and EAF Addendum

A transportation plan is a required component of the EAF Addendum. The scope of the transportation plan is discussed in RDSGEIS Section 7.11.1.1 and includes "the number of anticipated truck trips to be generated by the proposed activity; the times of day when trucks are proposed to be operating; the proposed routes for such truck trips; the locations of, and access to and from, appropriate parking/staging areas; and the ability of the roadways located on such routes to accommodate such truck traffic." NYSDEC should provide details on the scope of the specific analyses that should be performed for the transportation plan to ensure a uniform approach is used.

7.0 Community Character

7.1 Impact Assessment

Community character is an amalgam of various elements that give communities their distinct "personality." These elements include a community's land use, architecture, visual resources, historic resources, socioeconomics, traffic, and noise (CEQR Tech. Manual). The community character impact assessment portion of the RDSGEIS lists some of the community character impacts that could be expected (focused on demographic and economic impacts), but does not analyze the significance of these impacts or draw conclusions on how proposed new natural gas development in the Marcellus and Utica shales would affect community character in the short-term and long-term. The impact assessment does not mention the contribution of visual, land use or historic resource impacts to community character. The discussion of traffic and noise impacts is superficial (two sentences each).

The community character impact assessment in the RDSGEIS appears to be based on the *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in Marcellus Shale and Other Low-Permeability Gas Reservoirs* report prepared by NTC Consultants for NYSERDA. To the extent the analysis in the RDSGEIS derives from or relies upon this report, it is significantly flawed in that for the most part it considers a few of the elements of community character individually (visual, noise, traffic), without drawing conclusions on the cumulative impact of all the changes associated with the expected level of new development. Much of the cumulative impact discussion in the report focuses on attempting to explain why a regional cumulative impact assessment based on a reasonable worst case development scenario is not necessary or helpful. The report also states:

> "The approach for addressing regional cumulative impacts is to focus on the proactive siting of well pads as discussed in previous sections of this report. If the location and construction of each well pad is based on 'Best Practices' (See Appendix A) then the potential impacts will be lessened and/or eliminated. **When applications are reviewed, it is recommended that DEC examine any negative issues that have occurred on adjacent well pads to determine if there is a potential problem in the area that needs further scrutiny**." Page 38. Emphasis added.

The suggested approach is to let the impacts occur and then do something about those impacts if there is a problem. NYSDEC adopted this approach in the form of the vague mitigation commitment to monitor the pace of well development and respond through limits on permits in specific areas to minimize cumulative socioeconomic impacts (see page 7-120). This is contrary to SEQRA, the intent and spirit of which is to consider impacts *before* making a decision to approve the proposed action. NYSDEC must address regional cumulative community character impacts and not defer the issue to the future after the impacts have occurred. An adaptive management framework to addressing HVHF impacts is useful (as discussed further below), but this does not excuse the omission of a complete community character impact assessment in the RDSGEIS.

7.2 Mitigation

The community character mitigation section of the RDSGEIS focuses on the EAF Addendum requirement related to consistency with local plans. There is also a mitigation commitment requiring site-specific review and additional mitigation measures of disturbance of 2.5 acres or more within an agricultural district. However, the agricultural district mitigation commitment is not enforceable because it is not included in the EAF Addendum, regulations or supplemental permit conditions.

The community character mitigation section also references the visual, noise, transportation and socioeconomic mitigation commitments in Chapter 7. However, as noted in the other sections of this review, enforceable mitigation has not been provided for those topics, which means that the unmitigated impacts in those subject areas will contribute to unmitigated community character impacts.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate community impacts of HVHF, and use this information to refine the community impacts mitigation requirements for future permit applications. NYSDEC contemplates such a similar approach in the discussion of mitigation for socioeconomic impacts (page 7-120), but the details of how this monitoring system would work need to be defined and circulated for public review and comment.

7.3 EAF and EAF Addendum

Community character impacts are not addressed as a distinct topic in the EAF or EAF Addendum.

8.0 Cultural Resources

8.1 Impact Assessment

Cultural resources, also referred to as historic properties, link a community with its past. These are finite resources and are provided protections through local, state, and federal authorities. In the 1992 GEIS, cultural resources were addressed as one of the major environmental issues. In GEIS Chapter 6, a background of these environmental resources and a review of the then-existing authorities (in addition to SEQRA) was

provided, noting “the revised, shortened and simplified EAF should still remain as an attachment to the drilling permit application form (FGEIS page 31).” The simplified EAF includes cultural resources and offers the New York State Office of Parks, Recreation, and Historic Preservation (OPRHP, the State Historic Preservation Office) as a source for information along with the DEC Division of Construction Management-Cultural Resources Section and the DEC Division of Regulatory Affairs-Regional Office. There was limited discussion of the potential cultural resource issues beyond that identified on pages 6-16, 7-7, and 16-11 through 16-12. Further, although the 1992 GEIS highlighted the need for consultation between NYSDEC and the OPRHP, there was no formal process for consideration of cultural resources outlined.

Despite the length of time since the 1992 GEIS was issued, the 2009 DSGEIS and the RDSGEIS provide no update or reaffirmation of the authority-driven procedures for taking potential impacts to cultural resources into account beyond referring back to the 1992 GEIS. For example, how will tribal consultation be addressed given the 2009 DEC policy, *Contact, Cooperation, and Consultation with Indian Nations*:

> “’Affecting Indian Nation interests’ means a proposed action or activity, whether undertaken directly by the Department or by a third party requiring a Department approval or permit, which may have a direct foreseeable, or ascertainable effect on environmental or cultural resources of significance to one or more Indian Nations, whether such resources are located on or outside of Indian Nation Territory.”

In the RDSGEIS there is limited new discussion of cultural resource issues despite comments provided during the scoping process by the New York Archaeological Council (NYAC) dated December 11, 2008, outlining the potential loss of valuable scientific information should no consideration be given to these finite resources. NYAC reinforces the direct impacts to archaeological deposits that can result from any ground disturbing activity and offers comments on potential indirect impacts, such as vibration from drilling and increased vehicular traffic that could impact fragile archaeological deposits, or the potential for loss or degradation of the information that could be gleaned from specialized analyses of archaeological features that may result from changes to the soil matrix with the introduction of chemical additives as well as the potential for indirect (visual, vibration) impacts to historic architectural resources. Despite the availability of these comments, the additions to the RDSGEIS focus solely on the potential for visual impacts but disregard NYAC’s other recommendations, a notable deficiency in the 1992 document.

In \RDSGEIS Chapter 3, there is no mention of cultural resources relative to SEQRA beyond the reference back to the 1992 findings. In Chapter 6, there is no discussion of cultural resources; while the 1992 document and its findings are incorporated by reference and this chapter is intended to address new issues, this is a missed opportunity to consider potential impact to cultural resources. Consider the potential situation where a cultural resource, such as the remnants of an old water-powered mill complex that once was the economic hub for a small community or what remains of an historic vessel scuttled during a military skirmish, is submerged or partially submerged in an anaerobic environment. With a reduction in stream flow there is the potential to degrade the resource, rendering it subject to deterioration and potential loss. Without consideration of a broadly defined area of potential effect at the outset when the siting application and all its associated contingencies (e.g., well pads, gathering lines,

distributions lines, access roads, resource or water needs, etc.) is reviewed, there is the potential to impact cultural resources.

The RDSGEIS does note in Chapter 8, Table 8.1, that OPRHP has a role in "well siting" and in "new in-state industrial treatment plants" but these are shown with an asterisk, with the caveat "role pertains in certain circumstances." On page 8-6, it is noted that "[i]n addition to continued review of well and access road locations in areas of potential historic and archeological significance, OPRHP will also review locations of related facilities such as surface impoundments and treatment plants." On page 8-37, the State Historic Preservation Act (SHPA) is brought into play with respect to dam safety permitting criteria and thresholds for resource consideration. And in Appendix 14 (Department of Public Service Environmental Management & Construction Standards and Practices –Pipelines), cultural resources are listed under the portion of the checklist for "Procedures for the Identification and Protection of Sensitive Resources."

Thus, the big issue that has not been adequately outlined and addressed is how cultural resources will be handled in the overall permitting process; in particular, what is the procedural means and proposed agency coordination for cultural resources identification, and impact evaluation, minimization, avoidance, mitigation?

8.2 Mitigation

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would be considered when designated significant visual resources associated with historic resources are present and within the view shed of proposed wells. However, in order to determine whether there is a view shed impact on a historic resource the resource itself must be identified, and evaluated before a determination of impact can be made. Because the RDSGEIS does not, as noted, indicate how this will be done, it is impossible to evaluate whether the process for impact identification and mitigation pursuant to SEQRA will be adequate.

The same can be said for ***all*** potential cultural resource impacts, such as those to archaeological sites which are rarely visible on the surface – mitigation measures would be considered once any resources have been identified, evaluated for significance, and a determination made that the impact cannot be avoided or minimized. It is expected that this process is to be undertaken during consideration of well siting applications (which should take into account gathering and distribution lines, access roads, all potential ground-disturbing impacts as well as potential indirect impacts [i.e., vibration, chemical, visual, etc.]). Unfortunately, this approach does not allow the public adequate review of possible mitigation efforts.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate cultural resource impacts of HVHF, and use this information to refine the cultural resource mitigation requirements for future permit applications.

8.3 EAF and EAF Addendum

As noted above, the process for addressing potential cultural resource impacts is not fully developed beyond the EAF checkboxes and DEC review of the application.

9.0 Aquatic Ecology

The assessment of aquatic ecology issues focused on the following items:

- Potential for impairment of the "best use" classifications of the State's surface waters due to cumulative impacts.
- Potential for the alteration or degradation of critical aquatic habitat for aquatic species with limited distributions and sensitivity to water quality, such as trout and salamanders (e.g., the common mudpuppy (*Necturus maculosus*).
- Potential for aquatic habitat fragmentation (i.e., the isolation of existing populations).

LBG's review of Sections 6.1.1.2, 6.1.1.3 and 6.1.1.4 of the RDSGEIS indicates that the document does not fully characterize the potential environmental impacts leading to the potential degradation of a stream's best use classification, and the alteration of aquatic habitats and ecosystems due to direct and cumulative impacts. The RDSGEIS inadequately addresses the potential for the regulated development of high-volume hydraulic fracturing to alter critical aquatic habitat for sensitive species, specifically trout and salamanders, and no provisions are made in sections 7.1 and 7.4 to require standard mitigation measures to ensure degradation is avoided.

Pursuant to NY State Environmental Conservation Law regulations, Chapter X - Division of Water, Article 2, Part 701, all fresh surface water classes have a general condition that does not allow the discharge of wastes to impair the best usage of the receiving water, and all surface water use classifications "shall be suitable for fish, shellfish, and wildlife propagation and survival." The regulations provide for further discharge restrictions to surface waters that occur within the RDSGEIS study area, including:

- Part 701.20: c.2 – waters that contain "critical aquatic habitat for fishes, amphibians, or aquatic invertebrates listed as endangered, threatened, or of special concern in Part 182 of this Title"; d.3 "small trout spawning streams;"
- Part 701.25 a. – waters that are labeled with the symbol (T) are "classified waters in that specific item are trout waters. Any water quality standard, guidance value, or thermal criterion that specifically refers to trout or trout waters applies;" and,
- Part 701.25 b. – waters that are labeled with the symbol (TS) are "classified waters in that specific Item are trout spawning waters. Any water quality standard, guidance value, or thermal criterion that specifically refers to trout, trout spawning, trout waters, or trout spawning waters applies."

The purpose of the discharge designations is to provide further protection to these waters by defining their best use as the maintenance of aquatic species diversity and populations of sensitive or diminishing species that are sensitive to the degradation of water and habitat quality. The combined land use changes caused by well pad development, roadway network improvements and expansion, and supporting

infrastructure should be described within the RDSGEIS at a watershed scale that is practical to the management of aquatic resources.

To assist in defining a potential scale, LBG prepared maps that depict the frequency, spatial distribution and arrangement of discharge restricted sensitive aquatic environments (trout streams) at two watershed scales (See Figures 1 and 2). Figure 1 shows the distribution of streams with NYSDEC discharge designations for trout within the Unadilla river watershed, a large tributary to the Susquehanna River with a 520 square mile watershed. Figure 1 shows the number of and connectivity between patches of existing stream habitat and populations of trout, and presumably other sensitive aquatic species. Figure 2 shows the Lower Butternut Creek watershed at the Hydrologic Unit Code (HUC) 12 level, with a 52.16 square mile watershed. Lower Butternut Creek is a tributary of the Unadilla River. At this scale, Figure 2 can be used as a planning level tool to depict aquatic habitat cores, islands, and corridors for a single or multiple populations of aquatic species. The scale is also practical for relating well pad and ancillary features with potential impacts and mitigation considerations. In the RDSGEIS, NYSDEC should use similar planning tools to evaluate more thoroughly potential impacts to aquatic habitat.

Table 5 below summarizes the watershed features of size, length of trout supporting (T) and trout spawning (TS) designated waters, and length of existing roads for both figures.

Table 5
Watershed Statistics

Watershed	Watershed Size (sq. miles)	Non-Trout Waters (miles)	Trout Supporting/ Trout Spawning Waters (miles)	Existing Roads (miles)
Unadilla River	520	587.63	461.85	1488
Lower Butternut Creek	52.16	88.26	49	134

Construction of well pads, access roads and supporting infrastructure may impact two major watershed processes which could have multiple cumulative effects on surface waters.

The first process is the increase in concentrated runoff from construction sites due to precipitation or snow melt through the re-routing and concentrating of diffuse overland sheet flow into roadside ditch networks, and the reduction in soil infiltration and permeability due to land development (or changes in water supply distribution) (Rosgen 2006, Forman et al. 2003, Leopold and Langbein 1960).

Second, the increase in sediment from the introduction of miles of new access roads with a gravel base, unpaved shoulders, and/or unconsolidated drainage conveyances/ditches, and stream crossings is a process that can lead to changes in sediment supply. Gravel roads, even when properly constructed and maintained, provide a source of sediment, especially during high traffic periods (Rosgen 2006, Forman et al. 2003, Reid and Dunne 1984). Each of these items is discussed below.

9.1.1 Land Use

Sections 5.1.1, 5.1.2 and 5.1.3 of the RDSGEIS describe the extent of land disturbance during the drilling and fracturing stage for a well pad and ancillary features (access

roads, utility corridors, compressor stations, etc.). The average total disturbance was estimated at 7.4 acres for a multi-well pad and 4.6 acres for a single well pad.

Section 5.1.4.2 of the RDSGEIS states that the spacing of disturbances from horizontal wells with multiple wells drilled from common pads is “up to 640 acres,” which is approximately one well pad per square mile. An “on average” spacing estimate is not provided; therefore, a typical disturbance footprint spacing has not been quantified. Analyses of cumulative impacts at a watershed scale require a practical spacing or range of spacing to better evaluate the need for regulatory limitations on well pad densities. If truly representative of the affected acreage, a single 7.4 acre multi-well pad represents approximately 1.5 percent of the area within a square mile.

A common component of construction is the clearing, grading and compaction of land within the disturbance footprint. These actions impact the naturally occurring drainage patterns outside of the disturbance footprint by re-routing and concentrating diffuse overland sheet flow produced by precipitation or snow melt (Leopold and Langbien, 1960; Leopold, 1994), re-directing this water through surface conveyances such as a ditch network (Foreman et al. 2003), which can change the timing and path of water supplied to surface waters within the watershed (Rosgen, 2006) or the hydrologic regime (Poff et al., 1997). The RDSGEIS does not specifically address these processes or address potential mitigation measures for inclusion as permit conditions within the regulatory program.

In reference to partial reclamation of the well pad, Section 5.16.1 states that “[s]ubsequent to drilling and fracturing operations, associated equipment is removed. Any pits used for those operations must be reclaimed and the site must be re-graded and seeded to the extent feasible to match it to the adjacent terrain. Department inspectors visit the site to confirm full restoration of areas not needed for production.”
The intention of partial reclamation of a pad during the production phase is to further reduce the footprint of the disturbance. However, this section does not describe details about how long each phase lasts, does not provide a reclamation time table, or performance standards. Therefore, it is difficult to classify the disturbance as a temporary or permanent impact. The section provides insufficient elaboration or methods and does not define the industry standards or success criteria for reclamation activities and the environmental benefits they may provide; therefore, the value of reclamation as mitigation is also unclear.

Land use restrictions using impervious area thresholds are used to maintain brown trout populations in suburban watersheds in Delaware, Maryland and Pennsylvania (Kauffman and Brant, 2000) which is based on limiting impervious surfaces to less than 10% coverage of a watershed. Brook trout populations, the very species associated with T and TS stream designations in NY have become extirpated in watersheds with impervious land uses above 4% coverage, and stress upon brook trout populations was inversely related to impervious watershed coverage (Stranko et al., 2008). Brook trout population presence is shown to have a positive relationship with forested watershed coverage above 68% (Hudy et al. 2008). Collectively, this information demonstrates that cumulative watershed land use changes induced by HVHF that impact forested land and increase impervious cover is likely to cumulatively impact NY State designated trout and trout spawning waters which could well lead to the loss of the waters’ best use designations. NYSDEC should address these issues in the RDSGEIS. In addition, related impacts to tourism are not discussed here but should be as these impacts are an

indirect effect of natural habitat degradation and natural habitat is an established State tourism asset.

9.1.2 Access Roads

Section 5.1.1 of the RDSGEIS states “industry estimates an average access road size of 0.27 acre, which would imply an average length of about 400 feet for a 30-foot wide road. Permit applications for horizontal Marcellus wells received by the Department prior to publication of the 2009 DSGEIS indicated road lengths ranging from 130 feet to approximately 3,000 feet.” The Executive Summary, Chapter 2 summary of the RDSGEIS states “the Department has determined, based on industry projections, that it may receive applications to drill approximately 1,700 - 2,500 horizontal and vertical wells for development of the Marcellus Shale by high-volume hydraulic fracturing during a ‘peak development’ year. An average year may see 1,600 or more applications. Development of the Marcellus Shale in New York may occur over a 30-year period. Those peak and average levels of development are the assumptions upon which the analyses contained in this RDSGEIS are based.” Based only on the averages considered in the RDSGEIS, an average of 1,600 wells annually, each requiring 400 feet of new road, according to the RDSGEIS would result in over 121 miles of new, likely gravel, roads annually. This would be over 3,600 miles of new roads over 30 years. The RDSGEIS does not address the potential impact of the additional roads on aquatic resources, especially streams with sensitive species.

Stream drainage density relative to road density across a watershed is indicative of the interconnectivity of the roadway drainage system with the stream ecosystem (Foreman et al. 2003). In a regional study of the distribution of brook trout in their native range, average road densities of 3.2 km/sq. km was shown to be a predictor of watersheds that are not likely to support intact brook trout habitat (Hudy et al. 2008). Road density within the lower Butternut Creek watershed is 2.57 miles/sq. mile and the stream density is 2.63 miles/sq. mile. Within the lower Butternut Creek watershed, the stream network is less likely to be designated as Trout or Trout Spawning in areas where roads cross the stream more frequently. For instance, the stream network is designated as Trout or Trout Spawning stream segments are crossed by roads 38 times, and non-trout where stream segments are crossed by roads 54 times or more (Figure 2). While other land use factors can be at play here, road density within a watershed is positively correlated with stream habitat condition. The RDSGEIS should exam available literature on this topic to aid in the assessment of potential long term impacts to trout populations within affected watersheds due to watershed level changes. It is likely that some watersheds currently supporting trout populations are at or near the tipping point of trout sustainability. The RSDGEIS does not address how future HVHF development may affect native trout populations and other sensitive aquatic species.

Road crossings have been identified as a source of habitat fragmentation within linear aquatic systems by forming barriers to fish passage and altering the continuity of fluvial processes (e.g. sediment transport and disconnecting a stream from its floodplain) (Foreman, 2003). Road crossing structures can also change the transport of Large Woody Debris (LWD) (Foreman et al. 2003). LWD is important as an indicator of trout habitat quality (Flebbe and Dolloff, 1995) and in routing, storing and sorting sediment in fluvial landforms (Fisher et al. 2010, Lassettre and Harris 2001, Gomi et al. 2001 and Montgomery et al. 1995).

The alteration of fluvial processes caused by watershed development includes increased peak flows and mobilization of sediment from watershed and stream channel sources (Leopold 1994). Gravel roads, particularly construction and repair of gravel roads, have been shown to be a source of sediment in watersheds (Rosgen 2006) and contribute to habitat degradation (Logan, 2003). Heavy vehicle traffic on gravel roads, up to four heavy vehicles per day, has been shown to contribute up to 130 times more sediment to streams than paved roads (Reid and Dunne, 1984). The drilling and fracturing process can require tens to hundreds of trips by heavy vehicles each time a new well is constructed, thus increasing the likelihood of new sediment loadings to the local stream.
Currently New York State provides no regulatory guidance for stream crossing design which maintains Aquatic Organism Passage (AOP). Vermont Department of Environmental Conservation, Watershed Management Program has developed stream crossing design guidance and stream crossing assessment tools which support AOP and natural channel morphology (The Vermont Culvert Geomorphic Compatibility Screening Tool, 2008 and The Vermont Culvert Aquatic Organism Passage Screening Tool, 2009). These tools can be used to design habitat sensitive crossings at new roads and find mitigation through retrofit or replacement of existing non-habitat sensitive crossings. The Massachusetts Department of Environmental Protection has developed guidance for maintaining gravel roads, ditch networks and stabilizing cut slopes to prevent erosions and reduce sediment inputs to the watershed (The Massachusetts Unpaved Roads BMP Manual, 2001). The adoption or incorporation of these practices as standard BMP measures within the regulatory program should be addressed within the RDSGEIS as a means to minimize potential impacts.

Section 6.4.3 of the RDSGEIS provides an incomplete characterization of potential environmental impacts to endangered and threatened species. While Chapter X, Part 701.20: c.2 states “critical aquatic habitat for fishes, amphibians, or aquatic invertebrates listed as endangered, threatened, or of special concern in Part 182 of this Title” includes discharge designations for waters with species of special concern, the RDSGEIS does not adequately recognize critical habitats for aquatic species of special concern, nor does it provide a complete list of species of special concern that are dependent on aquatic habitats as part of their natural life cycle. There is insufficient evaluation of species of special concern and potential cumulative impacts to threatened, endangered or special concern species within the RDSGEIS.

9.1.3 Recommendations

Based on the review of the RDSGEIS, LBG has found that the document does not adequately address the potential direct and cumulative impacts of HVHF on aquatic resources, New York State designated trout and trout spawning waters, and the potential for the loss of the waters’ best use designations. Recommendations to address the deficiencies of the RDSGEIS are provided below.

1. The RDSGEIS should provide a technically supported evaluation method to assess the anticipated changes to land use and road networks at a watershed level and the potential impact to aquatic habitat and sensitive aquatic species.

2. The RDSGEIS should define the restoration standards and success criteria for well pads, access roads and other short term and long term disturbances,

and timelines so that the temporal impacts of these activities and the environmental benefits of site reclamation are clearly defined.

3. Currently New York State does not provide regulatory guidance for stream crossing design which maintains Aquatic Organism Passage (AOP).The adoption or incorporation of these practices as standard BMP measures within the regulatory program should be addressed within the RDSGEIS as a means to minimize potential impacts.

9.1.4 Aquatic Ecology References

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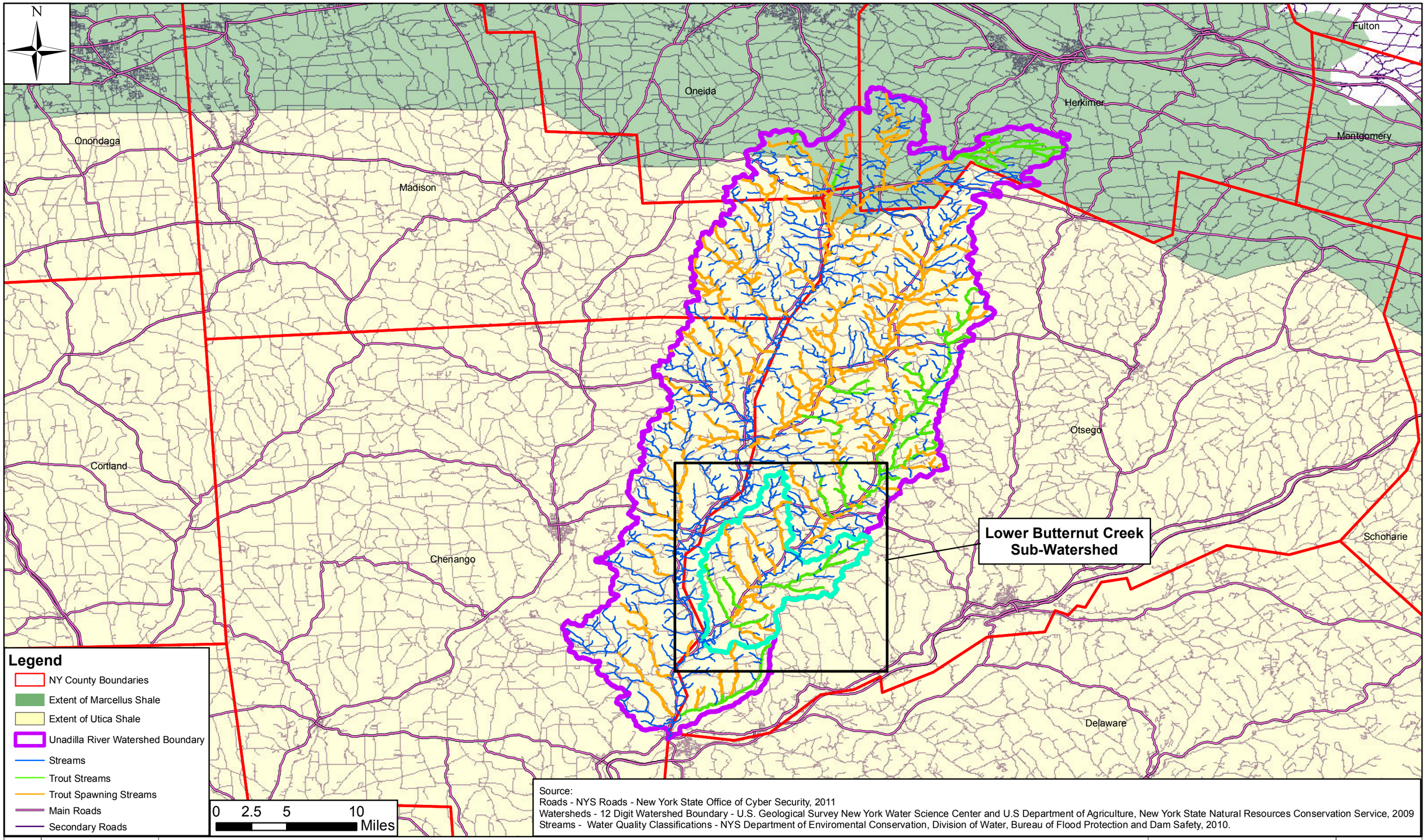


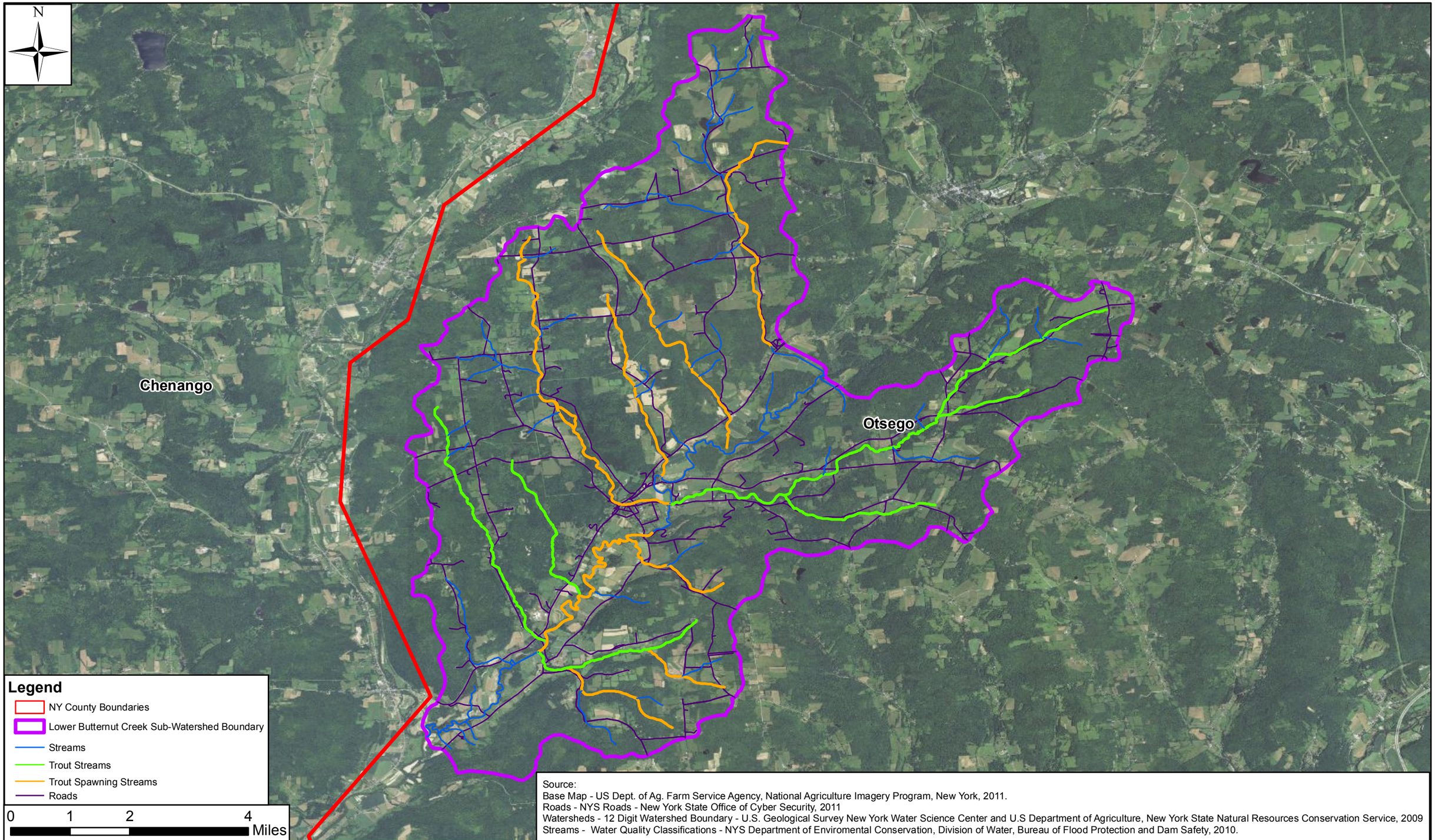
Natural Resources Defense Council

UNADILLA RIVER WATERSHED MAP

NEW YORK

The Louis Berger Group, Inc.
412 Mt. Kemble Ave
Morristown, NJ

FIGURE 1



Source:
Base Map - US Dept. of Ag. Farm Service Agency, National Agriculture Imagery Program, New York, 2011.
Roads - NYS Roads - New York State Office of Cyber Security, 2011
Watersheds - 12 Digit Watershed Boundary - U.S. Geological Survey New York Water Science Center and U.S Department of Agriculture, New York State Natural Resources Conservation Service, 2009
Streams - Water Quality Classifications - NYS Department of Enviromental Conservation, Division of Water, Bureau of Flood Protection and Dam Safety, 2010.

Natural Resources Defense Council

LOWER BUTTERNUT CREEK SUB-WATERSHED MAP

NEW YORK

The Louis Berger Group, Inc.
412 Mt. Kemble Ave
Morristown, NJ

FIGURE 2

Attachment 8

Kevin Heatley, M.EPC LEED AP

Professional Review & Comment

on

Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (Revised September 7, 2011)

January 5, 2012

Prepared for:

Delaware Riverkeeper Network

Prepared By:

Kevin Heatley, M.EPC LEED AP

Restoration Ecologist

EXECUTIVE SUMMARY

This review of the New York State Department of Environmental Conservation (NYDEC) revised draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program (issued September 7, 2011) was prepared in response to a request by the Delaware Riverkeeper Network to provide expert opinion on issues of terrestrial and restoration ecology. The ecological health and integrity of the forested landscapes located within watersheds has a direct bearing on both the water quality and the biotic composition of the streams and aquatic resources of the Delaware River and other major drainages of the Marcellus and Utica region. Mitigation of land disturbance impacts, such as those associated with unconventional fossil fuel extraction, is critical to ecological sustainability.

The NYDEC recognizes in section 1.2 of the RDSGEIS that it is required by NY state law to "conserve, improve and protect its natural resources and environment . . ." However, the agency openly, and correctly, acknowledges that this mandate cannot be achieved for terrestrial habitats and wildlife resources in the state under the proposed RDSGEIS mitigation recommendations. According to section 7.4.1, "Significant adverse impacts to habitats, wildlife, and biodiversity from site disturbance associated with high-volume hydraulic fracturing in the area underlain by the Marcellus Shale in New York will be unavoidable." The agency presents no mitigation option, such as aggressive region-wide restrictions on the spatial and/or temporal scale of this land disturbance sufficient to negate the undesirable ecological impacts of shale gas development.

The RDSGEIS identified four major areas of concern with respect to ecosystems and wildlife:

1. Fragmentation of habitat
2. Potential transfer of invasive species
3. Potential impacts on endangered and threatened species
4. Use of certain state-owned lands

While the RDSGEIS correctly emphasizes the importance of habitat fragmentation on terrestrial vertebrate species (in particular avian organisms) it fails to document the long term ecological consequences of fragmentation, deforestation, increasing forest edge and reduced surface permeability on desirable forest regeneration, surface water quality, soil chemistry, biodiversity, and sustainable ecosystem services.

Unfortunately, the mitigation measures proposed fail to fully address fragmentation and landscape connectivity issues for the majority of the affected ecosystems. In addition, the proposed invasive species best management practices lack the following key components:

- Quantifiable control metrics
- Latent seed bank management
- Forest edge management

The RDSGEIS also fails to provide any effective regulatory guidance and/or mandates regarding the final ecological restoration of ecosystem structure and function to well pads, pipelines, access road sites, and other related infrastructure upon cessation of natural gas extraction activities.

As written, the revised draft RDSGEIS presented by the NYDEC assures that widespread, dramatic changes in both the current integrity, and the future successional trajectory, of the watersheds and forests in the Marcellus and Utica regions will occur should the anticipated level of landscape industrialization occur. Changes in the successional trajectory (the type of tree species regenerating in the forest understory and that will ultimately comprise the forest canopy) will cause cascading ecological consequences. These changes are likely to result in an undesirable diminution of the ecosystem benefits and services currently provided by these biotic communities. Cascading ecological effects and consequences are probable and will require costly management interventions of significant spatial and temporal scale in order to achieve system restoration.

DISCUSSION

A careful review and analysis of the draft NYDEC RDSGEIS reveals a number of areas of concern with respect to the maintenance of the ecological integrity of terrestrial ecosystems and the corresponding impacts upon aquatic resources. In particular the RDSGEIS does not adequately provide for the protection and sustainable regeneration of critical headwater forests within the Delaware River drainage. Forested ecosystems are the dominant land cover type (57%) within the areas of potential shale gas extraction in the State of New York. This canopy cover is of extreme importance to both the quality and quantity of water that flows within the Delaware River drainage.

Forests filter contaminants, moderate stream temperatures and buffer flow volumes associated with precipitation events. They are the structural foundation upon which the ecological integrity and health of the basin's biological resources are built. The link between percent forest cover and water quality is clearly established in the scientific literature. As an example, reductions in forest cover are directly correlated with negative changes in water chemistry, such as increases in nitrogen, phosphorus, sodium, chlorides, and sulfates, and with reductions in stream macroinvertebrate diversity (Jackson and Sweeny 2010).

A healthy, viable forest canopy creates tangible economic value that accrues directly to local and regional communities. This value comes both from forest-dependent industries and from the ecosystem services (air filtration, climate regulation, water purification, etc.) that the forest provides. For instance, a 2002 survey of 27 water suppliers found that for every 10% increase in forest cover within a municipal watershed, the costs of water treatment and purification decreased by approximately 20% (Ernst, Caryn, Gullick and Nixon 2004). In New York State, forest-dependent industries are estimated to generate nine billion dollars of economic activity on an annual basis (North East State Foresters Association 2001).

Forest fragmentation as a result of anthropogenic landscape modification is well recognized within biogeographic theory and conservation biology as a leading cause of local species extinctions (extirpation). It can also cause dramatic shifts in the floral and faunal composition of woodland communities. Sub-lethal impacts to floral and faunal

populations (population isolation, reduced genetic fitness and diversity) have also been associated with disruptions to forest connectivity (Clark, et.al. 2010).

Species dependent upon large, intact areas of interior, or "core" forest and those with limited dispersal abilities are at particular risk from forest fragmentation. A large body of scientific literature associated with neotropical migratory birds clearly links the survival of many of these species to the preservation and restoration of core forest habitat. The Cerulean warbler *(Dendroica cerulean*), a species of special concern in New York State, is a prime example. These populations are already in decline due to massive reductions in the amount of intact core forest. Even if the remaining interior forest habitat is preserved, the extensive fragmentation of the rest of the forested landscape will effectively preclude these areas from reconnection and restoration as interior forest habitat.

As pointed out by Semlitsch and Bodie (2003), the long-term persistence of many amphibian populations depends on the availability of vernal (seasonal) woodland pools and the surrounding, connective forest habitat. The ability of local populations to safely disperse is critical for the survival of these species. For instance, while many species of salamanders return to where they hatched to breed and lay eggs, it has been shown that they will use other vernal pools for breeding if their vernal pool of origin has been disturbed (if it is within their migration distance capacity). Linear disturbance corridors such as roadways and pipeline right-of-ways can create impermeable barriers to movement and effectively isolate populations of these organisms from alternative breeding sites. Isolated populations are at greater risk for extirpation (local extinction). The Jefferson salamander (*Ambystoma jeffersonianum*), another species of special concern in

New York, is an example of an amphibian that will be at risk should significant forest alterations occur.

The development of shale gas infrastructure in the New York and Pennsylvania region will have profound forest fragmentation impacts. Recent modeling work performed by the Pennsylvania Chapter of The Nature Conservancy indicates that approximately 2/3rds of the Marcellus well pads to be built in Pennsylvania will be located in what is currently forested habitat (TNC 2010). Coupled with the associated connective infrastructure of access roads and pipeline right-of-ways (ROWs), disruption of vital ecological processes is assured.

Fragmentation creates an increase in the amount of forest edge (the interface between forest and non-forest). This transitional zone or "ecotone" is fundamentally different in structure and functionality from an interior forest system. Edge habitat is characterized by increased light levels on the forest floor, reduced soil moisture, and a high degree of biological invasion from non-native invasive organisms. Dramatic changes can occur in the soil chemistry and associated micro biota. The top layer of the soil profile, the rich organic duff, begins to dry out and the primary decomposition community begins to shift from fungal to bacterial. Changes in the soil micro biota will result in shifts in the macro biotic community structure. The regeneration of desirable tree species (the successional trajectory) will be affected, potentially impacting the level of valuable ecosystem benefits supplied by the forest. These changes have direct economic implications to both landowners and society. Invasive species, for instance, have been estimated to cost the U.S. economy approximately $120 billion dollars per year (Pimintel et al. 2004).

Invasive organisms within terrestrial forest environments tend to be early successional species that respond favorably to site disturbance. Disruption of native plant cover and the exposure of the forest floor to sunlight provide an opportunity for these organisms to establish satellite populations. These populations eventually radiate out into the adjacent forest, displacing native species and retarding desirable tree regeneration (Bennet et al. 2011). Dispersal (vectoring) mechanisms and/or corridors are required in order for these non-native species to colonize new locations and the access roads, pipelines, and vehicular traffic associated with natural gas extraction are ideally configured to serve this function. Long beyond the point when wells are decommissioned, the landscape legacy of forest edge spreading outward from pipeline corridors, access roads, well pads, and related infrastructure will continue to disrupt ecosystem functioning as non-native organisms repeatedly colonize exposed areas and impede desirable tree regeneration.

Invasive species suppression and the eventual restoration of these disturbed sites to forested systems will require resources of a significant financial and temporal scale. While published information is scarce, it is in the professional experience of restoration practitioners in this region that the reasonable reconstruction of forest canopy and understory diversity can cost between $4,000 and $10,000 per acre. The suppression of invasive plant species is also a major, recurring expense with the initial years' treatment often costing between $1,000 and $2,500 per acre. Invasive treatment in subsequent years typically drops in cost by approximately 50% per year during the first three years of suppression. Treatment and monitoring will need to continue on an annual basis until forest canopy closure is re-established and the resulting changes in light penetration and soil conditions begin to favor native species.

As the effects of forest fragmentation may not immediately manifest themselves following the disturbance, monitoring is often suggested as a methodology to balance and modify the level of fragmenting activity in accordance with the conservation of forest-related ecosystem services. Unfortunately, these effects may not be linear in nature and thus are not always amenable to an adaptive management approach. Biological systems may possess thresholds that provide little indication of impending adverse impacts until sudden system collapse.

It is from within this conceptual framework that a review of the NYDEC Revised Draft RDSGEIS was undertaken and the following concerns identified:

Infrastructure Density-related Ecological Impacts -

- While mandatory unitization of production areas is in effect in New York, this spacing regime is geared toward maximization of gas extraction and not natural resource protection. Preliminary research results already point towards pad density as a significant indicator of potential landscape level impacts to water quality (Academy of Natural Sciences 2011). The RDSGEIS makes no mention of utilizing ecological planning units (such as the sub watershed) or ecological carrying capacity models. This is necessary to assure the industrial development pattern is consistent with the maintenance of ecological integrity.

- Density of infrastructure is also directly correlated to percent impermeable surface within subwatersheds. Increased impermeable surface area will disrupt both surface and subsurface hydrologic regimes within currently forested systems

resulting in shifts in species composition and functional benefits. For instance, it is widely accepted among watershed managers that negative changes in water quality and quantity become clearly evident when impermeable surface begins to exceed 10% of a given watershed area. The RDSGEIS-proposed mitigation strategies do not address allowable levels of impermeable surface within ecological planning units such as the subwatershed.

Forest Fragmentation

- While the requirement for ecological assessments and site-specific mitigation measures on well pads placed in grasslands of greater than 30 acres (in grassland focus areas) and for forest patches of greater than 150 acres (in forest focus areas), is helpful this approach is, in essence, ironically fragmented. It completely fails to address the importance of landscape connectivity between patches. As such, it will not protect the landscape-level ecological processes that maintain regional forest integrity. It will also fail to protect connective corridors vital to the movement of plant and animal populations in response to climate change. A preferable methodology would be to set maximum allowable levels of deforestation and fragmentation based upon ecological planning units such as the subwatershed.

- It is strongly recommended that a comprehensive, ecosystem-based plan guide the decision-making and permitting process in place of the piecemeal approach to land use planning and the protection of watershed resources set forth in the RDSGEIS. Setting maximum thresholds and spatial parameters for percent forest cover loss

and forest connectivity would assure that density levels and cumulative impacts of natural gas extraction do not exceed the ability of the regional ecosystem to absorb these activities.

- The RDSGEIS correctly emphasizes the importance of minimum patch sizes and landscape connectivity in protecting terrestrial wildlife habitat and/or the human recreation associated with such wildlife. However, no discussion or analysis is present regarding the impact that fragmentation and increasing edge habitat will have upon long term forest successional trajectory and associated biodiversity.

- No analysis has been presented in the RDSGEIS regarding the potential diminution of critical ecosystem services associated with the disruption of forest cover and soils (carbon sequestration and storage, air filtration, watershed flow rates and volume, surface water quality and thermal condition).

- Section 6.4.1.2 estimates that a mere 7% of the forest cover underlain by the Marcellus Shale in NY occurs on State-owned land. However, section 7.4.4 proposes a ban on surface disturbance within state forests and state wildlife management areas only. It is important to understand that this prohibition is not based upon any substantive <u>ecological</u> differences between forests under different ownership.

- Section 7.4.4 gives several reasons for prohibiting surface disturbance on State-owned land including: "Increased light and noise levels would be likely to have significant impacts on local wildlife populations, including impacts on breeding, feeding and migration" and "The local wildlife populations could take years or even

decades to recover." These concerns are equally applicable to privately-owned forests, yet full mitigation of these identified impacts to wildlife is not addressed for the remaining 93% of the forest cover in the state. In particular, noise reduction strategies are entirely omitted from section 7.4.1.1 (BMPs for Reducing Direct Impacts at Individual Well Sites).

- Section 7.4.1.1 requires full cutoff (downward) lighting only during bird migration periods. As the ecological impacts of artificial night lighting across a range of species are well documented in the scientific literature, this requirement should be extended year-round.

- Section 7.4.1.1 fails to address BMPs for placement and maintenance of gathering pipelines. As this infrastructure is fundamental to well pad development, and has the potential to disrupt a greater net acreage than the actual pad, BMP recommendations should be developed.

- Section 7.4.1.1 fails to address BMPs for placement and mitigation of compressor station impacts.

- Section 7.4.1.2 indicates that for forest patches of 150 acres or more (within Forest Focus Areas) where the DEC issues a disturbance permit after reviewing the required Ecological Assessment, "enhanced monitoring of forest interior birds during the construction phase of the project and for a minimum period of two years

following the end of high-volume hydraulic fracturing activities (i.e., following date of well completion) would be required." While this is an important recommendation, such enhanced monitoring should be extended to less mobile species sensitive to the radical changes in forest floor light and moisture levels that forest fragmentation will cause. Forest-dwelling amphibian species are at a particular risk of extirpation (local extinction) following the loss of interior forest conditions given their limited ability to traverse across linear landscape barriers such as roadways and pipeline ROWs.

- As connectivity between forest patches is critical to allowing for species migration, dispersal, and the continued genetic fitness of terrestrial species, mitigation strategies protective of this landscape level feature should be required. The RDSGEIS does not presently address protection of landscape connectivity and mitigation of disruptions to connective corridors.

- Definition of a disturbed area – clarification should be made as to the minimum size that defines a disturbed area.

- Section 7.4.1.3, *Monitoring Changes in Habitat* recommends, on parcels meeting the threshold criteria in grassland and forest focus areas, that monitoring of disturbance effects should occur during the drilling process and for a minimum of two years following well completion. While monitoring is indeed a valuable tool, effective implementation of operational changes (adaptive management) following and in

response to ecosystem disruption is not always possible. Ecosystem response to disturbance may not follow a linear pattern as previously unknown tolerance thresholds may be crossed. Sudden system collapse and the loss of valuable structural and functional features of an ecosystem may occur even in the absence of discernible advance indicators of stress. A more appropriate response would be to apply the precautionary principle and study the likely impacts prior to widespread, and potentially irreversible, landscape modification.

Invasive Species Introduction & Management

- It is recommended that section 6.4 be expanded to include an analysis of the threat potential to forest health from the inadvertent introduction and facilitation of the spread of invasive terrestrial invertebrates and pathogens. The current analysis only considers invasive plants and aquatic organisms.

- The construction of infrastructure necessary to develop the Marcellus and Utica shales will entail the movement of large fleets of vehicles and equipment from various sections of North America. It will also entail the movement of large numbers of transient laborers and technical personnel from across the United States. This activity carries an inherent risk of acting as a vectoring mechanism for a number of threats to forest health. The RDSGEIS should review this potential mechanism of invasive threat and propose mitigation strategies.

- Section 6.4 should also be expanded to include an analysis of the impact that massive increases in forest edge habitat will have upon the incursion and establishment of invasive plant species. Edge habitat is inherently attractive to the type of plant species that display invasive characteristics. Invasive plants tend to be early successional species adapted to disturbed sites. The ecotone between forest and grassland is an area generated by recent disturbance and thus presents ideal conditions for these opportunistic, rapidly-reproducing species. Periodic re-infestation of edge habitat by invasive plant species is also highly probable given the high light levels and frequent deposition of wind-borne and bird-deposited seeds in such areas. The creation of edge habitat on the scale anticipated by natural gas infrastructure is likely to result in chronic, regional infestations of undesirable species that will require regular, and expensive, control interventions. The creation of forest edge is, in and of itself, an important precursor to biological invasion.

- Section 7.4.2.1 fails to include compressor stations and pipeline ROWs in the requirements for invasive species best management practices.

- Section 7.4.2.1 indicates that an invasive species survey "should be conducted by an environmental consultant familiar with the invasive species in New York." It is recommended that the word "should" be replaced by "must".

- It is recommended that the invasive species survey required under section 7.4.2.1 stipulate that percent aerial cover be classified <u>for each</u> identified invasive plant

species on the site. Identification of baseline infestation levels is critical to determining target levels of cover reduction and control.

- Section 7.4.2.1 fails to provide any measurable metric, such as percent cover reduction from pre-disturbance levels, for quantifying levels of invasive control. The recommendation strategy that, "Any new invasive species occurrences found at the project location should be removed and disposed of appropriately" should be qualified to include the latent seed bank in the soil.

- Section 7.4.2.1 fails to define the temporal timeframe of responsibility for invasive suppression. The seeds of many invasive plant species can lie dormant in the soil for years. This latent seed bank creates a reservoir for future outbreaks following soil disturbance. It is critical that a long term monitoring and treatment program be implemented for all sites and associated infrastructure. Monitoring and suppression treatments should continue until final site reforestation and effective closure of the tree canopy.

- Section 7.4.2.1 fails to provide a spatial framework for the area of invasive species control responsibility. Invasive species are highly mobile and akin to a wildfire in their dispersal from initial point of infestation. At a minimum, site developers should be required to manage invasive infestations within all forest edge environments surrounding new pads, pipeline ROWs, and newly constructed access roads. Failure to do so will result in migration of these species off-site and the transfer of the financial burden of control onto adjacent property owners.

- As prevention is more cost effective than control, requirements should be adopted mandating independent site inspections by a qualified ecologist on no less than a semiannual basis until final reforestation and canopy closure occurs. Failing to provide for frequent site inspections assures compliance will be minimal.

Site Restoration

- The RDSGEIS fails to provide any meaningful guidance regarding the ultimate restoration of well pads, pipeline ROWs and access roads to full ecosystem functionality upon decommissioning. Effective restoration requires a comprehensive, site-level assessment of the existing plant community prior to disturbance and the use of local reference ecosystems as templates for restoration. Ecological restoration is based upon the concept of rebuilding degraded areas such that they are structurally and functionally similar to pre-disturbance conditions. Reclamation is NOT restoration. Grassy fields neither function in a biologically similar manner as a forest nor supply the ecosystem benefits of a forest system. The replacement of a decades-old, complex assemblage of woodland species with a simple mix of grasses is not "restoration". It may retard erosion but it does not replace the original functionality and structure of the displaced ecosystem.

- Restoration objectives and planning should be integrated into best management practices and developed based upon a landscape-level analysis. Re-establishing forest connectivity should be a primary goal.

- As the service life of gas extraction infrastructure such as transmission pipelines may extend for decades, mitigation banks and sites where restoration of previously degraded systems might off-set the disturbance for the interim period should be utilized. This will help assure that no net loss of ecosystem benefits occurs within the region.

- Requirements for an independent, qualified restoration ecologist to oversee and inspect site restoration should be developed in order to assure effective compliance.

Summary

As currently proposed, the NYDEC RDSGEIS does not provide an adequate assessment of likely impacts associated with the rapid conversion of forested and rural ecosystems to industrial sites. It also fails to recommend potential mitigation strategies and options that would offset and reduce the "significant" impacts anticipated for native terrestrial ecosystems. Protection of these terrestrial ecosystems is critical to the continued health of the regions' aquatic resources. Inadequate attention has been given to the following vital considerations: density related impacts of infrastructure, forest fragmentation, invasive species, and site restoration. Should the RDSGEIS be adopted in its current form, widespread disruption to forest ecosystems within the upper Delaware River Basin and other watersheds underlain by the Marcellus and Utica formations will occur. Restoration of these systems following the eventual cessation of natural gas extraction will be a monumental cost incurred by both the taxpaying public and adjacent private property owners. It is strongly recommended that the NYDEC

consider a more comprehensive approach to protecting the integrity of the forested landscapes in New York. Setting maximum thresholds and spatial parameters for percent forest cover loss, forest connectivity, and core forest integrity within ecological planning units, such as the subwatershed, would assure that density levels and cumulative impacts of natural gas extraction do not exceed the ability of the regional ecosystem to absorb these activities.

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Attachment 9

Kim Knowlton, DrPH

Kate Sinding
Senior Attorney
Natural Resources Defense Council
40 West 20th Street, 11th floor
New York, NY 10011

January 8, 2012

Re: Comments on the RDSGEIS on NY Marcellus Shale Natural Gas Hydraulic Fracturing

These comments are submitted regarding the Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) governing high-volume, hydraulic fracturing as a method of natural gas drilling in the Marcellus Shale and similar formations in New York State.

I am Senior Scientist in the Health and Environment Program at the Natural Resources Defense Council in New York City, and Assistant Clinical Professor in the Department of Environmental Health Sciences at the Mailman School of Public Health of Columbia University. I received my doctorate in Public Health from Columbia University, and much of my research considers the effects of climate change on human health (my CV is attached). These comments relate to climate change and public health concerns raised by the information described in the RDSGEIS.

Although the RDSGEIS describes greenhouse gas emissions that would be generated by Natural Gas Hydraulic Fracturing operations in the Marcellus and other shale formations in NY State (sec. 6.6), and the means to reduce those health-harming emissions (sec. 7.6), the RDSGEIS lacks critical information about the exacerbating effect climatic changes will have on the uncertainties of drilling operations. Further, climate change is likely to increase the risk to public health from HVHF operations if these operations are conducted without regard to the effects of climate change on the environmental context of drilling operations.
Climate change is likely to increase several key uncertainties in shale gas natural gas hydraulic fracturing operations which are not addressed in the RDSGEIS, yet should be. Several of these climate change and public health-relevant omissions are described below:

1. **More frequent extreme rainfall events.** The public health risks of drill pad operations and waste fluid disposal are likely to be affected by more frequent extreme rainfall events in New York State, as climate change continues. These events and the flooding they can cause need to be factored into the RDSGEIS. Measured changes in the heaviest precipitation events in the Northeastern US increased 67% over the period 1958-2007; and the trend toward heavier precipitation is projected to increase into the 2090s.[1] In New York State in the last 60 years from 1948 to 2006, there has been a statistically significant 56% increase in the most extreme rainfall events, according to the a 2007 study by Environment America.[2] As climate change continues, these extreme rainfall events are projected to continue to occur more frequently.[3] The New York Panel on Climate Change (or NPCC), an expert group of university researchers and climate modelers, investigated climate change's effects on New York City and the surrounding region, and projected that annual precipitation in the New York region will "more likely than not" increase, with mean annual precipitation increasing up to 5% by the 2020s, 10% by the 2050s, and

5-10% by the 2080s.[4] The New York State Climate Action Council's Nov. 2010 *Climate Action Plan Interim Report* noted in its Executive Summary (ES) that, "Summertime rain is expected to fall more often as heavy downpours, leading to more flooding; at the same time, the periods between these rainstorms are likely to be drier, leading to droughts. … Public and private entities will need to assess whether new investments in infrastructure, particularly long-lived infrastructure like power plants and transportation, will be consistent with a low-carbon future, both in terms of GHG emissions and in terms of vulnerability to a changing climate. We should avoid investments that are not highly adapted to a modified climate, such as infrastructure sited in low-lying floodplains."[5] ***DEC should act consistently with the recommendations of the New York Climate Action Plan Interim Report by prohibiting HVHF operations and infrastructure in low-lying areas***.

2. **Changes in floodplain location.** The locations of 50-, 100- and 500-year floodplains are likely to change in New York State, owing to the effects of climate change. Extreme rainfall events are becoming more frequent in the US.[6] This trend was also noted in the recently-released NY State ClimAID report: "Intense precipitation events (heavy downpours) have increased in recent decades, and are likely to increase in future."[7] These extreme precipitation events are occurring in tandem with a long-term increase in annual average precipitation of 0.37 inches per decade since 1900.[8] The advent of extreme precipitation events taken together with a general increase in average precipitation is likely to alter the location and size of floodplains. Altered floodplain locations could dramatically compromise the siting and safety of drilling operations, as well as waste disposal and transport. With the trend to heavy downpours over the past 50 years projected to continue, an increase in localized flash flooding in hilly regions across the state is expected. "Flooding has the potential to increase pollutants in the water supply and inundate wastewater treatment plants and other vulnerable development within floodplains."[9] The most recent state of the science on the effects of climate change on the extent of local floodplains should be applied in the RDSGEIS's consideration of the potential impacts of proposed new drilling in NY State.

   Because increasingly frequent and extreme rainfall events could threaten drilling infrastructure, operations and disposal, such investments should be avoided without a full, detailed mapping of areas at greatest risk from storm and flood damage. This is in line with the Nov. 2010 recommendations of the NY State Climate Action Council in their Climate Action Interim Report.[10] Floodplain maps must be fully updated to include the latest information on how climate change will affect local flood plain locations, taken from downscaled climate model projections.[11]

   Although DEC proposes prohibiting surface disturbances in 100-year floodplains[12], this approach is problematic for several reasons. First, DEC should also prohibit subsurface activity in these areas. Second, the prohibition should apply to additional matters involved in HVHF, such as the siting of pipelines and other potentially sensitive infrastructure, the construction of impoundment ponds, the location of temporary waste storage tanks, etc. Third, not only does DEC acknowledge that FEMA is currently updating Flood Insurance Rate Maps (FIRMs) in several high-flood areas in the state,[13]

but the Department also admits that the increased frequency and magnitude of flooding has raised a concerns regarding the reliability of the existing FIRMs in the Susquehanna and Delaware River basins.[14] Given this acknowledgment, DEC should extend this prohibition to 500-year floodplains. In general, ***no permits should be issued anywhere in the state before updated floodplain maps are in place for the entire region and these maps are reflected in DEC's environmental review and regulations***. These maps should be reflective of anticipated changes that may result from climate change, namely the increase in frequency and severity of storm events. To permit any activities before properly mapping prohibited areas is inconsistent with SEQRA.

3. **Potential changes in groundwater flow patterns.** Hydrological assumptions about groundwater flow patterns through the Marcellus and other shale formations could be altered by water demands from drilling activities, if coupled with increasingly frequent seasonal drought and/or flood periods in NY State, as climatic instability increases. More frequent alternation between periods of extreme wet and dry periods could, over time, result in changes in groundwater flow patterns[15] and unanticipated movement of production fluids and other groundwater in subsurface fractures and fissures. While challenging to predict, such migration could threaten drinking water supplies. Subsurface hydrological modeling studies have been undertaken to account for some of these climate change effects,[16] yet such studies were ignored by the RDSGEIS. ***No permits to drill near groundwater resources should be issued until climate change-based subsurface hydrological modeling studies have been incorporated into the DEC's review and regulations***.

4. **Changing seasonal precipitation patterns.** Increasing temperatures have already caused spring snowmelt to occur earlier in the year, and climate change will continue to bring changing patterns of seasonal precipitation across the state, with more annual precipitation falling as rain rather than snowfall.[17] This could affect the frequency, intensity and timing of overland flooding events at drill pad sites. In 2011, Hurricane Irene caused extensive flooding across the Catskills and upstate NY, in part because the soils were already so saturated from record-breaking heavy precipitation during the summer. As the USGCRP 2009 report attests, "…water-saturated soils can generate floods with only moderate additional precipitation."[18] In addition to prohibiting water withdrawals during low stream flow, ***the RDSGEIS should explicitly address shifting precipitation patterns resulting from climate change, increased flooding risks, and the public health issues they may create***.

5. **Increasing temperatures could exacerbate chemical volatilization and fugitive emissions from drill sites.** Ambient temperatures are projected to increase across NY State, due to the warming climate.[19] Volatilization of fracking chemicals and fugitive emissions may increase due to higher evaporation rates from higher temperatures. Exposures to workers and the community could increase, exacerbating associated health risks. ***Adverse human health impacts resulting from increased volatilization of fracking chemicals and fugitive emissions should be explicitly addressed in the RDSGEIS.***

6. **Conflicting demands on water use during drought periods are likely to be exacerbated by climate change.** Hydrofracking operations will require enormous quantities of water in drilling, in operations, and as wastewaters are disposed of. Marcellus development is projected over a thirty-year life cycle.[20] The average year would see 1,600 or more wells.[21] The amount of water consumed in each well is projected between 2.4 and 7.8 million gallons,[22] and the average well consumes 4.2 million gallons of water.[23] Based on these numbers, approximately 201,600,000,000 gallons of freshwater will be permanently removed from New York State surface and groundwater sources for the purpose of HVHF operations. The effect of these freshwater diversions in light of predicted climate change impacts to water supplies was not analyzed in the RDSGEIS. Because climate change is likely to disrupt the timing of precipitation's seasonality, the enormous water demands from hydrofracking operations could periodically conflict, during periods of local drought, with those of populations who rely on local surface and groundwater sources for drinking, domestic, municipal, business and agricultural uses. ***The potential for conflicts between HVHF operators and the public over dwindling water supplies resulting from climate change, including the adverse environmental and human health impacts associated with unprecedented freshwater diversions, should be examined in the RDSGEIS, and operators should be prohibited from consuming water from underground, surface, and municipal sources if doing so would exacerbate local drought conditions.***

7. **Nitrous oxide is an extremely potent GHG that the RDSGEIS fails to properly analyze.** Even in its current discussion of greenhouse gases (GHG) generated during drilling operations, the RDSGEIS lacks sufficient information in Sec. 6.6.2 about nitrous oxide (N_2O) as a greenhouse gas (GHG) of concern. The RDSGEIS states that because N_2O is produced in small quantities it need not be explicitly discussed in terms of its treatment or disposal.[24] However, N_2O has a global warming potential 289 times greater than carbon dioxide (CO_2), and an atmospheric lifetime 114 times longer than CO_2.[25] It is injudicious to entirely negate N_2O's effect on climate change in the RDGEIS without fuller discussion of the volumes that would be generated, from what sources, and potential treatment methods. ***The RDSGEIS should identify the impacts associated with N_2O emissions and proposed mitigation measures to curb these emissions.***

8. **Public health impacts.**. Climate change impacts can jeopardize the safety of drilling operations and exacerbate the consequences of HVHF operations on New York State, leading to adverse environmental human health impacts. ***DEC should conduct a comprehensive Health Impact Assessment (HIA) as part of the state's environmental review*** in order to evaluate potential risks to human health from gas development in New York, including the dynamic between HVHF operations (impacts on water quantity and quality, waste runoff, air pollution, etc.) and climate change (water shortages, floods, temperature rise, etc.). ***To assist in the review of comments received, at least one Public Health professional should sit on the team who evaluates the comments received by DEC on the RDGEIS***. Their expertise would be helpful in assessing other potential areas of significant health concern, ranging from air quality, water quality, worker exposure, waste management, etc...

Based on the foregoing, the RDSGEIS is incomplete in its current form. The RDSGEIS is deficient because it does not ever come to grips with the challenges to safe HVHF operations posed by climate change: it does not consider changes in the frequency of extreme rainfall events, changes in floodplain location, changes in groundwater flow patterns, changes in seasonal precipitation patterns, changes in average temperature, potential water use conflicts, the effects of nitrous oxide on climate change, or the public health impacts of climate change in association with HVHF operations. The RDSGEIS fails to include current information relevant to climate change's potential effects on New York State, which will pose potentially significant adverse environmental and public health threats in conjunction with HVHF operations that should be identified and mitigated to the maximum extent possible.

Thank you for consideration of these comments.

Respectfully,

Kim Knowlton, DrPH
Senior Scientist, Health and Environment Program
Natural Resources Defense Council
40 West 20th Street, 11th floor
New York, NY 10011-4231
(212) 727-2700 x4579 (telephone); (212) 727-1773 (fax)

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[1] Global Climate Change Impacts in the United States, Thomas R. Karl, Jerry M. Melillo, and Thomas C. Peterson (eds.). US Global Change Research Program (USGCRP), Cambridge University Press, 2009, p.32.

[2] Madsen T, Figdor E. 2007. When It Rains, It Pours: Global Warming and the Rising Frequency of Extreme Precipitation in the United States. Environment America's Research & Policy Center (December 2007).

[3] IPCC Summary for Policymakers of the Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation (SREX), Nov. 18, 2011. Available at: www.srex.org and www.ipcc.ch.

[4] New York City Panel on Climate Change (NPCC). 2009. Climate Risk Information. Available at: http://www.nyc.gov/html/om/pdf/2009/NPCC_CRI.pdf.

[5] New York State Climate Action Council's Nov. 2010 *Climate Action Plan Interim Report*, Executive Summary, pp.4-5.

[6] USGCRP (2009).

[7] Rosenzweig C, Solecki W, DeGaetano A, O'Grady M, Hassol S, Grabhorn P (Eds.). 2011. *Responding to Climate Change in New York State: The ClimAID Integrated Assessment for Effective Climate Change Adaptation. Technical Report.* (Ch.1, p.16). New York State Energy Research and Development Authority (NYSERDA), Albany, New York. Available at: www.nyserda.ny.gov.

[8] ClimAID Report (2011), p.81 sec. 4.2.2.

[9] Nov. 2010 *Climate Action Plan Interim* Nov. 2010 Report, Overview, p.10.

[10] NY State Climate Action Council, 2010. Climate Action Interim Report, Overview, pp.10, 43, and 48.

[11] Cooney CM 2012. Downscaling Climate Models: Sharpening the Focus on Local-Level Changes. *Environ Health Perspect* 120:a22-a28. http://dx.doi.org/10.1289/ehp.120-a22.

[12] 2011 RDSGEIS, Additional Precautionary Measures, Section 1.8, p. 1-18.

[13] 2011 RDSGEIS, Flood Zone Mapping, Section 2.4.9.2, p. 2-33.

[14] *Id*.

[15] USGRCP (2009), Water sector report, pp. 46-47.

[16] Goderniaux P, Brouyere S, Fowler HJ, et al. 2009. Large scale surface-subsurface hydrological model to assess climate change impacts on groundwater reserves. *Journal of Hydrology* 373:122-138.

[17] ClimAID (2011), Sec. 4.2.1, p.81.

[18] USGCRP (2009), Water Sector report, p.45.

[19] ClimAID (2011), Ch.1, pp.30-36.

[20] 2011 RDSGEIS, Cumulative Water Withdrawal Impacts, 6.1.1.7, p. 6-6.

[21] 2011 RDSGEIS, Description of Proposed Action, Chapter 2, p. 2-1.

[22] 2011 RDSGEIS, Hydraulic Fracturing Procedure, 5.9, p. 5-93.

[23] 2011 RDSGEIS, Cumulative Water Withdrawal Impacts, 6.1.1.7, p. 6-10.

[24] 2011 RDSGEIS, Emissions from Oil and Gas Operations, 6.6.2, p. 6-188.

[25] 2007 Intergovernmental Panel on Climate Change (IPCC), Fourth Assessment Report (AR4), Working Group 1 Technical Summary, Chapter 2, p.212, "Changes in Atmospheric Constituents and Radiative Forcings."

Attachment 10

Gina Solomon, M.D., M.P.H

MEMORANDUM

TO: Kate Sinding
FROM: Gina Solomon, M.D., M.P.H., Senior Scientist, NRDC; Clinical Professor of Health Sciences, UCSF
DATE: January 9, 2011
RE: NRDC Comments on RDSGEIS, NY Marcellus Shale Natural Gas Hydraulic Fracturing relative to Public Health concerns and Health Impact Assessments

Numerous health concerns have been associated with natural gas development using hydraulic fracturing, including air pollution, potential contamination of groundwater or surface water that may be used for drinking or recreation, toxicity of chemicals used in fracturing fluids, safety concerns such as fire or explosion, increased vehicle traffic, altered social conditions, and the health effects of noise, vibration, and light at night. The RDSGEIS addresses some aspects of a subset of these health issues, but fails by (1) omitting several important health issues entirely, (2) addressing only some aspects of other issues such as air, water quality and traffic without fully considering the health impacts in those areas (Note: this issue is addressed more fully in comments on those sections of the RDSGEIS submitted as part of this package), and (3) failing to consider health issues as a group in a formal Health Impact Assessment (HIA), including the interactive effects on the health of local residents and communities.

The failure to conduct a full HIA as part of the RDSGEIS is an important omission because the health effects of numerous chemicals used and emitted in the course of natural gas development have been well-described.[1] In addition, there are already numerous reports of health complaints among people who live near natural gas drilling and fracturing operations in other states. These health complaints have received coverage in the media,[2] and some cases have been investigated by researchers or government agencies.[3] Reported health issues in residents near natural gas drilling operations include: eye irritation, dizziness, nasal and throat irritation, sinus disorders, bronchitis and other respiratory symptoms, depression, nausea, fatigue, headaches, anxiety, difficulty concentrating, and a range of other symptoms.[4] Just last week, the nation's top environmental health expert

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[1] Colborn, T.; Kwiatkowski, C.; Schultz, K., and Bachran, M. Natural gas operations from a public health perspective. Human & Ecological Risk Assessment. 2011; 17(5):1039-1056. http://www.endocrinedisruption.com/chemicals.journalarticle.php. Accessed January 9, 2011; Witter R, Stinson K, Sackett H, et al. Potential Exposure-Related Human Health Effects of Oil and Gas Development: A White Paper. University of Colorado Denver, Colorado School of Public Health, Denver, Colorado, September 15, 2008. Witter R, Stinson K, Sackett H, et al. Potential Exposure-Related Human Health Effects of Oil and Gas Development: A Literature Review (2003-2008) University of Colorado Denver, Colorado School of Public Health, Denver, Colorado, August 1, 2008. http://docs.nrdc.org/health/hea_08091702.asp. Accessed January 9, 2011.
[2] See eg. ProPublica. Science Lags as Health Problems Emerge Near Gas Fields. http://www.propublica.org/article/science-lags-as-health-problems-emerge-near-gas-fields/single. Accessed January 3, 2012.
[3] See eg. ATSDR Health Consultation. Garfield County. http://www.atsdr.cdc.gov/hac/pha/Garfield_County_HC_3-13-08/Garfield_County_HC_3-13-08.pdf. Accessed January 3, 2012; Subra W. Health Survey Results of Current and Former DISH/Clark, Texas Residents. Earthworks, Dec 17, 2009. http://www.earthworksaction.org/library/detail/health_survey_results_of_current_and_former_dish_clark_texas_residents/. Accessed January 3, 2012.
[4] Ibid.

affirmed his view that more research is necessary regarding the impacts of natural gas drilling on human health.[5] Although much research needs to be done to investigate specific associations between the reported symptoms and nearby gas extraction operations, there is sufficient information on health issues associated with the chemicals and other environmental stressors at these sites to demand performance of a full HIA.

> *Health impact assessment is a systematic process that uses an array of data sources and analytic methods and considers input from stakeholders to determine the potential effects of a proposed policy, plan, program, or project on the health of a population and the distribution of those effects within the population. Health impact assessment provides recommendations on monitoring and managing those effects.*
>
> National Research Council, 2011

Rationale for a Health Impact Assessment in New York State

In September 2011, the National Research Council of the National Academies of Science (NAS) issued a report entitled: *Improving Health in the United States: The Role of Health Impact Assessment*. The report recommended the greater use of HIA in decision making in the United States, saying that: "systematic assessment of the health consequences of policies, programs, plans, and projects is critically important for protecting and promoting public health; as indicated, lack of assessment can have many unexpected adverse health (and economic) consequences."[6]

According to the Centers for Disease Control and Prevention (CDC), the HIA framework is used to bring potential public health impacts and considerations to the decision-making process for plans, projects, and policies that fall outside of traditional public health arenas, such as transportation and land use.[7] The National Environmental Policy Act (NEPA) requires federal agencies to consider the environmental impact of their proposed actions on social, cultural, economic, and natural resources prior to implementation. In New York, the State Environmental Quality Review Act (SEQRA) regulations [see 617.2(l)] define Environment as: "…the physical conditions that will be affected by a proposed action, including land, air, water, minerals, flora, fauna, noise, resources of agricultural, archeological, historic or aesthetic significance, existing patterns of population concentration, distribution or growth, existing community or neighborhood character, and *human health*" (emphasis added).[8]

In the United States, HIA is a rapidly emerging practice. HIA is also regularly performed in Europe and Canada. Some countries have mandated HIA as part of a regulatory process. In the U.S., some version of an HIA is arguably required by NEPA and by many state "mini-NEPAs,"[9] including most explicitly, the New York SEQRA,

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[5] CDC scientist: tests needed on gas drilling impact. Associated Press. January 4, 2012. http://online.wsj.com/article/AP8338b702930849f49d22a5d96b7d1b2d.html. Accessed January 5, 2012.
[6] National Research Council. Improving Health in the United States: The Role of Health Impact Assessment. Washington, DC: The National Academies Press, 2011, pp. 4-5.
[7] Centers for Disease Control and Prevention. http://www.cdc.gov/healthyplaces/hia.htm. Accessed January 3, 2012.
[8] See also Environmental Conservation Law § 8-0103(5) ("…it is the intent of the legislature that the government of the state take immediate steps to identify any critical thresholds for the health and safety of the people of the state and take all coordinated actions necessary to prevent such thresholds from being reached).
[9] Bhatia, R and Wernham, A. Integrating Human Health into Environmental Impact Assessment: An Unrealized Opportunity for Environmental Health and Justice. Environmental Health Perspectives. 2008;116(8): 991-1000.

which clearly specifies the mandate for a full characterization of the effects on human health. The National Academies of Science committee on HIA recommended: "improving the integration of health into EIA under NEPA and related state laws…[to] serve the mission of public health and the goals of HIA….[In order t]o ensure reasonable priority of health issues under NEPA, public-health agencies should be afforded a substantive role in the scoping and oversight of health-effects analysis in EIA, and health-effects analysis must be afforded resources commensurate with the task.[10]

There is precedent for performing formal HIAs for drilling activities. In 2007, an HIA of proposed oil and gas development projects in Alaska's North Slope was performed by the local government.[11] The HIA evaluated predicted impacts on fish and wildlife and the consequences for diet and health in the local population. It also identified potential social changes such as drug and alcohol use. The HIA led to new requirements for air quality analysis and monitoring of any oil-related contaminants in subsistence foods, and to a new requirement for worker education on drugs, alcohol and sexually transmitted diseases.

A draft HIA was done in Colorado for a proposed gas drilling development in Battlement Mesa. This draft HIA identified eight major areas of health concern (stressors) associated with natural gas development and production: air emissions, water and soil contaminants, truck traffic, noise/light/vibration, health infrastructure, accidents and malfunctions, community wellness, and economics/employment.[12] Several physical health outcomes linked to potential exposures were considered, including respiratory, cardiovascular, cancer, psychiatric, and injury/motor vehicle-related impacts on vulnerable and general populations in the community. The study concluded: "The key findings of our study are that [the] health of the Battlement Mesa residents will most likely be affected by chemical exposures, accidents or emergencies resulting from industry operations and stress-related community changes."[13] The researchers went on to recommend a set of mitigation measures to reduce the health threats to local residents. Although the Battlement Mesa HIA was halted by the local Board of County Commissioners, apparently for political reasons,[14] it demonstrated the feasibility and utility of HIA for evaluating risks to the health of local residents from hydraulic fracturing and natural gas drilling operations.

In October of 2011, hundreds of health professionals signed a letter to Governor Cuomo specifically requesting that the draft SGEIS be "supplemented to include a full assessment of the public health impacts of gas

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[10] National Research Council. Improving Health in the United States: The Role of Health Impact Assessment. Washington, DC: The National Academies Press, 2011, p. 111-113.

[11] Wernham A. Building a Statewide Health Impact Assessment Program: A Case Study from Alaska. Northwest Public Health. Fall/Winter 2009; Health Impact Project. Case Study: Oil Development of Alaska's North Slope. http://www.healthimpactproject.org/resources/case-study-oil-development-of-alaskas-north-slope. Accessed January 5, 2011.

[12] Witter R, McKenzie L, Towle M, et al. Health Impact Assessment for Battlement Mesa, Garfield County Colorado. Colorado School of Public Health, University of Colorado, Denver, September 2010. http://www.garfield-county.com/public-health/documents/1%20%20%20Complete%20HIA%20without%20Appendix%20D.pdf. Accessed January 4, 2012.

[13] Battlement Mesa Health Impact Assessment (2nd Draft). March 1, 2011. http://www.garfield-county.com/public-health/battlement-mesa-health-impact-assessment-draft2.aspx. Accessed January 4, 2012.

[14] Vote Ends work on Battlement Mesa HIA. May 4, 2011. http://www.healthimpactproject.org/news/in/vote-ends-work-on-battlement-mesa-hia. Accessed January 4, 2012.

exploration and production."[15] The letter pointed out that, "there is a growing body of evidence on health impacts from industrial gas development," and specifically stated that: "A comprehensive Health Impact Assessment (HIA) would be the most appropriate mechanism for this work." The Director of the Agency for Toxic Substances and Disease Registry (ATSDR), Dr. Christopher Portier, also supports more thorough assessment of the health impacts of gas drilling, stating: "Studies should include all the ways people can be exposed, such as through air, water, soil, plants and animals."[16]

In summary, the requirements of SEQRA and recommendations of the National Academies of Science argue strongly for the need for a New York HIA of the health impacts of gas drilling and hydraulic fracturing. A similar investigation in Colorado revealed a set of potentially significant human health impacts associated with chemical exposures, accidents, and stress-related community changes, all of which were insufficiently considered in the New York RDSGEIS. Without a full assessment and mitigation of the impacts of the risks, the health of New York State residents and communities is likely to suffer.

[15] Abramson A, Abrams J, Alexander M, et al. Letter to The Honorable Andrew M. Cuomo. October 5, 2011. http://www.psehealthyenergy.org/resources/view/198813. Accessed January 5, 2012.
[16] CDC scientist: tests needed on gas drilling impact. Associated Press. January 4, 2012. http://online.wsj.com/article/AP8338b702930849f49d22a5d96b7d1b2d.html. Accessed January 5, 2012.

Attachment 11

Briana Mordick

January 10, 2012

To: Kate Sinding

From: Briana Mordick

Subject: Technical analysis of hydraulic fracturing-induced seismicity provisions in the New York State Revised Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program

Introduction

The following report is a technical review and analysis of the hydraulic fracturing-induced seismicity provisions of the New York State (NYS) 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. This report includes recommendations for properly managing the risks associated with induced seismicity.

Analysis

The RDSGEIS fails to require operators of HVHF wells to consider the risk of induced seismicity when siting wells and designing hydraulic fracture treatments, concluding that,

"There is a reasonable base of knowledge and experience related to seismicity induced by hydraulic fracturing. Information reviewed indicates that there is essentially no increased risk to the public, infrastructure, or natural resources from induced seismicity related to hydraulic fracturing. The microseisms created by hydraulic fracturing are too small to be felt, or to cause damage at the ground surface or to nearby wells. Accordingly, no significant adverse impacts from induced seismicity are expected to result from high-volume hydraulic fracturing operations."[1]

Since the RDSGEIS was written, hydraulic fracturing has been confirmed to have caused induced seismicity strong enough to be felt at the surface. In a report commissioned by United Kingdom-based Cuadrilla Resources, researchers concluded that a series of earthquakes in Lancashire, UK were likely caused by hydraulic fracturing. Two relatively large earthquakes, with magnitudes 2.3 and 1.5, and 48 smaller events occurred in the hours after several stages of the Preese Hall 1 well were fracked.[2] A separate report written by a seismologist at the Oklahoma Geological Survey concluded that a swarm of about 50 earthquakes in Garvin County, Oklahoma, ranging in magnitude from 1.0 to 2.8, could also have been induced by hydraulic fracturing.[3]

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[1] Revised Draft SGEIS 2011, Executive Summary, Page 19

[2] de Pater, C.J., and Baisch, S., 2011, *Geomechanical Study of Bowland Shale Seismicity: Synthesis Report*, prepared for Cuadrilla Resources Ltd, 71p., available at: http://www.cuadrillaresources.com/cms/wp-content/uploads/2011/12/Final_Report_Bowland_Seismicity_02-11-11.pdf

[3] Holland, A., 2011, *Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma*, Oklahoma Geological Survey, Open-File Report OF1-2011, 31p., available at: http://www.ogs.ou.edu/pubsscanned/openfile/OF1_2011.pdf

The RDSGEIS concedes that, "There are no seismic monitoring protocols or criteria established by regulatory agencies that are specific to high volume hydraulic fracturing,"[4] and recognizes that, "It is important to avoid injecting fluids into known, significant, mapped faults when hydraulic fracturing."[5] However, instead of developing such protocols and requiring operators to demonstrate that they have accounted for seismic risks in the siting of wells and design of hydraulic fracture treatments, the RSDGEIS assumes that, "Generally, operators would avoid faults because they disrupt the pressure and stress field and the hydraulic fracturing process,"[6] and, "It is in the operator's best interest to closely control the hydraulic fracturing process to ensure that fractures are propagated in the desired direction and distance and to minimize the materials and costs associated with the process."[7]

To justify why no additional analysis or monitoring is required to prevent induced seismicity, the RDSGEIS states, "The routine microseismic monitoring that is performed during hydraulic fracturing serves to evaluate, guide, and control the process and is important in optimizing well treatments,"[8] and, "Monitoring beyond that which is typical for hydraulic fracturing does not appear to be warranted, based on the negligible risk posed by the process and very low seismic magnitude."[9] However, earlier in the document, NYSERDA's consultant ICF International concludes that, "…fracture monitoring by [microseismic fracture mapping] is **not regularly used** because of cost…"[10] So in fact, seismic monitoring would rarely be employed during a routine hydraulic fracture treatment.

The RDSGEIS further assumes that no additional analysis of seismic risk is needed due to the fact that, "The locations of major faults in New York have been mapped (Figure 4.13) and few major or seismically active faults exist within the fairways for the Marcellus and Utica Shales."[11] There are two fatal flaws with this assumption. First, in both the UK and Oklahoma incidents, the earthquakes likely occurred due to slippage on minor, sub-seismic faults. Therefore, knowing the locations of only "major faults" is not sufficient to assess the potential risk of induced seismicity from hydraulic fracturing. Second, it is precisely the injection of fluids which induces previously inactive faults to become active. Therefore, whether a fault is currently or even recently seismically active is not sufficient to predict whether it could become active due to human activity – the definition of induced seismicity. A paper on earthquake hazards from deep well injection prepared by the U.S. Geological Survey for the U.S. Environmental Protection Agency concludes that predicting and mitigating seismic hazard risks in the Eastern United States is particularly problematic, as the causes of natural earthquakes and location of faults are not well understood.[12]

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[4] Revised Draft SGEIS 2011, Page 6-322
[5] Id.
[6] Id.
[7] Revised Draft SGEIS 2011, Page 6-323
[8] Revised Draft SGEIS 2011, Page 6-323
[9] Revised Draft SGEIS 2011, Page 6-328
[10] Revised Draft SGEIS 2011, Page 5-88, emphasis added
[11] Revised Draft SGEIS 2011, Page 6-327
[12] Nicholson, C., and Wesson, R., 1990, *Earthquake Hazard Associated With Deep Well Injection – A Report to the U.S. Environmental Protection Agency*, U.S. Geological Survey Bulletin 1951, 86p., available at: http://pubs.usgs.gov/bul/1951/report.pdf

Induced seismicity could result in unwanted and dangerous consequences, depending on the size and location of the earthquake. Fault movement may potentially endanger groundwater by creating or enhancing migration pathways between the zone being hydraulically fractured and underground sources of drinking water. Seismicity can also compromise wellbore integrity. The induced seismicity event in the UK caused ovalization of the production casing over hundreds of feet, with more than a half-inch of ovalization occurring over an approximately 250 foot length.[13] Such damage could compromise the cement bond, allowing methane or fluids to migrate up the back side of the casing to groundwater.

Even a relatively small earthquake could cause damage over a large area. The USGS report cited above states that, "Earthquakes in the Central and the Eastern United States typically cause damage over much larger areas as compared to earthquakes of the same size in the Western United States. This is primarily the result of the lower attenuation of seismic waves in the East versus the West, but other factors also may be involved."[14] Earthquakes could cause property damage including to private homes and public buildings and could also put at risk the aqueducts, tunnels, and infrastructure that deliver the New York City drinking water supply. In a report prepared for the New York City Department of Environmental Protection, environmental engineering firm Hazen and Sawyer concluded that, "…liner cracks can be anticipated to develop as the tunnels age, due to normal geologic activity (e.g., seismic activity), and to changes in subsurface conditions associated with widespread hydrofracturing, gas reservoir depletion/withdrawal and injection well operation," and, "Detrimental effects [to tunnel liners] could include liner cracks, which would facilitate infiltration of pressurized fluids."[15] In addition to natural seismic activity, induced seismicity could also be expected to create additional liner cracks. The authors also concluded that, "Hydraulic fracturing operations in proximity to the naturally occurring fracture systems that intersect DEP tunnels will increase the risk of (a) contaminating drinking water with drilling and fracturing chemicals and poor quality formation water; (b) methane accumulation around and within DEP subsurface infrastructure; and (c) tunnel liner structural failure. Mitigation of risks to drinking water quality and infrastructure integrity will require revision of current setback provisions to reflect the occurrence of laterally extensive subsurface faults, fractures, and brittle structures."[16] If earthquakes are induced along faults that intersect the DEP tunnels, these risks could be further exacerbated.

Even in the absence of actual damage, induced seismic events will have financial and manpower costs associated with the investigation of the causes and effects of the earthquake and from the suspension of operations until such studies are completed.

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[13] Id. at 2
[14] Id. at 13
[15] Hazen and Sawyer, 2009, *Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed: Final Impact Assessment Report,* prepared for New York City Department of Environmental Protection, 100p., available at:
http://www.nyc.gov/html/dep/pdf/natural_gas_drilling/12_23_2009_final_assessment_report.pdf
[16] Id., Appendix D

The RDSGEIS provides insufficient analysis and scientific evidence to support its conclusion that regulations to reduce the risk of induced seismicity from hydraulic fracturing are not necessary.

Recommendation

The RDSGEIS should require operators to provide a site-specific analysis of the risk of induced seismicity due to hydraulic fracturing. This should include a detailed analysis of the geology, including the locations of known faults and an assessment of the seismic history of the region. Operators should be required to provide an analysis detailing the maximum magnitude of an earthquake that could be triggered based on anticipated injection volume and the probability that such an earthquake may occur based on site-specific geologic and geophysical parameters such as fault and fracture density, lithology, minimum horizontal stress, and anticipated pore pressure as a result of fluid injection.[17] Operators should then be required to use this data to properly design their hydraulic fracture treatment to reduce the risk of triggering induced seismicity. Operators should be required to perform seismic monitoring during hydraulic fracturing to ensure that any seismicity that occurs is within design parameters.

[17] See, e.g., Shapiro,S. A., C. Dinske, and J. Kummerow (2007), Probability of a given magnitude earthquake induced by a fluid injection, Geophys. Res. Lett., 34, L22314, doi:10.1029/2007GL031615.

Attachment 12

Expert Resumes

Harvey Consulting, LLC.

- Susan Harvey

Tom Myers, Ph.D.

Glenn Miller, Ph.D.

Ralph Seiler, Ph.D.

Meliora Design, LLC.

- Michele Adams, P.E.
- Ruth Sitler, P.E.

The Louis Berger Group, Inc.

- Niek Veraart, AICP, ASLA
- Raed EL-Farhan, Ph.D.
- Hope Luhman, Ph.D., RPA
- Edward Samanns, PWS, CE
- Leo Tidd
- Dane Ismart

Kevin Heatley

Kim Knowlton, DrPH

Gina Solomon, M.D.

Briana Mordick

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

Susan L. Harvey, Owner

Susan Harvey has 25 years of experience as a Petroleum and Environmental Engineer, working on oil and gas exploration and development projects. Ms. Harvey is the owner of Harvey Consulting, LLC, a consulting firm providing oil and gas, environmental, regulatory compliance advice and training to clients. Ms. Harvey held engineering and supervisory positions at both Arco and BP including Prudhoe Bay Engineering Manager and Exploration Manager. Ms. Harvey has planned, engineered, executed and managed both on and offshore exploration and production operations, and has been involved in the drilling, completion, stimulation, testing and oversight of hundreds of wells in her career. Ms. Harvey's experience also includes air and water pollution abatement design and execution, best management practices, environmental assessment of oil and gas project impacts, and oil spill prevention and response planning. During Governor Knowles Administration, Ms. Harvey headed the Industry Preparedness Program for the Alaska Department of Environmental Conservation, Division of Spill Prevention and Response; she was responsible for oil spill prevention and response oversight of all Alaska industry operations that produce, store or transport hydrocarbons. Ms. Harvey taught air pollution control engineering courses at the University of Alaska in the Graduate Engineering Program.

Education Summary:

Environmental Engineering
Masters of Science
University of Alaska Anchorage

Petroleum Engineering
Bachelor of Science
University of Alaska Fairbanks

Consulting Services:

- Oil and gas, environmental, regulatory compliance advice and training
- Oil spill prevention and response planning
- Air pollution assessment and control

Employment Summary:

2002-Current	Harvey Consulting, LLC., Owner
2005-Current	Harvey Fishing, LLC., Co-owner
2002-2007	University of Alaska at Anchorage Environmental Engineering Graduate Level, Adjunct Professor
1999-2002	State of Alaska, Department of Environmental Conservation Environmental Supervisory Position
1996-1999	Arco Alaska Inc. Engineering and Supervisory Positions held
1989-1996	BP Exploration (Alaska), Inc. Environmental, Engineering, and Supervisory Positions held
1987-1989	Standard Oil Production Company *(purchased by BP in 1989)*, Engineering Position
1985-1986	Conoco, Production Engineer and New Mexico Institute of Mining and Technology Petroleum Research & Recovery Center, Laboratory Research Assistant

Harvey Consulting, LLC
PO Box 771026 Eagle River, Alaska 99577
Email:sharvey@mtaonline.net; Phone: (907) 694-7994; Fax: (907) 694-7995

Employment Detail:

2002-Current **Harvey Consulting, LLC.**
Owner of consulting business providing oil and gas, environmental, regulatory compliance and training to clients.

2005-Current **Harvey Fishing, LLC.**
Co-owner and operator of a commercial salmon fishing business in Prince William Sound Alaska.

2002-2007 **University of Alaska at Anchorage**
Environmental Engineering Graduate Level Program, Adjunct Professor Air Pollution Control.

1999-2002 **State of Alaska, Department of Environmental Conservation**
Environmental Supervisory Position
Industry Preparedness and Pipeline Program Manager, Alaska Department of Environmental Conservation, Division of Spill Prevention and Response. Managed 30 staff in four remote offices. Main responsibility was to ensure all regulated facilities and vessels across Alaska submitted high quality Oil Discharge Prevention and Contingency Plans to prevent and respond to oil spills. Staff included field and drill inspectors, engineers, and scientists. Managed all required compliance and enforcement actions.

1996-1999 **Arco Alaska Inc.**
Engineering and Supervisory Positions held
Prudhoe Bay Waterflood and Enhanced Oil Recovery Engineering Supervisor. Main responsibility was to set the direction for a team of engineers to design, optimize and manage the production over 120,000 barrels of oil per day from approximately 400 wells and nine drill sites, from the largest oil field in North America. Responsible for six concurrently operating drilling and workover rigs.

Prudhoe Bay Satellite Exploration Engineering Supervisor for development of six new Satellites Oil Fields. Main responsibility was to set the direction for a multidisciplinary team of Engineers, Environmental Scientists, Facility Engineers, Business Analysts, Geoscientists, Land, Tax, Legal, and Accounting. Responsible for two appraisal drilling rigs.

Lead Engineer for Arco Western Operating Area Development Coordination Team. Lead a multi-disciplinary team of engineers and geoscientists, working on the Prudhoe Bay oil field.

1989-1996 **BP Exploration (Alaska), Inc.**
Environmental, Engineering, and Supervisory Positions held
Senior Engineer Environmental & Regulatory Affairs Department. Main responsibilities included: air quality engineering, technical and permitting support for Northstar, Badami, Milne Point Facilities and Exploration Projects.

Senior Engineer/Litigation Support Manager. Duties included managing a multidisciplinary litigation staff to support the ANS Gas Royalty Litigation, Quality Bank Litigation and Tax Litigation. Main function was to coordinate, plan and organize the flow of work amongst five contract attorneys, seven in-house attorneys, two technical consultants, eight expert witnesses, four in-house consultants and twenty-two staff members.

Senior Planning Engineer. Provided technical, economic, and negotiations support on Facility, Power, Water and Communication Sharing Agreements. Responsibilities also included providing technical assistance on recycled oil issues, ballast water disposal issues, chemical treatment options, and contamination issues.

Production Planning Engineer. Coordinated State approval of the Sag Delta North Participating Area and Oil Field. Resolved technical, legal, tax, owner and facility sharing issues. Developed an LPG feasibility study for the Endicott facility.

Reservoir Engineer. Developed, analyzed and recommended options to maximize recoverable oil reserves for the Endicott Oil Field through 3D subsurface reservoir models, which predicted fluid movements and optimal well placement for the drilling program. Other duties included on-site wellbore fluid sampling and subsequent lab analysis.

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

1987-1989 **Standard Oil Production Company, Production Engineer**
Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

Engineering Internship, Barry Waterflood Oklahoma City OK.

1986 **Conoco, Production Engineer**
Production Engineer. Engineering Internship, Hobbs New Mexico.

1985-1986 **New Mexico Institute of Mining and Technology**
Petroleum Research & Recovery Center
Laboratory Research Assistant, Enhanced Oil Recovery, Surfactant Research.

Harvey Consulting, LLC, Major Projects and Publications

Northeast Natural Energy, LLC. and Enrout Properties, LLC vs. The City of Morgantown, West Virginia, technical support to The City of Morgantown, 2011.

Arctic Oil and Gas Project, technical support to Pew Charitable Trust, 2010-2011.

Stockport Mountain Corporation, LLC vs. Norcross Wildlife Foundation, Inc., technical support to Norcross Wildlife Foundation, Inc., 2011.

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Tom Myers, Ph.D.
Consultant, Hydrology and Water Resources
6320 Walnut Creek Road
Reno, NV 89523
(775) 530-1483
Tom_myers@charter.net

Curriculum Vitae

Objective: To provide diverse research and consulting services to nonprofit, government, legal and industry clients focusing on groundwater modeling, hydrogeology, environmental forensics and compliance, NEPA analysis, federal and state regulatory review, fluvial morphology and environmental and water policy.

Education

Years	Degree	University
1992-96	Ph.D. Hydrology/Hydrogeology	University of Nevada, Reno Dissertation: Stochastic Structure of Rangeland Streams
1990-92		University of Arizona, Tucson AZ Classes in pursuit of Ph.D. in Hydrology.
1988-90	M.S. Hydrology/Hydrogeology	University of Nevada, Reno Thesis: Stream Morphology, Stability and Habitat in Northern Nevada
1981-83		University of Colorado, Denver, CO Graduate level water resources engineering classes.
1977-81	B.S., Civil Engineering	University of Colorado, Boulder, CO

Special Coursework

Years	Course	Sponsor
2011	Hydraulic Fracturing of the Marcellus Shale	National Groundwater Association
2008	Fractured Rock Analysis	MidWest Geoscience
2005	Groundwater Sampling Field Course	Nielson Environmental Field School
2004	Environmental Forensics	National Groundwater Association
2004 and -5	Groundwater and Environmental Law	National Groundwater Association

Professional Experience

Years	Position	Duties
1993-Pr.	Hydrologic Consultant	Surface, groundwater and systems modeling, hydrogeology studies, stream restoration design, watershed modeling studies and expert testimony for industry, nonprofit groups, and government agencies.
1999-2004	Great Basin Mine Watch Executive Director	Responsible for reviewing and commenting on mining projects with a focus on groundwater and surface water resources, preparing appeals and litigation, writing reports about mining, fundraising, organizational development, supervision and personnel management.
1992-1997	University of Nevada, Reno Research Associate	Research on riparian area and watershed management including stream morphology, aquatic habitat, cattle grazing and low-flow and flood hydrology.
1990-1992	University of Arizona, Tucson Research and Teaching Assistant	Research on rainfall/runoff processes and climate models. Taught lab sections for sophomore level "Principles of Hydrology". Received 1992 Outstanding Graduate Teaching Assistant Award in the College of Engineering
1988-1990	University of Nevada, Reno Research Assistant	Research on aquatic habitat, stream morphology and livestock management.
1983-1988	US Bureau of Reclamation, Boulder City, NV Hydraulic Engineer	Performed hydrology planning studies on topics including floodplains, water supply, flood control, salt balance, irrigation efficiencies, sediment transport, stream morphology, flood frequency, rainfall-runoff modeling and groundwater balances.
1981-1983	Faulkner-Kellogg and Assoc., Lakewood Co Design Engineer	Basic drainage, grading and subdivision design. Flood control studies.

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Myers, T., 2011. Rebuttal Report: Part 2, Review of Groundwater Model Submitted by Southern Nevada Authority and Comparison with the Myers Model. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T. 2011. Rebuttal Report: Part 3, Prediction of Impacts Caused by Southern Nevada Water Authority Pumping Groundwater From Distributed Pumping Options for Spring Valley, Cave Valley, Dry Lake Valley, and Delamar Valley. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T., 2011. Baseflow Selenium Transport from Phosphate Mines in the Blackfoot River Watershed Through the Wells Formation to the Blackfoot River, Prepared for the Greater Yellowstone Coalition.

Myers, T., 2011. Blackfoot River Watershed, Groundwater Selenium Loading and Remediation. Prepared for the Greater Yellowstone Coalition.

Myers, T., 2010. Planning the Colorado River in a Changing Climate, Colorado River Simulation System (CRSS) Reservoir Loss Rates in Lakes Powell and Mead and their Use in CRSS. Prepared for Glen Canyon Institute.

Myers, T., 2010. Technical Memorandum, Updated Groundwater Modeling Report, Proposed Rosemont Open Pit Mining Project. Prepared for Pima County and Pima County Regional Flood Control District

Myers, T., 2009. Monitoring Groundwater Quality Near Unconventional Methane Gas Development Projects, A Primer for Residents Concerned about Their Water. Prepared for Natural Resources Defense Council. New York, New York.

Myers, T., 2009. Technical Memorandum, Review and Analysis of the Hydrology and Groundwater and Contaminant Transport Modeling of the Draft Environmental Impact Statement Blackfoot Bridge Mine, July 2009. Prepared for Greater Yellowstone Coalition, Idaho Falls, Idaho.

Myers, T., 2008. Hydrogeology of the Carbonate Aquifer System, Nevada and Utah With Emphasize on Regional Springs and Impacts of Water Rights Development. Prepared for: Defenders of Wildlife, Washington, D.C.. June 1, 2008.

Myers, T., 2008. Hydrogeology of the Muddy River Springs Area, Impacts of Water Rights Development. Prepared for: Defenders of Wildlife, Washington, D.C. May 1, 2008

Myers, T., 2008. Hydrogeology of the Santa Rita Rosemont Project Site, Numerical Groundwater Modeling of the Conceptual Flow Model and Effects of the Construction of the Proposed Open Pit, April 2008. Prepared for: Pima County Regional Flood Control District, Tucson AZ.

Myers, T., 2008. Technical Memorandum, Review, Record of Decision, Environmental Impact Statement Smoky Canyon Mine, Panels F&G, U.S. Department of the Interior, Bureau of Land Management. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV.

Myers, T., 2007. Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Proposed Panels F and G. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV. December 11, 2007.

Myers, T., 2007. Hydrogeology, Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Documentation of a Groundwater Flow and Contaminant Transport Model. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV, December 7, 2007.

Myers, T., 2007. Review of Hydrogeology and Water Resources for the Final Environmental Impact Statement, Smoky Canyon Mine, Panels F and G and Supporting Documents. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno, NV. December 12, 2007.

Myers, T., 2007. Hydrogeology of the Powder River Basin of Southeast Montana Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council. February 12 2007.

Myers, T., 2007. Hydrogeology of the Santa Rita Rosemont Project Site, Conceptual Flow Model and Water Balance, Prepared for: Pima County Flood Control District, Tucson AZ

Myers, T., 2006. Review of Mine Dewatering on the Carlin Trend, Predictions and Reality. Prepared for Great Basin Mine Watch, Reno, NV

Myers, T., 2006. Hydrogeology of Spring Valley and Effects of Groundwater Development Proposed by the Southern Nevada Water Authority, White Pine and Lincoln County, Nevada. Prepared for Western Environmental Law Center for Water Rights Protest Hearing.

Myers, T., 2006. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs of the Pinnacle Gas Resource, Dietz Project In the Powder River Basin of Southeast Montana. Affidavit prepared for Northern Plains Resource Council, April 4 2006.

Myers, T., 2006. Review of Hydrogeology and Water Resources for the Draft Environmental Impact Statement, Smoky Canyon Mine, Panels F and G, Technical Report 2006-01-Smoky Canyon. Prepared for Natural Resources Defense Council.

Myers, T., 2006. Review of Nestle Waters North America Inc. Water Bottling Project Draft Environmental Impact Report / Environmental Assessment. Prepared for McCloud Watershed Council, McCloud CA.

Myers, T., 2005. Hydrology Report Regarding Potential Effects of Southern Nevada Water Authority's Proposed Change in the Point of Diversion of Water Rights from Tikapoo Valley South and Three Lakes Valley North to Three Lakes Valley South. Prepared for Western Environmental Law Center for Water Rights Protest Hearing

Myers, T., 2005. Review of Draft Supplemental Environmental Impact Statement, Ruby Hill Mine Expansion: East Archimedes Project NV063-EIS04-34, Technical Report 2005-05-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2005. Hydrogeology of the Powder River Basin of Southeast Montana, Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council, Billings, MT in support of pending litigation.

Myers, T., 2005. Nevada State Environmental Commission Appeal Hearing, Water Pollution Control Permit

Renewal NEV0087001, Big Springs Mine. Expert Report. Prepared for Great Basin Mine Watch, Reno NV.

Myers, T., 2005. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs In the Powder River Basin of Southeast Montana. Prepared for Northern Plains Resource Council, Billings, MT.

Myers, T., 2004. An Assessment of Contaminant Transport, Sunset Hills Subdivision and the Anaconda Yerington Copper Mine, Technical Report 2004-01-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Memorandum: Pipeline Infiltration Project Groundwater Contamination. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Report Seepage From Waste Rock Dump to Surface Water The Jerritt Canyon Mine, Technical Report 2004-03-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2001. An Assessment of Diversions and Water Rights: Smith and Mason Valleys, NV. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrogeology of the Basin Fill Aquifer in Mason Valley, Nevada: Effects of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrology and Water Balance, Smith Valley, NV: Impacts of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV

Myers, T., 2000. Alternative Modeling of the Gold Quarry Mine, Documentation of the Model, Comparison of Mitigation Scenarios, and Analysis of Assumptions. Prepared for Great Basin Mine Watch. Center for Science in Public Participation, Bozeman MT.

Myers, T., 2000. Environmental and Economic Impacts of Mining in Eureka County. Prepared for the Dept. Of Applied Statistics and Economics, University of Nevada, Reno.

Myers, T., 1999. Water Balance of Lake Powell, An Assessment of Groundwater Seepage and Evaporation. Prepared for the Glen Canyon Institute, Salt Lake City, UT.

Myers, T., 1998. Hydrogeology of the Humboldt River: Impacts of Open-pit Mine Dewatering and Pit Lake Formation. Prepared for Great Basin Mine Watch, Reno, NV.

Peer-Reviewed Publications

Myers, T., in review. Potential contaminant pathways from hydraulically fractured shale to aquifers. *Ground Water*.

Myers, T., 2009. Groundwater management and coal-bed methane development in the Powder River Basin of Montana. *J Hydrology* 368:178-193.

Myers, T.J. and S. Swanson, 1997. Variation of pool properties with stream type and ungulate damage in central Nevada, USA. *Journal of Hydrology* 201-62-81

Myers, T.J. and S. Swanson, 1997. Precision of channel width and pool area measurements. *Journal of the*

American Water Resources Association 33:647-659.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of pool-to-pool structure in small Nevada rangeland streams. *Water Resources Research* 33(4):877-889.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of transect-to-transect properties of Great Basin rangeland streams. *Water Resources Research* 33(4):853-864.

Myers, T.J. and S. Swanson, 1996. Long-term aquatic habitat restoration: Mahogany Creek, NV as a case study. *Water Resources Bulletin* 32:241-252

Myers, T.J. and S. Swanson, 1996. Temporal and geomorphic variations of stream stability and morphology: Mahogany Creek, NV. *Water Resources Bulletin* 32:253-265.

Myers, T.J. and S. Swanson, 1996. Stream morphologic impact of and recovery from major flooding in north-central Nevada. *Physical Geography* 17:431-445.

Myers, T.J. and S. Swanson, 1995. Impact of deferred rotation grazing on stream characteristics in Central Nevada: A case study. *North American Journal of Fisheries Management* 15:428-439.

Myers, T.J. and S. Swanson, 1992. Variation of stream stability with stream type and livestock bank damage in northern Nevada. *Water Resources Bulletin* 28:743-754.

Myers, T.J. and S. Swanson, 1992. Aquatic habitat condition index, stream type, and livestock bank damage in northern Nevada. *Water Resources Bulletin* 27:667-677.

Zonge, K.L., S. Swanson, and T. Myers, 1996. Drought year changes in streambank profiles on incised streams in the Sierra Nevada Mountains. *Geomorphology* 15:47-56.

Selected Abstracts, Magazine and Proceedings Articles

Myers, T., 2006. Modeling Coal Bed Methane Well Pumpage with a MODFLOW DRAIN Boundary. In MODFLOW and More 2006 Managing Ground Water Systems, Proceedings. International Groundwater Modeling Center, Golden CO. May 21-24, 2006.

Myers, T., 2006. Proceed Carefully: Much Remains Unknown, *Southwest Hydrology 5(3)*, May/June 2006, pages 14-16.

Myers, T., 2004. Monitoring Well Screening and the Determination of Groundwater Degradation, Annual Meeting of the Nevada Water Resources Association, Mesquite, NV. February 27-28, 2004.

Myers, T., 2001. Impacts of the conceptual model of mine dewatering pumpage on predicted fluxes and drawdown. In MODFLOW 2001 and Other Modeling Odysseys, Proceedings, Volume 1. September 11-14, 2001. International Ground Water Modeling Center, Golden, Colorado.

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Kendall, D.R. (ed.), Conjunctive Use of Water Resources: Aquifer Storage and Recovery. AWRA Symposium, Long Beach California. October 19-23, 1997

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Life in a Closed Basin, Nevada Water Resources Association, October 8-10, 1997, Elko, NV.

Myers, T., 1997. Uncertainties in the hydrologic modeling of pit lake refill. American Chemical Society Annual Meeting, Las Vegas, NV, Sept. 8-12, 1997.

Myers, T., 1997. Use of Groundwater modeling and geographic information systems in water marketing. In Warwick, J.J. (ed.), Water Resources Education, Training, and Practice: Opportunities for the Next Century. AWRA Symposium, Keystone, Colo. June 29-July 3, 1997.

Myers, T., 1995. Decreased surface water flows due to alluvial pumping in the Walker River valley. Annual Meeting of the Nevada Water Resources Association, Reno, NV, March 14-15, 1995.*

Select Testimony in Litigation and Administrative Hearings

Northeast Natural Energy LLC v. City of Morgantown, Monongalia Circuit Court, Civil Action No. 11-C-411. 2011. Submitted to Deposition. Case dismissed on constitutional grounds.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 53987-53992, 54003-54021. September 26 through November 14, 2011, Spring Valley, Cave Valley, Dry Lake and Delamar Valley. Testimony on behalf of protestants Great Basin Water Network, Confederated Tribes of the Goshute Reservation.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 53987-53992, Cave Valley, Dry Lake, and Delamar Valley, NV. February 4 through February 14, 2008. Testimony on behalf of protestant Great Basin Water Network.

Cole et al v. J.M.Huber Corp. and William DeLapp. U.S. District Court for the District of Wyoming. Case No. 06-CV-01421. Written evidence reports and deposition. Case settled.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s, 54003-54021, Spring Valley, NV. Testimony on behalf of protestant Great Basin Water Network. September 11-26, 2006.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s, 54003-54021, Spring Valley, NV. Testimony on behalf of protestant Great Basin Water Network. September 11-26, 2006.

Montana 22nd Judicial District Court, Big Horn County. Diamond Cross Properties, LLC, and Northern Plains Resource Council, and Tongue River Water Users Association v. State of Montana, Pinnacle Gas Resources. Civil Cause No. DV 05-70. Affidavit provided.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 72787 – 72797, Tickaboo/Three Lakes Basin. Testimony on behalf of Sierra Club, Indian Springs. November 28 – 30, 2005.

Earlier, several cases before the Nevada State Environmental Commission, on behalf of Great Basin Mine Watch.

CURRICULUM VITAE

MILLER, GLENN C.

Address (Work) Department of Natural Resources and Environmental Sciences
Mail Stop 199
University of Nevada
Reno, NV 89557
(775) 784-4108 FAX 775-784-4553 775-846-4516 (cell)
email: gcmiller@unr.edu

Born November 17, 1950

Education:

University of California, Santa Barbara, CA	B.S. Chemistry	1972
University of California, Davis, CA	Ph.D. Agricultural Chemistry	1977

Employment:

Univ. of Nevada, Reno	Aug-2009-present	Professor, and Director of the Graduate Program in Environmental Sciences
	2008-2009	On leave for 11 months serving as Manager, Environmental Exposure Assessment, Valent USA Corporation, Walnut Creek CA
	2007-2008, 2010-present	President UNR Nevada Faculty Alliance
	1995-2006	Director, Graduate Program in Environmental Sciences and Health
	1998-2004	Director, Center for Environmental Science and Engineering
	1989-	Professor
	1983-89	Associate Professor
	1979-83	Assistant Professor
	1978-79	Lecturer
Environmental Protection Agency	1977-78	Research Chemist

Professional Societies:

American Chemical Society, Agrochemicals Division and Environmental Division
American Association for the Advancement of Science
Society of Environmental Toxicology and Chemistry
Sigma Xi

Awards:

Thornton Peace Prize (1982)
Junior Faculty Research Award (1982)
UNR Foundation Professor (1991)
Conservationist of the Year, Nevada Wildlife Federation (1995)
College of Agriculture Researcher of the Year (1998)
Friend of the Lake Award, League to Save Lake Tahoe (2001)

Other Professional Activities

Environmental Protection Agency: Competitive Grants Review Panel 1985-1995
Environmental Protection Agency: Advisory Committee on Mining Waste 1991-1993
Environmental Protection Agency: Stakeholder Advisory Committee on Commodity Mercury 2007
Nevada Division of Environmental Protection: Technical Advisory Committee on the Carson River Superfund Site 1991-1994
American Chemical Society, Division of Environmental Chemistry: Chair of the Student Awards Committee 1988-1992
American Chemical Society, Division of Environmental Chemistry: Chair of the Awards Committee 1997-2002
UNR Environmental Studies Board: Chairman 1987-1991
UNR Environmental Science and Health Graduate Program: Director 1995-2006
Consultant to various public interest organizations, companies and law firms
Hydrology/Hydrogeology Graduate Faculty: Member 1989-present
Reviewer for numerous environmental chemistry journals
Co-owner and vice-president: Nevada Environmental Laboratories (Las Vegas and Reno) 1990-1999
Manager, Environmental Exposure Assessment, Valent USA Corporation 8/2008- 8/2009

Courses Taught

Humans and the Environment: Environment 100
Environmental Toxicology: NRES 432/632
Environmental Chemicals: Exposure, Transport and Fate: NRES 433/633
Analysis of Environmental Contaminants: NRES 430/630
Risk Assessment, NRES 793C
Global and Regional Issues in Environmental Science: NRES 467/667

Community and Conservation Service Activities

City of Reno, Charter Review Commission: Chairman 1990-93
Peavine Grade School PTA: Co-President 1990-1992
Sierra Club Mining Committee (national): Co-Chair 1989-1992
League to Save Lake Tahoe Board of Directors: 1986-1999
Mountain and Desert Research Fund: 1987-present
Dupont-Conoco Environmental Leadership Award in Mining Committee: 1989-1994
Nevada Interagency Reclamation Award Committee: 1990-1992
Washoe County School District Science Advisory Board: 1992-2000
Chairman, 1993-94
Earthwords: Board Member 1999-present
Tahoe Baikal Institute: Board Member 1998-present, Chair 2002-2003
Environmental Law Alliance Worldwide Board Member: 2000-present, Chair:2009
Great Basin Mine Watch: Board Member 1994-present, Chair 2001-2006
Center for Science in Public Participation: Board Member 1998-present
Great Basin Institute, Board Member 2000-present, Chair 2001-present
United Nations Environmental Program Committee for Development of a Code for Use of Cyanide in Mining: 2000-2002
Mining, Minerals and Sustainable Development, Assurance Group Committee Member, 2000-2002
National Research Council committee on Methyl Bromide: 1999-2001
National Research Council committee on Mining Technology: 2000-2002

National Research Council committee on USGS Mineral Resources Program, 2000-2003
US Environmental Protection Agency Committee on Management of Mercury Stores in the U.S. 2007

Research Interests: Remediation of mine waste contamination. Mining pit lake water quality. Fate and transport of organic compounds in soils and the atmosphere. Methods of remediation of gasoline contaminated soils; Photochemical transformation of organic contaminants on soil surfaces. Instrumental development of chromatographic systems.

Grants Received: (1982-present)

$ 14,550 "Atmospheric Photolysis of Pesticides," A Junior Faculty Research Award from the UNR Research Advisory Board, 1982.

$ 3,000 "Photolysis of CGA-41065," CIBA GEIGY Corporation, 1982.

$ 4,000 "Chemotaxonomy of Sagebrush Using High Performance Liquid Chromatography," Intermountain Research Station USDA, 1984.

$ 83,000 "Analysis of Bovine Tissue for Chlorinated Hydrocarbons," Environmental Protection Agency, 1984-85.

$ 18,300 "Photooxidation of Sulfide Containing Pesticides on Soil Surfaces," Western Regional Pesticide Impact Assessment Program, 1984.

$ 2,500 "Identification of Sagebrush Taxa Based on Liquid Chromatographic Analyses of Phenolics" Research Advisory Board, 1986.

$235,500 "Factors Affecting the Photolysis of Dioxins on Soil Surfaces," U.S. Environmental Protection Agency, 1986-89.

$ 15,160 "Vapor Phase Photolysis of Phorate," American Cyanamid Corporation, 1987.

$ 2,500 "Identification of Sagebrush Taxa Based on Liquid Chromatographic Analyses of Phenolics," UNR Research Advisory Board, 1987.

$ 48,792 "Upgrading Municipal Wastewater Effluents for Urban Water Reuse through Phytochemical Oxidations: System Development and Operational Criteria," U.S. Geological Survey, State Water Research Institute Program (Co-P.I. with Richard Watts), 1986-88.

$ 17,200 "Vapor Phase Photolysis of Malathion," American Cyanamid, 1988.

$ 16,460 "Aging Groundwater: A comparison of the Fluorocarbon Method to the Tritium Method," U.S. Geological Survey, State Water Research Institute Program (Co-P.I. with K. Sertic), 1988-89. (Competitive Grant, State of Nevada) Terminated 6-89.

$206,000 "In Situ Treatment of Organic Hazardous Wastes in Surface Soils Using Fenton's Reagent." U.S. Environmental Protection Agency (Co-P.I. with Richard Watts), 1988-89. (Competitive Grant, national)

$ 23,200 "Evaporation of Gasoline from Soils," Nevada Division of Environmental Protection Co-P.I. with Susan Donaldson), (Contract).

$ 50,000 "Photolysis of Pesticides on Soils," American Cyanamid Corporation (Unrestricted Grant, noncompetitive)

$ 15,600 "Vapor Phase Photolysis of Diazinon and Methyl Parathion" Western Region Pesticide Impact Assessment Program (USDA) (competitive) 1989-90

$ 30,000 "Interface for a Capillary electrophoresis Effluent and a Mass Spectrometer" Linear Corporation 1989-90. (Co P.I. with Murray Hackett) (contract)

$ 15,000 "UV-Gas Chromatographic Dectector" Linear Corporation 1990. (Co P.I. with Murray Hackett) (Noncompetitive grant)

$153,000 "Enhancement of Photodegradation of Pesticides in Soil by Transport Upward in Evaporating Water" (USGS Competitive) 1991-94

$ 50,000 "Pit Water from Precious Metal Mines" U.S. Environmental Protection Agency, 1992-94

$ 91,000 "Remediation of Acid Mine Drainage at Leviathon Mine" Lahontan Water Quality Control Board. (Contract, Co P.I. with Tom Wildman, Colorado School of Mines) 1992-94.

$159,000 " Ecological Toxicology of Metam Sodium and it Derivatives in the Terrestrial and Riparian Environments of the Sacramento River" California Fish and Game, 1992-1995 (G.C. Miller project, part of a larger project with George Taylor at the Desert Research Institute)

$43,092 “Atmospheric Transport and Deposition of Organophosphates and Other Pesticides as Input to Sierra Nevada Surface Waters” USDA-NRI. 1995-98. Co-P.I. with P.I. James N. Seiber. Task 2.

$80,427 “Linked Techniques for Contaminant Removal from Soil in Arid/Semiarid Environments” Dept. of Energy. 1993-96. Co.P.I with James N. Seiber.

$107,000 “Chemical Environmental Problems Associated with Mining” NIEHS 1993-96. Core B portion. This was a project of a larger Superfund Grant to UNR. James N. Seiber, P.I.

$36,900 “Protocol for Evaluation of Pesticide Photodegradation” Dow-Elanco. 1995-97. (Contract)

$45,000 “Photolysis of Pesticides” Dupont Chemical Company. 1995-98. Unrestricted gift to support ongoing research.

$275,000 “Remediation of Acid Mine Drainage at the Leviathan Mine”. Nevada Division of Environmental Protection. 1996-99

$5000 “Evaluation of Limnology and Water Quality of a Porphyry-Copper Pit Mine Lake” Public Resource Associates 1996.

$767,000 Geochemical, Biological and Economic Impacts of Arsenic and Related Oxyanions on a Mining-Impacted Watershed” NSF-EPA, 1997-01

$46,000 “Remediation of Acid Mine Drainage at the Leviathan Mine”. Lahontan Regional Water Quality Control Board, 2000-2001

$30,000 "Use of Sulfate-Reducing Bioreactors to Remove Zinc in Mine Drainage" Placer Dome Corporation. 2000-2001

$50,000 “Release of Gasoline Constituents from Marine Engines to Lake Tahoe” Lahontan Regional Water Quality Control Board, 1998-1999

$70,000 "Impact of Marine Engine Exhaust on Pyramid Lake" U.S. Environmental Protection Agency, in cooperation with the Pyramid Lake Paiute Tribe. 2000-2001.

$570,000 "An Environmental Assessment of the Impacts of Polycyclic Aromatic Hydrocarbons in Lake Tahoe and Donner Lake" California Regional Water Quality Control Board, Lahontan Region. 2001-2003.

$126,000 "Operation of a Bioreactor at the Leviathan Mine" Contract with ARCO, 2001-2002

$75,000 Trifluroacetic Acid in Antarctic Ice, National Science Foundation 2001-2004

$190,500 “Mercury Deposition Associated with Mining, U.S. Environmental Protection Agency, 2002-2004

$53,000 Passivation of Acid Generating Rock at the Golden Sunlight Mine, Placer Dome Corporation 2002-2003

$520,000 “Operation of a Bioreactor at the Leviathan Mine" Contract with ARCO, 2003-2007

$250,000 “Risk Assessment and Fate of Polyacrylamide and Acrylamide in Irrigation Canals and Receiving Water” A subcontract from the Desert Research Institute on a project from the U.S. Bureau of Reclamation. 2004-2008

$55,000 Passivation of Acid Generating Rock, Freeport McMoran, 2009-2010

$75,000 Biofuel crops on arid lands, Co-P.I. U.S. Department of Energy, 2010-2011

Publications:

G.C. Miller and D.G. Crosby, "Photodecomposition of Sustar^{R} in Water." J. Agric. Food Chem. 26:1316 (1978).

G.C. Miller and R.G. Zepp, "Effects of Suspended Sediments on Photolysis Rates of Dissolved Pollutants." Water Research 13:453 (1979).

G.C., Miller, M.J. Miille, D.G. Crosby, S. Sontum and R.G. Zepp, "Photosolvolysis of 3,4-Dichloroaniline in Water: Evidence for an Aryl Cation Intermediate." Tetrahedron 35:1797 (1979).

G.C. Miller and R.G. Zepp, "Photoreactivity of Pollutants Sorbed on Suspended Sediment." Environ. Sci. Technol. 13:860 (1979).

G.C. Miller, R. Zisook and R.G. Zepp, "Photolysis of 3,4-Dichloroaniline in Natural Waters." J. Agric. Food Chem. 28:1053 (1980).

G.C. Miller, R.G. Warren, K. Gohre and L. Hanks, "A Gas Chromatographic Method for Determining Strychnine Residues in Alfalfa." J. Assoc. Off. Anal. Chem. 65:901 (1982).

G.C. Miller and W.W. Miller, Eds. "Effect of Sewage on the Truckee River." A symposium published by the University of Nevada, College of Agriculture (1982).

G.C. Miller and R.G. Zepp, "Extrapolating Photolysis Rates from the Laboratory to the Environment." Residue Reviews 85:89 (1983).

G.C. Miller and D.G. Crosby, "Pesticide Photoproducts: Generation and Significance." J. Clin. Toxicol. 19:707 (1983).

G.C. Miller, W.W. Miller, J.W. Warren and L. Hanks, "Soil Sorption and Alfalfa Uptake of Strychnine Applied as an Agricultural Rodenticide." J. Environ. Quality 12:526 (1983).

G.C. Miller and D.G. Crosby, "Photooxidation of 4-Chloroaniline and N-(4-Chlorophenyl)-Benzene-sulfonamide to Nitroso- and Nitro-Products." Chemosphere 12:1217-1227 (1983).

K. Gohre and G.C. Miller, "Singlet Oxygen Generation on Soil Surfaces." J. Agri. and Food Chem. 31:1104-1108 (1983).

R.G. Zepp, P.F. Schlotzhauer, M.S. Simmons, G.C. Miller, G.L. Baughman and N.L. Wolfe, "Dynamics of Pollutant Photoreactions in the Hydrosphere." J. of Fresenius Z. Anal. Chem. 319:119-125 (1984).

K. Gohre and G.C. Miller, "Photochemical Generation of Singlet Oxygen on Non-transition Metal Surfaces." J. Chem. Soc. Faraday Trans. I 81:793-800 (1985).

R.V. Tamma, G.C. Miller and R. Everett, "High-Performance Liquid Chromatographic Analysis of Coumarins and Flavonoids from Section Tridentatae of ***Artemisia***." J. Chromatography 322:236-239 (1985).

K. Gohre, R. Scholl and G.C. Miller, "Singlet Oxygen Reactions on Soil Surfaces." Environ. Sci. Technol. 20:934-938 (1986).

K. Gohre and G.C. Miller, "Photooxidation of Thioether Pesticides on Soil Surfaces." J. Agric. Food Chem. 34:709-713 (1986).

B.R. Smith, G.C. Miller, R.W. Mead and R.E.L. Taylor, "Biosynthesis of Asparagine and Taurine in the Freshwater Prawn, ***Macrobrachium rosenbergii*** (De Man)." Comp. Biochem. Physiol. 87B(4):827-831 (1987).

B.R. Smith, G.C. Miller and R.W. Mead, "Taurine Tissue Concentrations and Salinity Effect on Taurine in the Freshwater Prawn ***Macrobrachium rosenbergii*** (De Man)." Comp. Biochem. Physiol. 87A(4):907-909 (1987).

G.C. Miller and V. Hebert, "Environmental Photodecomposition of Pesticides." In: University of California publication - Fate of Pesticides in the Environment (J.W. Biggar and J.N. Seiber, eds.) Chapt. 8, p. 75-86 (1987).

G.C. Miller and R.G. Zepp, "2,3,7,8-Tetrachlorodibenzo-p-dioxin: Environmental Chemistry." In: Solving Hazardous Wastes Problems: Learning from Dioxins (J.H. Exner, ed.) American Chemical Society Symposium Series 338, Chapter 6, pp. 82-93 (1987).

C.R. Blincoe, V.R. Bohman, G.C. Miller, R.L. Scholl, W.W. Sutton and L.R. Williams, "Excretion and Tissue Concentration of Pentachlorophenol Following Controlled Administration to Cattle." J. Animal Sci. 65 Supplement #1 (1987).

G.C. Miller, V.R. Hebert and R.G. Zepp, "Chemistry and Photochemistry of Low-Volatility Organic Chemicals on Environmental Surfaces." Env. Sci. Tech. 21:1164-1167 (1987).

V.R. Bohman, C.R. Blincoe, G.C. Miller, R.L. Scholl, W.W. Sutton and L.R. Williams, "Biological Monitoring Systems for Hazardous Waste Sites." EPA Final Report #CR 809 787 (1988).

F.M. Wilt, G.C. Miller and R.L. Everett, "Monoterpene Concentrations of Litter and Soil of Singleleaf Pinyon Woodlands of the Western Great Basin." Great Basin Naturalist 48:228-231 (1988).

K. Mongar and G.C. Miller, "Vapor Phase Photolysis of Trifluralin in an Outdoor Chamber." Chemosphere 17(11):2183-2188 (1988).

G.C. Miller, V.R. Hebert and W.W. Miller, "Effects of Sunlight on Organic Contaminants at the Atmosphere - Soil Interface." In: Reactions and Movement of Organic Chemicals in Soils (B. Sawhney, ed.) SSSA Special Publication No. 22, pp. 99-110 (1989).

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Woodrow, J., J. N. Seiber, and G.C. Miller, "A Correlation to Estimate Emission Rates for Soil-Applied Fumigants" Journal of Agricultural and Food Chemistry, 51:939-943 (2011)

P.O BOX 1025, CARSON CITY, NV 89701
PHONE (775) 720-7674 • EMAIL RLSEILER@JUNO.COM

Ralph L. Seiler

PROFESSIONAL EXPERIENCE

Hydrologist
1979-2010 (retired) U.S. Geological Survey Carson City, NV

- Principal investigator for numerous water-quality investigations of surface water and groundwater, including identifying sources of phosphorus in the Carson River, sources of nitrate and bacteria in groundwater, and sources and distribution of TCE in groundwater near a landfill on an Air Force Base in Utah.
- Principal investigator for USGS Fallon leukemia investigation of ground-water quality which involved working closely with CDC, ATSDR, and the State of Nevada. Participated in many public meetings with State and Federal Agencies to explain results of findings related to the presence of arsenic, tungsten, uranium, and polonium-210 in Fallon area groundwater.
- Author of journal articles describing geochemical processes that result in exposure of the public to toxic trace elements and radionuclides.

PUBLICATIONS

Seiler and Wiemels, *in review at Environmental Health Perspectives*. Occurrence of ^{210}Po and biological effects of low-level exposure: The need for research.

Seiler, 2011a, Physical setting and natural sources of exposure to carcinogenic trace elements and radionuclides in Lahontan Valley, Nevada. Chemical-Biological Interactions [Epub ahead of print DOI:10.1016/j.cbi.2011.04.004]

Seiler, 2011b, ^{210}Po in Nevada groundwater and its relation tor gross alpha radioactivity. Groundwater 49(2):160-171

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EDUCATION

Ph.D. Environmental Chemistry
1996-1999 University of Nevada, Reno Reno, NV

B.S./M.S. Biology
1969-1975 University of Utah Salt Lake City, UT

Michele C. Adams, P.E.
LEED AP
Principal Water Resources Engineer

Meliora Environmental Design, LLC

Relevant Experience

Ms. Adams is a Principal Engineer and founder of Meliora Environmental Design. For more than 25 years, her work has encompassed environmentally sensitive site design and sustainable water resources engineering. Building on a multi-disciplinary approach, her work includes both master planning and design for campuses, urban restoration projects, commercial, industrial and residential installations, public facilities, and environmental education centers. In all her work, Ms. Adams seeks to combine sound engineering science with an understanding of natural systems. She is a frequent lecturer and educator on the topics of water and sustainability, and has provided technical expertise to clients ranging from watershed advocacy organizations to corporations. Ms. Adams was one of the principle authors of the Pennsylvania Stormwater Manual, and serves on the U.S. Green Building Council's Technical Advisory Group for Sustainable Sites. She frequently serves as an expert witness with regards to stormwater and water quality issues. Current design projects in which Ms. Adams is engaged include the following:

Stormwater Management for Green and Public Properties, City of Philadelphia: Led a team of engineers, landscape architects, and planners in developing stormwater designs for the City of Philadelphia public properties. The stormwater and landscape designs are intended to reduce impacts to the City's combined sewer system, provide economic cost savings, and promote green infrastructure. Projects have included parks, schools, recreation facilities, and "green streets". A number of projects have been documented through construction and are being (or have been) built.

Purdue University Stormwater Plan: Development of a Stormwater Plan for retrofitting an urban campus to implement an LID approach and incorporate green infrastructure to improve water quality and reduce stormwater runoff volumes. Protection and recharge of drinking water source (groundwater) and water quality protection is a key component of recommendations.

Purdue University Site and Stormwater Improvements at the Mackey Football Fields and Ross-Ade Stadium Parking Lot, West Lafayette, IN: Design of nearly 3 acres of infiltration beds located beneath the Purdue Boilmaker's football practice fields to manage stormwater for the upper campus athletic complex. At the Ross-Ade Stadium, design of bioretention systems to pre-treat runoff from the parking lot and bordering roadways, a drainage area of nearly 6 acres, before the system connects to the infiltration beds under the adjacent football practice fields.

Stroud Water Research Center Environmental Education Center, Academy of Natural Sciences, Avondale, PA: For one of the nation's premier water research and education facilities, provided sustainable site design engineering related to stormwater management including rain gardens, water reuse, and green roof.

U.S. Botanic Garden Bartholdi Park, Washington, D.C.: Designing stormwater management measures in the landscape to serve as demonstration sites as well as to demonstrate compliance with the new Federal Regulations for stormwater management as part of Section 438 of the Energy Independence and Security Act. The project is also seeking certification from the Sustainable Sites Initiative.

High Performance Landscapes, New York City Parks and Recreation: Ms. Adams served as one of four authors in development of the New York City's *High Performance Landscapes* document, specifically addressing water issues. This publication will be the third in the series that began with *High Performance Buildings*.

Special Qualifications

Twenty-five years of experience in civil and water resources engineering.

Sustainable site design engineering, including Stormwater Best Management Practices, Low Impact Development, (porous pavement, bioretention, tree trenches, vegetated roofs, etc) and alternative wastewater treatment systems (wetlands, drip irrigation, recirculating filters). Design for projects seeking LEED certification.

Watershed studies, computer modeling, stormwater sampling, stream flow monitoring, NPDES permit applications, mixing zone analyses, pollution prevention plans.

Professional Credentials

Bachelor of Science Civil Engineering
Pennsylvania State University, State College, PA, 1984

Graduate Coursework Water Resource Engineering
Villanova University, PA 1997-2001

Registered Professional Engineer in Delaware, Pennsylvania, Virginia, Maryland

LEED Accredited Professional

Waterview Recreation Center, City of Philadelphia and Pennsylvania Horticultural Society: For an existing urban recreation center, design of "green infrastructure" stormwater elements to improve community amenities and reduce combined sewer overflows. Elements include stormwater tree trenches, stormwater planter boxes, and a cistern for the community garden. *This project has recently been the subject of a GreenTreks video on stormwater.*

Greenstreets Design, East Falls: Led a team of design professionals (traffic engineers, landscape architects, pedestrian designers, stormwater engineers) in the design of a "complete" street for an urban neighborhood, including two design charettes with regulatory and design professionals from various city and state agencies. The goal was to develop a complete street that addressed stormwater, various transportation modes, and neighborhood greening and revitalization.

University of Pennsylvania Shoemaker Green, Philadelphia: Design of a passive open space on Penn's Campus that captures runoff generated by new and existing impervious surfaces into site and landscape features throughout the site. The project is also seeking certification from the Sustainable Sites Initiative.

Three Groves Ecovillage: Evaluating the Zoning Overlay for the proposed Ecovillage as well as designing the Water system, Wastewater Collection system, and stormwater measures for the site. Consisting of small residential buildings, community greenhouses, community buildings, natural pools, a constructed wetland treatment system, and bioswales, the proposed Ecovillage development is a model sustainable "green" neighborhood.

Philadelphia Zoo Master Plan: Development of water and environmental recommendations for the Zoo Master Plan, with focus on stormwater measures integrated into the Zoo's landscape to address flooding problems while promoting sustainability.

Greening and Stormwater Retrofits for Urban Schoolyards, Philadelphia: For two existing urbanized school yards (Greenfield School and Independence Charter School) that previously consisted only of asphalt, designed elements intended to both capture the first inch of runoff and provide greening, environmental education, and reduce heat island effects. Components include rain gardens, porous asphalt, porous pavers, and vegetated swales. *Greenfield School has recently been the subject of a GreenTreks video on stormwater.*

Stormwater Plans and Environmental Site Design Analysis for Maryland Projects: For the Chesapeake Bay Foundation and Audubon Society, Ms. Adams led an effort to evaluate various project sites in Maryland and provide recommendations and cost estimates for implementing landscape and stormwater measures to achieve the goals of Maryland's ESD process.

Okehocking Nature Center, Willistown Township, PA: Sustainable site design engineering for new Environmental Education Center, including stormwater management and wastewater treatment systems that are integrated with the natural landscape restoration.

Levin Tract Wooded Wetland Park, Radnor, PA: For the urbanized Radnor, PA area, developed a restoration concept design to convert an abandoned vacant parcel into a wooded wetland park area that will improve water quality from a 40-acre urban drainage area by creating a series of low, wooded wetland depressions and planting areas.

Professional Employment History

2007- Present
Principal Engineer and Founder
Meliora Environmental Design
Kimberton, PA

1997- 2007
Principal Engineer
Cahill Associates, West Chester, PA

1991-1997
Project Manager
Roy F. Weston, Inc., West Chester, PA

1984-1991
Project Engineer
Cahill Associates, West Chester, PA

Professional Memberships

U.S. Green Building Council – Sustainable Sites Technical Advisory Committee (SS TAG)

Member, American Society of Civil Engineers, Environmental Water Resources Institute

Member, Pennsylvania Association of Environmental Professionals

Member, American Water Resources Association

Visiting Guest Lecturer; University of Pennsylvania Schools of Architecture and Landscape Architecture; Philadelphia University, and Temple University

East Vincent Planning Commission Chairman

Ralston House, University of Pennsylvania: Design of stormwater elements to support an urban landscape restoration at an existing healthcare facility for the elderly.

Tyler Arboretum Path System: Designed a system of porous asphalt paths through an existing arboretum to improve access and address localized erosion problems.

Hershey Gardens Stormwater Plan: Developed program of rain gardens, wetlands, and restoration measures to address existing erosion and flooding problems.

North 3rd Street Corridor Sustainable Affordable Housing Plan, Philadelphia: With SMP Architects, designing guidelines for sustainable affordable housing, including stormwater measures to reduce combined sewer overflows and meet new City of Philadelphia ordinances.

Hamilton Children's Zoo at the Philadelphia Zoo: Design of site elements, including stormwater elements that provide educational opportunities, such as wetlands, green roofs, porous paths, and cisterns.

Oxford Library: Sustainable site design and engineering for a library addition to an urban library that includes porous pavers, rain gardens, and public outdoor gathering spaces to promote environmental education.

Mount Saint Joseph Academy Stormwater Improvements: With the Pennsylvania Horticultural Society, design of landscape-based restoration measures to improve stormwater management and educational opportunities at an existing school.

Chanticleer Garden: Stream daylighting of buried tributary and floodplain restoration.

Fire Engine 38: Site design of a new Fire Station in Philadelphia to include green roof, bioretention, and landscape restoration. Project will be LEED certified.

John Hopkins Sustainability House: Site design of a building at John Hopkins to create a Sustainability House and define sustainability criteria for University.

Stroud Model My Watershed: Providing technical expertise in the development of an educational watershed modeling tool being developed through funding from the National Science Foundation. Tool will allow interactive evaluation of development impacts on water balance and water quality, and allow alternative designs to be evaluated for benefits of groundwater restoration, stream health, and water quality.

Panther Hollow Watershed Restoration: Developing a watershed restoration plan which includes hydrologic modeling of the natural and existing conditions, using WinSLAMM, and design of two pilot projects to include elements such as an infiltration trench to capture adjacent street runoff, and retentive grading/infiltration berms to manage compacted lawn on a golf course.

For ten years prior to forming Meliora (1997 – 2007), Ms. Adams was a Principal Engineer with Cahill Associates, where she successfully directed and participated in all aspects of a number of projects.

Pennsylvania Stormwater Best Management Practices Manual, Pennsylvania DEP, co-author of State Manual describing structural and non-structural BMPs, Control Guidelines, calculation methodologies, and specifications, including a volume-based approach to stormwater.

Environmental and Stormwater Master Plan, UNC Chapel Hill, NC, Environmental master planning for sustainable stormwater approach to address large university expansion plan. Detailed hydrologic computer modeling performed in US EPA SWMM to evaluate existing infrastructure and recommend stormwater measures. Represented new LID approach in stormwater for UNC and was recognized by Sierra Club as a "Top Ten Building Better II" project.

Grey Towers National Monument, National Forest Service, Sustainable site design, including various stormwater measures for historic gardens, porous pavement, water and wastewater systems.

Washington National Cathedral, D.C., Restorative stormwater measures for Cathedral site and woods, including various infiltration measures (at source of runoff), infiltration for road system, channel stabilization, etc. Second phase included infiltration trenches integrated in to new outdoor amphitheater.

Mill Creek Community Garden and Clark Park Urban Stormwater Projects, Philadelphia, PA, Design of urban stormwater systems that collect runoff from City streets and infiltrate/manage water in urban green spaces such as community gardens and new basketball courts.

Cusano Center at John Heinz National Wildlife Refuge, Tinicum, PA, Sustainable site design for educational center, including various stormwater elements.

Springbrook Low Impact Development, Lebonon County, PA, Design of full LID stormwater system for 247 residential units in karst area, including over 120 individual stormwater systems (vegetated infiltration beds, infiltration trenches, rain gardens, porous pavements, etc.).

Bartrams Garden Master Plan, Philadelphia, PA, Restorative stormwater management recommendations for Master Plan of historic garden.

Regent Square Gateway, Nine Mile Run, Pittsburgh, PA, Concept and schematic design for urban stream and park "gateway".

Ford Rouge Stormwater Management, Dearborn, MI, Stormwater planning and design for major industrial facility re-development (Porous pavement, bioretention swales, vegetated systems).

Woodlawn Library, Wilmington, DE, Design of urban stormwater measures at new public library to reduce stormwater in combined sewers. Porous parking, bioretention, cisterns with re-use, stormwater planter boxes.

From 1991 through 1997, Ms. Adams was a Project Engineer and Project Manager at Weston.
Stormwater Management Programs and NPDES permitting Between 1992 and 1996, Ms. Adams developed and implemented stormwater management and sampling programs at over fifty industrial, commercial, and military facilities throughout the United States, including the Bureau of Engraving and Printing, Philadelphia International Airport, and various industrial facilities. These programs focused on reducing stormwater and water quality impacts from existing facilities.

Hydrologic, Hydraulic, and Mixing-Zone Modeling For a variety of watershed studies including Act 167 Plans, Ms. Adams conducted hydrologic and hydraulic modeling using various mathematical computer models, including USDA TR-20, EPA SWMM, and COE HEC models. Ms. Adams also performed floodway

Expert Testimony within Past Three Years

2010 **Blue Mountain Preservation Association vs Alpine Development Rose Resorts;** Pennsylvania Environmental Hearing Board. Expert witness on behalf of BMPA on issues related to stormwater management and water quality.

2010 **Koziell and Perrini vs Madison Township; Lackawanna Court of Common Pleas;** Expert witness on adverse stormwater impacts of road improvements.

June 2010 **West Vincent Zoning Hearing Board; Flather Property;** Testimony on behalf of Green Valleys Association and PennFuture related to impacts of **water** quality on variance request for stream buffer and wetland setback requirements.

Jan 2010 **West Pikeland Zoning Hearing Board;** Testimony on behalf of Green Valley Association related to impacts of water quality and stream health on variance requests to environmental ordinances.

2009/2010 **Tim and Jamie Lake vs The Hankin Group;** Court of Common Pleas Chester County; Expert witness on stormwater design and flooding.

2008-2009 **Crum Creek Neighbors vs DEP, et al;** Pennsylvania Environmental hearing Board; Expert witness on stormwater design review and impacts on flooding and water quality.

2007-2008 **Glenhardie Condominium vs. Realen Associates; Appeal of NPDES Post-construction Stormwater Management Permit;** Expert witness on behalf of Glenhardie related to stormwater design and flooding. Permit was withdrawn.

Expert Analysis and Comment within Past Three Years

2009/2010 **Pennsylvania Turnpike Expansion Project;** on behalf on National Park Service Valley Forge National Park and Valley Creek Coalition. Expert services related to review and comment of stormwater design and impacts on water quality and stream conditions.

2009/2010 **City of Philadelphia Longterm Control Plan;** on behalf of Natural Resources Defense Council and PennFuture; review of technical reports, policy documents, and draft permit conditions on issues related to stormwater management, water quality, stream health, and compliance with Clean Water Act and EPA Longtern Control Policy.

2010 **City of Chattanooga MS4 Permit**: For City of Chattanooga, providing technical guidance for incorporation of stormwater measures to address and restore impaired streams and meet TMDL requirements. Training sessions for municipal officials and program development.

Publications

Design for Flooding: Architecture, Landscape, and Urban Design for Resilience to Climate Change; By Donald Watson and Michele Adams; Wiley Publishing, Hardcover Nov 2010.

Park Design for the 21st Century: High Performance Landscape Guidelines; New York City Parks Department and NYC Design Trust; Nov 2010.

Porous Asphalt Pavement: 20 Years and Still Working, Michele Adams, Published in Stormwater Magazine May/Jun 2003

Presentations and Conference Proceedings

2010

Nov Greenbuild USGBC National Conference; New Directions in Stormwater Management and LEED
Nov AWRA National Conference; New Direction in Water Management
Oct Delaware Valley Green Building Council; New Directions in Stormwater Management in Philadelphia
Sep Pittsburgh Parks Conservancy; Michele Adams; "What's Going on in Panther Hollow" and examples of innovative engineering solutions to stormwater impacts on the watershed; Pittsburgh, PA
May "Sustainable Stormwater Management for Municipal Officials"; Lecture series for municipal officials sponsored by Brandywine Valley Association
Apr "Stormwater Management in Pennsylvania", Environmental Law Forum, Harrisburg, PA
Apr "Rainwater Management", Institute for Conservation Leadership
Mar "How to Challenge a Stormwater Permit and Win: A Look at the Crum Creek Neighbors Decision" Michele Adams, James Schmid, and John Wilmer; Schuylkill Watershed Congress; Pottstown, PA

2009

Dec "Bio-retention, Vegetative roofs, rain gardens, stormwater management" sponsored by East Nantmeal Township Environmental Council
Oct "Regenerative Urban Stormwater: Example Projects in the Philadelphia Region" Michele Adams and Susan McDaniels Pennsylvania Stormwater Conference; Villanova, PA
Oct Housing and Water: Syncing Neighborhood Development, Stormwater Management, and Water; AIA Design on the Delaware
Oct "Sustainability and Stormwater Management: Green Infrastructure" American Planning Association National Conference
Sept LID and Stormwater; 16th Annual Erosion Control Conference
May "Green Infrastructure and Urban Revitalization" Greening the Heartland Conference, Detroit, MI
May "Protecting Our Natural Resources: Design Leadership for the Next 100 Years" AIA National Conference, San Francisco.
May "Putting It Into Practice: Low Impact Development And Stormwater Management Training" Pennsylvania Land Conservation Conference
May "Reconnecting Water, Soils, and Vegetation: Stormwater Management in the Built Environment" ASLA PA/DE Annual Meeting.
Mar "Water, Soils, and Vegetation: Sustainable Site Design" Purdue University Sustainability Conference
Mar "Promoting LID Redevelopment in the Anacostia Watershed" Washington, DC

2008

Jan AIA/DVGBC, Philadelphia; Porous Pavement: How, Why, and When
Mar DVGBC Best of GreenBuild

2007

Nov USGBC GreenBuild, Chicago; Michele Adams; UNC Chapel Hill: A Campus-wide approach for Growth and Sustainability

Aug "Urban Stormwater and LEED"; Michele Adams, Energy Coordinating Agency of Phila; Demystifying LEED for Homes Event.

May "Low Impact Development: What's Important and What Should be Monitored"; Michele Adams and Wesley Horner; Tampa; 9th Conference on Stormwater Research & Watershed Management; Fla DEP

May "Low Impact Development"; Wesley Horner and Michele Adams; ASCE EWRI World Environmental &Water Resources Congress; Conference; Orlando, Fla

April "Integrating Sustainable Stormwater into the Campus"; Michele Adams and Thomas Cahill; Baltimore, MD; Smart and Sustainable Campuses Conference, EPA/Society for College and University Planning.

April; "Stormwater Management at UNC Chapel Hill: A Plan for Growth and Sustainability"; Jill Coleman, UNC, and Michele Adams; Wilmington, NC, 2nd National Low Impact Development Conference

April "Using the BMP Manual to Meet NPDES Requirements"; Michele Adams; State College, PA; Chesapeake Bay Foundation Confluence 2007, Connecting Communities to Creeks.

March "Porous Pavements"; Michele Adams, Public information session hosted by the City of Wichita

2006

Nov "Urban Stormwater BMPs: Finding Space for Stormwater in the Urban Environment", Michele Adams; Baltimore, MD; AWRA 2006 Annual Water Resources Conference

Nov "Sustainable Site Design"; Michele Adams; Philadelphia, PA; Design on The Delaware AIA Regional Conference

Sept "Stormwater Site Design: porous Asphalt and Other Innovative Stormwater Techniques"; Michele Adams; Kansas City, MI; American Public Works International Congress and Exposition

Sept "Sustainable Stormwater Management"; Michele Adams; Pittsburgh, PA; 3 Rivers Wet Weather 8th Annual Sewer Conference

Sept "Regent Square Gateway Vision for Nine Mile Run"; Marijke Hecht and Michele Adams; University of Pittsburgh, PA

Sept "The Etowah Habitat Conservation Plan and Runoff Limits"; Michele Adams; Atlanta, GA; Public workshops sponsored by Etowah Watershed Organization and the River Basin Center Institute of Ecology University of Georgia.

June Blair County LID Workshop; Michele Adams; Hollidaysburg, PA;

June Penn State Visitor Center LID Design; Michele Adams; State Colege, PA; Penn State Computational Methods in Stormwater Management

May "Rams Head Extensive Green Roof Design at UNC Chapel Hill"; Andrew Potts and Michele Adams; Boston, MA; Green Roofs for Healthy Cities Conference

May Penn State Visitor Center LID Demonstration Tour; Michele Adams; Pennsylvania Association of Environmental Professionals.

Mar "Porous Asphalt Pavement: The Right Choice"; Michele Adams; Orlando, FLA; NAPA World of Asphalt

Jan "Sustainable Stormwater Management"; Michele Adams; Atlantic City, NJ; NJ ASLA Annual Meeting
Various Dates and Locations in PA: Stormwater Management Workshops for Municipal Officials and Engineers; Sponsored by the Pennsylvania Environmental Council

2005

Dec "Sustainable Design in Our Communities"; Michele Adams and Tavis Dockwiller; Sturbridge, MA; presented by Green Valleys Institute

Nov "Designing Bio/Infiltration Best Management Practices for Stormwater Quality Improvement"; Michele Adams; Madison, WI; University of Wisconsin Professional Development Course

Oct "Springbrook: Residential LID in a Limestone Area; Andrew Potts and Michele Adams; Villanova, PA; 2005 Pennsylvania Stormwater Management Symposium

July "Sustainable Site Design"; Michele Adams; Trenton, NJ; AIA NJ Tectonics of Sustainable Design

June Penn State Visitor Center LID Design; Michele Adams; State Colege, PA; Penn State Computational Methods in Stormwater Management

April "Urban Stormwater BMPs: Finding Space for Stormwater in the Urban Environment*";* Wesley Horner and Michele Adams; Tampa, FLA; 8th Biennial Conf on Stormwater Research & Management.

Mar "Sustainable Site Design"; Michele Adams and Tavis Dockwiller; sponsored by Fulton County, PA

Ruth Ayn Sitler, P.E.
Water Resources Engineer

Meliora Environmental Design, LLC

Relevant Experience

Ms. Sitler is a Water Resources Engineer at Meliora Environmental Design with over seven years of civil engineering experience that includes low impact development and sustainable stormwater management design. To date, her experience has provided her with a vast multi-disciplinary background from which to draw for innovative design projects of all scopes and sizes, and includes commercial and residential construction, educational facility construction, stream restoration projects, abandoned mine reclamation, and pavement management and design. Ms. Sitler also has experience in environmental permitting as well as local government operations.

Current designs in which Ms. Sitler has been engaged include the following:

Greenstreets Design, East Falls: Part of a team of design professionals (traffic engineers, landscape architects, pedestrian designers, stormwater engineers) in the design of a "complete" street for an urban neighborhood, including two design charettes with regulatory and design professionals from various city and state agencies. The goal was to develop a complete street that addressed stormwater, various transportation modes, and neighborhood greening and revitalization.

Three Groves Ecovillage: Evaluating the Zoning Overlay for the proposed Ecovillage as well as designing the Water system, Wastewater Collection system, and stormwater measures for the site. Consisting of small residential buildings, community greenhouses, community buildings, natural pools, a constructed wetland treatment system, and bioswales, the proposed Ecovillage development is a model sustainable "green" neighborhood.

Panther Hollow Watershed Restoration: Developing a watershed restoration plan which includes hydrologic modeling of the natural and existing conditions, using WinSLAMM, and design of two pilot projects to include elements such as an infiltration trench to capture adjacent street runoff, and retentive grading/infiltration berms to manage compacted lawn on a golf course.

Philadelphia Zoo Master Plan: Development of water and environmental recommendations for the Zoo Master Plan, with focus on stormwater measures integrated into the Zoo's landscape to address flooding problems while promoting sustainability.

Special Qualifications

Seven years of experience in civil and water resources engineering.

Sustainable civil/site design engineering, including Stormwater Best Management Practices, Low Impact Development, (porous pavement, bioretention, etc).

Integrated water resource planning; regional watershed planning; computer modeling; environmental , transportation, and construction permitting; local ordinance development and implementation.

Professional Credentials

Post-Graduate Coursework
Coastal Engineering
Old Dominion University, VA
2012-present

Master of Engineering
Environmental Engineering
Pennsylvania State University, PA, 2007

Bachelor of Science
Civil Engineering Technology
Pennsylvania College of Technology, PA 2004

Registered Professional Engineer in Pennsylvania

Certified Surveyor-in-Training in Pennsylvania

Professional Employment History

2011- Present
Water Resources Engineer
Meliora Environmental Design
Phoenixville, PA

Expert Testimony within Past Three Years

Jan 2012 **London Grove Zoning Hearing Board;** Testimony on behalf of Three Groves Ecovillage Development, L.P., related to site design engineering components and conformance to local ordinance standards for conditional use approval.

2010 **Butler County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Butler County Act 167 Stormwater Management Plan.

2010 **Crawford County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Crawford County Act 167 Stormwater Management Plan.

2010 **Mifflin County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Mifflin County Act 167 Stormwater Management Plan.

2010 **Montour County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Montour County Act 167 Stormwater Management Plan.

2010 **Potter County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Potter County Act 167 Stormwater Management Plan.

2010 **Venango County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Venango County Act 167 Stormwater Management Plan.

2010 **Warren County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Warren County Act 167 Stormwater Management Plan.

2008-2011
Civil Engineer Manager and Sr. Civil Engineer
Comm. of Pennsylvania:
PA Dept. of Env. Prot.
(Bur. of Aban. Mine Rec.)
(Bur. of Watershed Mgmt.)
PA Dept. of Transportation
(Bur. of Maint. And Oper.)
Harrisburg, PA

2006-2007
Project Manager
Navarro & Wright Consulting Engineers, Inc.
New Cumberland, PA

2006-2006
Project Designer
Raudenbush Engineer, Inc.
Middletown, PA

2005-2005
Project Designer
Morris & Ritchie Associates
York, PA

2004-2005
Transportation Engineer I
Buchart-Horn, Inc.
York, PA

Professional Memberships

Member, American Society of Civil Engineers, Environmental Water Resources Institute

Expert Analysis and Comment within Past Three Years

2011 **AML-1: The Abandoned Mine Land Inventory Manual;** on behalf of the Pennsylvania Department of Environmental Protection, Bureau of Abandoned Mine Reclamation; Technical review and comment of revisions to the Department of interior, Office of Surface Mining's regulatory standards for addressing abandoned mine lands.

2011 **Alternate Pavement Type Bidding**: on behalf of the Pennsylvania Department of Transportation, Bureau of Maintenance and Operations; Expert analysis of alternate pavement type bidding policies as implemented on highway design projects in Pennsylvania.

Publications

Streambank Stability: Modeling Channel Evolution and Pollutant Transport in an Urban Stream; Ruth A. SItler; Pennsylvania State University, Masters Paper; Dec 2010.

Geographic Variability of Rainfall Erosivity Estimation and Impact on Construction Site Erosion Control Design; Shirley E. Clark, Aigul Allison, and Ruth A. Sitler; *Journal of Irrigation and Drainage Engineering*; American Society of Civil Engineers; July 2009.

Special Experimental Project No. 14 (SEP-14) Alternate Pavement Type Bidding Initial Report; Pennsylvania Department of Transportation and the Federal Highway Administration; Feb 2011.

Porous Asphalt Pavement: 20 Years and Still Working, Michele Adams, Published in Stormwater Magazine May/Jun 2003

Presentations and Conference Proceedings

2011

Sep Low impact Development Symposium; Ruth A. Sitler; "Impact of the Rainfall Event Method on the Water Capture Quantity Efficieny of Bioretention Devices"

May 2011 World Environment & Water Resources Congress; Ruth A. Sitler and Shirley E. Clark; "Impact of Bioretention Design of the Calculation Method for the 95th Percentile Rain Event"

2009

Mar "Act 167 Stormwater Management;" Harrison City, PA

May 2009 World Environment & Water Resources Congress; Christine Y. Siu, Shirley E. Clark, Ruth A. Sitler and Katherine Baker; "Looking Upstream and Into the Watershed for the Big Picture of Stream Health"

June "Act 167 Stormwater Management – Municipal Implementation Models;" Mercer, PA

July "Introduction to Hydrologic Modeling with HEC-HMS;" Harrisburg, PA
"Building a Project and Running a Simulation with HEC-RAS;" Harrisburg, PA

Oct 2009 Pennsylvania Stormwater Management Symposium; Ruth A. Sitler, Aigul Allison, and Shirley E. Clark; "Geographic Variability of Rainfall Erosivity Estimation and Impact on Construction Site Erosion Control Design"

2008

Feb "Small Watershed Hydrology Modeling with WinTR-55;" Middletown, PA
"AutoCAD;" Middletown, PA
Mar "Erosion Control and NPDES Permitting;" Middletown, PA
Apr "Introduction to HEC-RAS;" Middletown, PA
"HEC-HMS: The Hydrologic Engineering Center's Hydrologic Modeling System;" Middletown, PA
May "Planning to Protect Water Resources: Stormwater Management;" Hershey, PA
Sep "Understanding the Regulatory Environment: DEP Headwaters Initiatives and Stormwater BMPs;" Monroeville, PA
Oct "Integrated Water Resource Planning through Act 167;" Harrisburg, PA
Nov "Stormwater Management: Act 167 and Its Implementation;" Harrisburg, PA

2007

Mar "Engineering Overview of Erosion Control and NPDES Permitting in Central Pennsylvania;" New Cumberland, PA
Oct 2007 Pennsylvania Stormwater Management Symposium; Ruth A. Sitler and Shirley E. Clark; "Streambank Stability: Modeling Channel Evolution and Pollutant Transport in an Urban Stream"

NIEK VERAART, AICP, ASLA Project Manager

Mr. Veraart is vice president with LBG with more than 20 years of diverse experience in environmental planning, including EIS in accordance with NEPA, SEQRA and CEQR and other environmental statutes. His environmental planning assignments have encompassed a wide range of projects, including transportation infrastructure (airports, highways, ports, rail/transit) industrial facilities (solid waste management, energy, water and wastewater facilities), large-scale development projects (residential, commercial, mixed use, recreational and transit-oriented development), ecological and sustainable development (watershed management, LEED compliance, waterfront restoration, wetland banking) and cultural resources (memorials, tourist attractions, national parks). He is familiar with regulatory requirements at federal, state, and local levels and has integrated such requirements on multilevel environmental documents, including such high-profile assignments as the World Trade Center Memorial and Redevelopment GEIS. Mr. Veraart is especially familiar with construction impacts and assisted federal and state agencies with the development of Environmental performance Commitments (EPCs) for the rebuilding of Lower Manhattan. Mr. Veraart is familiar with upstate watershed issues through his completion of several SEQRA assignments, including an EIS for the Hackensack River in Clarkstown, New York; infrastructure improvements for the Bear Mountain Bridge (for NYSDOS); and the EIS for Kensico Watershed Water Pollution Control Program (for NYCDEP). Mr. Veraart's experience with third-party EIS review is extensive and includes multiple EISs for US Army Corps of Engineers, EIS review for local public interest environmental organizations and for the New York State Public Service Commission.

Several of the projects led by Mr. Veraart have received prestigious state and national awards. Mr. Veraart has presented at national conferences on subjects of environmental planning and his research contributions in the transportation and environmental planning fields have been published by the National Academy of Sciences, Transportation Research Board.

FIRM Louis Berger Group

EDUCATION
- MS, Regional Planning and Land Planning
- BS, Land Planning and Landscape Architecture

REGISTRATIONS / CERTIFICATIONS
- American Institute of Certified Planners
- American Society of Landscape Architects
- American Society of Civil Engineers, Affil.
- International Association for Impact Assessment

YEARS EXPERIENCE 24
YEARS WITH FIRM 16

RELEVANT PROJECT EXPERIENCE

Lower Manhattan Development Corporation (LDMC), GEIS for World Trade Center Memorial and Redevelopment Plan (SEQRA, NEPA EIS), New York, New York. Project director. Mr. Veraart directed LBG's work for the WTC GEIS, which was co-prepared by LBG with another consulting firm. Under Mr. Veraart's direction, transportation analyses were conducted for the redevelopment of the World Trade Center site and construction scenarios were developed for input into the Traffic, Air Quality and Noise analyses. The GEIS process for this high-profile; complex project was completed within a record time of 12 months from the start of environmental review. Mr. Veraart also directed noise, infrastructure, utilities as well as issues of cumulative impacts.

US Army Corps of Engineers New York District, Third-Party EIS, Meadowlands Mills Regional Mall, Bergen County, New Jersey. Project director. Mr. Veraart was Task manager for the independent third-party review of the developer's EIS and preparation of a federal FEIS and Section 404(b) Permit Alternatives Analysis for the development of a 600-acre site for the construction of a mixed use regional mall, office and recreation complex, located three miles from New York City. The project would involve the filling of approximately 200-acres of wetlands and extensive wetland creation and enhancement.

US Army Corps of Engineers New York District, Meadowlands Comprehensive Restoration Implementation Plan Programmatic Environmental Impact Statement, New Jersey. Provided QA/OC review of the Programmatic Environmental Impact Statement (PEIS) for the Meadowlands Comprehensive Restoration Implementation Plan (MCRIP). The PEIS provides an evaluation of environmental, social and economic issues and alternatives to achieve project goals and objectives, while avoiding/minimizing adverse impacts, providing the USACE with the necessary NEPA compliance documentation for MCRIP implementation. The PEIS is a comprehensive document that considers a number of related actions proposed in the MCRIP, including cumulative, direct, and indirect impacts.

New York City Department of Environmental Protection, Kensico Watershed Water Quality Sustainable Management Plan EIS, Westchester County, New York. Project manager. The EIS evaluated the beneficial effects on water quality resulting from several alternative measures, including the development of stormwater Best Management Practices (BMPs), such as wetland basins, streambank stabilization and waterfowl management. Pollutant reductions were subsequently modeled for each of the streams and subwatershed discharging into the Kensico Reservoir. Transport of contributing pollutants within the reservoir and to the water intakes was then modeled. In addition to the evaluation of the effectiveness of various program alternatives, their impact on the environment was assessed,

including socioeconomic and ecological impacts.

Metropolitan Transportation Authority New York City Transit, Fulton Street Transit Center NEPA EIS, New York, New York. Project director. Directed the preparation of the FEIS and Section 4(f) for the $1.4B federally funded Fulton Street Transit Center (FSTC) in Lower Manhattan. Mr. Veraart supervised the approach to alternatives analysis and cumulative effects analysis and supervised preparation of technical assessment of environmental impacts, including traffic and transportation, air, noise, socio-economic analyses and the analysis of adaptive reuse of the historic Corbin Building in Lower Manhattan. A key aspect of the analysis was the assessment of cumulative impacts of the FSTC and other Lower Manhattan Recovery Projects. Mr. Veraart presented the analysis of cumulative construction in Lower Manhattan to a National Panel of government agencies under auspices of the FTA.

US Department of Agriculture, Final Environmental Impact Statement (FEIS - SEQRA, NEPA) Gull Hazard Reduction Program, JFK International Airport, Jamaica, New York. Project manager. Managed the preparation of the SEQRA/NEPA EIS for the implementation of the Gull Hazard Reduction Program at JFK International Airport in New York City.

Parcel B EIS Third-Party Review and Environmental Support Services, Purchase Environmental Protection Association, Purchase, New York. Project manager. Analyzed SEQRA documentation submitted for an office development in Purchase, New York. The expert review team lead by Mr. Veraart reviewed all relevant aspects of the analyzed by the developer and identified numerous deficiencies and inaccuracies in the environmental documentation, including historic resources (impacts on Olmstead landscapes and resources listed on the State/National Register of Historic Places), flooding and stormwater management, incompatibility with zoning regulations, density inconsistencies, traffic safety and congestion issues, ecological impacts and direct and indirect wetland impacts.

Dormitory Authority of the State of New York (DASNY), Chenango Countywide 911 Communications Upgrade EIS, Chenango County, New York. Project Director. Led the preparation of the SEQRA EIS. The project included a GIS-based viewshed analysis of tower visibility. The viewshed analysis included the identification of sensitive resources (e.g. parks and historic areas) within five miles of each tower. The project objective was to improve emergency services communication capabilities through the construction of six radio communication antenna towers and ancillary infrastructure, and upgrades to facilities at an additional three sites

US Army Corps of Engineers New England District, South Coast Rail Project Third-party NEPA EIS (in progress), Massachusetts. Project manager. Mr. Veraart is managing the preparation of an Alternatives Analysis and NEPA EIS for new 60-mile transit service between Boston and the south coast of Massachusetts, including New Bedford and Fall River. Alternatives being evaluated include Bus Rapid Transit and rail. Key impact areas addressed included wetlands, water resources, threatened and endangered species, noise and vibration and coordination with Native American tribes.

Township of Randolph, Third-Party Environmental Review and Site Suitability Analysis Services, Randolph, New Jersey. Project manager. Conducted an independent third-party review of the environmental documentation for the 154-acre Nitti Mountain development project in the Township of Randolph, New Jersey. The review assessed all applicable resources including soils, geology, wetlands, hydrology, slopes/engineering, ecology; land use and zoning, landscape and visual, traffic/circulation and access, cultural resources and socioeconomic impacts. The report provided comments and recommendations regarding technical methodologies, data gaps and data quality, compliance with applicable regulations and appropriateness, projected cost and feasibility of proposed mitigation measures.

City of New City, New York, FEIS, Hackensack River Natural Area Improvement and Flood Management Project, Clarkstown, New York. Project director. Mr. Veraart directed the preparation of the FEIS for flood control measures in the Hackensack River. Flood control measures include the construction of backwater prevention berms, dredging of river sediment and widening of the river in order to improve flow.

NYS Bridge Authority, EA (SEQR) Bear Mountain Bridge Rehabilitation, Bear Mountain,

New York. Project director. Directed environmental permitting and regulatory issues for rehabilitation of the Bear Mountain Bridge across the Hudson River.

Port Authority of New York and New Jersey, Newark Liberty International Airport, Terminal A NEPA Draft Environmental Assessment. Newark. New Jersey. Project manager. Preliminary Environmental Assessment for construction of a new Terminal A facility, including a 1.3 million sf. airport terminal building, surrounding site conditions, including streams and wetlands, roadways and airside facilities. The EA was prepared in close coordination with sustainable planning and design efforts ongoing concurrently towards a LEED certified facility.

LMDC and the National September 11 Memorial & Museum, Pedestrian Simulation Modeling - World Trade Center (WTC) Memorial, New York, New York. Project director. Oversaw the development of origin/destination projections for pedestrian travel patterns on the World Trade Center (WTC) Memorial including the plaza, visitor's center, and museum and the entire WTC Site for the opening year and stabilized year of the WTC Memorial on both a weekday and Saturday. Also developed assumptions for the development program, pedestrian profiles, pedestrian itineraries, and site demand projections. The projected pedestrian movements were modeled to determine if adequate space would be provided for pedestrians based upon the site design and site plan

State University of New York at Binghamton. New Student Housing, State. Town of Vestal, Broome County, New York. Project Director. Directed the preparation of a SEQRA EAF and Supplemental Studies for replacing the 40 years old Newing and Dickinson residence buildings with new buildings to accommodate approximately 3,000 students on the East Campus of Binghamton University. The impact assessments focused on a matrix of potentially affected environmental resources, including storm water/wastewater infrastructure, threatened and endangered species, air quality, and noise.

American Marine Rail, LLP, Dredge Permitting, SEQR Environmental Assessment Statement. And Facility Plan Development. American Marine Rail Intermodal Transfer Terminal, Bronx, New York. Project director. Managed the development of facility layout and directed preparation of permits and state and city environmental regulatory review for a 5,200 tons-per-day intermodal barge-to-rail facility solid waste transfer station. Mr. Veraart supervised the preparation of a Title 6 NYCRR Part 360 Solid Waste permit application to the New York State Department of Environmental Conservation (NYSDEC), a Joint Tidal Wetland Permit from the NYSDEC and the USACE and air quality compliance, as well as compliance with other regulatory requirements**.**

South Jersey Transportation Authority (SJTA) Alternative Energy Vehicle Deployment Plan. Project Director. Directed the preparation of an AEV deployment plan for SJTA, pursuant to the SJTA Alternative Energy Management Plan, prepared by The Louis Berger Group for SJTA. Specific four areas included evaluation of Alternative Energy sources for the SJTA fleet and operations, as well as users of SJTA facilities. Alternative energy sources evaluated include electric, Compressed Natural Gas (CNG), biodiesel and hydrogen.

National September 11 Memorial, Economic Impact of National September 11 Memorial. Project director. Directed the study to analyze impact of the National September 11 Memorial operations on the economy of New York City, New York State and the U.S. Impacts are driven by Memorial operational expenditures, employee household spending and visitor spending. Assessed the effect of the Memorial on Lower Manhattan in terms property tax revenues and business revenues.

NYCDOS, Draft Environmental Impact Statement (DEIS - SEQR, CEQR), Fresh Kills Landfill, Staten Island, New York. Project director. Executive responsibility for the preparation of the DEIS for the Fresh Kills Landfill on Staten Island. For the continued operation of the 2,200-acre landfill, NYCDOS applied for a NYCRR Part 360 Permit for a solid waste management facility from the New York State Department of Environmental Conservation (NYSDEC). For this purpose, the NYCDOS submitted an EIS pursuant to both State Environmental Quality Review (SEQRA) and City Environmental Quality Review. The DEIS was deemed complete by NYSDEC prior to the City's decision to close the Fresh Kills Landfill.

RAED EL-FARHAN, PHD Principal-in-Charge

Dr. EL-Farhan, vice president of LBGs science and water resources division, has more than 20 years of experience as a consultant, professor, and university researcher. His areas of expertise include water resources, ecosystem restoration, stormwater management, water and wastewater treatment systems, water quality permitting and compliance, aquatic chemistry, and the fate and transport of contaminants in the environment. Dr. EL-Farhan has used this diverse expertise in support of EPA headquarters and its regional offices in their BEACH, EMPACT, and TMDL programs, where he has characterized, assessed, and modeled water quality; wrote and reviewed technical reports; and prepared training materials and workshops. He has worked extensively with various states to provide water resources planning services throughout the Mid-Atlantic region, and continues to support the EPA's Assessment and Watershed Protection Division through the Technical Support for the National Watershed Protection Program. Dr. EL-Farhan is working on multiple assignments with U.S. Army Corps of Engineers, Institute for Water Resources (USACE IWR), Engineer Research and Development Center (ERDC), Districts, Headquarters, and Assistant Secretary of the Army (CE) to provide technical review of feasibility studies, conduct facilitations at USACE strategic sessions, assist the USACE with development of quality of life metrics, evaluate the USACE model certification process, and evaluate and certify models. Dr. EL-Farhan is a member of the American Water Resources Association and participates in national dialogues related to water resources issues. He also serves on the planning committee of the National Conference on Ecosystem Restoration (NCER) where he has worked alongside many of the USACE restoration experts.

FIRM Louis Berger Group

EDUCATION

- PhD, Environmental Engineering
- MS, Environmental Engineering
- BS, Civil Engineering

YEARS EXPERIENCE 21
YEARS WITH FIRM 10

RELEVANT PROJECT EXPERIENCE

USACE Kansas City, Project Initiation and Planning for Programmatic EIS for the Missouri River Recovery/Restoration Plan and the Public Relations Strategy and Internal Communication Plan Needs Assessment for the Missouri River Recovery Program. Director. Dr. EL-Farhan worked closely with the project manager to coordinate the technical leads, experts, academics, and subconsultants. He not only provides management, but also technical support. He is providing technical support and is responsible for the development of the Research Compendium that will serve as the scientific guideline and basis during the alternatives development phase of the project. Also, Dr. EL-Farhan is assisting with the development of the public outreach and communications strategy and plan for implementation for the Missouri River Recovery Program. This includes both an external public relations strategy and an internal communications plan.

USACE Baltimore, Anacostia River Watershed Restoration Plan. Program manager. Managed a comprehensive watershed restoration plan for the Anacostia River Watershed; its objective is to produce a systematic 10-year restoration plan for environmental and ecological restoration within the entire watershed to mitigate the impact of stormwater runoff to the Anacostia River watershed. The plan was conducted under the USACE General Investigations Program. The study was authorized in a resolution of the Committee on Public Works and Transportation, U.S. House of Representatives.

USACE IWR, Analytical and Professional Support Services. Program manager for this $25 million, five-year contract that provides technical and analytical support services that are generally not available within USACE, including the following principal areas: program management, water resources, environmental protection and restoration, navigation, information systems, and homeland security. Under this contract and Dr. EL-Farhan's leadership, LBG is providing technical review of feasibility studies, conducting facilitations at USACE HQ strategic sessions, assisting USACE with development of quality of life metrics, evaluate the USACE model certification process and certifying models.

USACE Mobile District IDIQ for Environmental Studies for BRAC Actions. Program manager. Under $6 million IDIQ contract, Dr. EL-Farhan oversees overall project management, subcontractor management, project scheduling, quality assurance and control, deliverable production, project accountability to USACE Mobile, and maintains the administrative record. Currently working on environmental, engineering, and planning services in preparation of Phase II of the feasibility study and EIS for the ecosystem restoration and flood damage reduction for the 23 square-mile Upper Turkey Creek Basin in Kansas. Scope includes engineering analysis for the plan formulation to accomplish flood protection, environmental restoration, and improve water quality and recreational facilities.

USACE Baltimore, IDIQ for Planning Projects, Various Locations. Program manager. Under $5 million IDIQ contract, LBG is managing multiple task orders, preparing siting and facility studies and other planning documents. Specifically, Dr. EL-Farhan has worked on Potomac

Park Levee–EA and Section 106 project, for design and construction of an improved flood control project within the National Mall and Constitution Gardens in Washington, DC, to address the potential impacts to cultural and environmental resources. Also includes St. Martin Ecosystem Restoration–assisted in the evaluation of the feasibility study for aquatic ecosystem restoration in the St. Martin River Watershed in Maryland, under the authority of Section 206 of WRDA.

EPA Assessment and Watershed Protection Division, Technical Support for the National Watershed Protection Program. As program and project manager, developed dozens of watershed TMDL studies nationwide and has prepared training materials and conducted workshops. For these projects, conducted source assessment and watershed characterization to support watershed simulation and development of allocations. Presented TMDL results at a series public meetings. The Bayou Lafourche TMDLs, Louisiana included a comprehensive water quality monitoring plan, developing and submitting a QAPP for EPA's approval, setting up and calibrating Louisiana's QUAL2E model, and calculating the TMDL for the bayou.

Review of the Upper Mississippi River Illinois Waterway Feasibility Report. To help ensure the adequacy of this recommendation to Congress, Dr. EL-Farhan and the LBG team provided a review of the UMRS Chief's Report, the Rock Island District Commander's Feasibility Report, the NRC Reports on the UMRS, and related documents. The purpose of the review was to evaluate the actions proposed by the Chief of Engineers and District Commander in relation to external reports by the NRC and other parties, as well as prior Assistant Secretary of the Army (CW) correspondence to OMB to determine potential courses of action for the Assistant Secretary of the Army (CW) in transmitting his report to OMB and the Congress. The LBG report highlighted known and unknown information relevant to the ability to recommend an action to Congress, noted any deficiencies in needed information and recommended an appropriate course of action.

Transportation Research Board (TRB) of the National Academies. Senior technical reviewer. Dr. El-Farhan serves as a senior technical reviewer for the Transportation Research Board of the National Academies. He is responsible for reviewing documents and providing recommendations. Dr. El-Farhan will be reviewing papers for consideration as part of the program for the TRB 87th Annual Meeting in January 2008 and publication in the Transportation Research Record.

EPA Region 3, pH TMDL for Buckhannon River, West Virginia. Served as technical support for TMDL development for Acid Mine Drainage. Screened the available water quality data for the Buckhannon River to determine the frequency of water quality standards violation of pH and heavy metals. Reviewed models and methods applicable for predicting instream pH in streams. Developed a mass balance model based on inflow of alkalinity and acidity to predict the instream pH of the Buckhannon River.

HOPE LUHMAN, PHD, RPA Cultural Resources

Dr. Luhman manages LBG's New England and Northeast cultural resource operations from the Albany, New York, office. She is responsible for all archaeological, architectural, and historic preservation planning projects involving historic and precontact resources, as well as general business development. Dr. Luhman coordinates interdisciplinary and multitask studies; interfaces with clients and subconsultants; participates in public outreach and education programs; maintains project schedules; evaluates budgets; prepares technical reports, agreement documents, and special exhibits; and provides expert witness testimony.

FIRM Louis Berger Group

EDUCATION

- PhD, Anthropology
- MA, Anthropology
- MA, Social Relations
- BA, Anthropology

REGISTRATIONS/ CERTIFICATIONS

- Accredited by the Register of Professional Archaeologists

YEARS EXPERIENCE 28
YEARS WITH FIRM 16

RELEVANT PROJECT EXPERIENCE

Immigration and Naturalization Service (INS), Phase I and II Archaeological Survey, INS Border Patrol Station, St. Lawrence County, New York. Principal investigator.

GSA Northeast and Caribbean Region, Photographic Documentation, Phase IB Archaeological Survey, and Data Recovery Investigations, Proposed U.S. Courthouse, Buffalo, Erie County, New York. Project manager/principal investigator.

New York Army National Guard, Cultural Resource Surveys: New York Army National Guard (NYARNG). Project manager/principal investigator. Projects have included Phase IA archaeological surveys for the Rome, Lockport, Jamestown, Dunkirk, Cortland, and Dryden armories; Phase IA and IB surveys for the Walton, Kingston, Leeds, Latham, Orangeburg, Geneseo and proposed Queensbury armories; Phase IB survey for the Auburn Armory; and Phase II and III archaeological investigations for the Kingston Armory.

PARS Environmental for 77th Regional Readiness Command, Phase IB Archaeological Survey, Kerry P. Hein United States Army Reserve Center, Town of Shoreham, Suffolk County, New York. Project manager/principal investigator.

PARS Environmental for 77th Regional Readiness Command, Section 106 Compliance, Rocky Point/Brookhaven Nike Missile Launch Facility, Shoreham, Suffolk County, New York. Project manager/principal investigator.

77th Regional Readiness Command, Phase IA Archaeological Surveys, New York and New Jersey. Project manager/principal investigator.

U.S. Army Corps of Engineers (USACE) Mobile, Phase I Archaeological Survey, Fort Totten BRAC, Queens County, New York. Project manager/principal investigator.

Engineering Field Activity Northeast, Naval Facilities Engineering Command (NAVFAC), Archaeological Monitoring, Palmer Hall Geothermal Loop Field, U.S. Merchant Marine Academy, King's Point, New York. Project manager/principal investigator.

U.S. Military Academy, Cultural Resources Support, Family Housing, USMA, West Point, New York. Project manager/principal investigator.

Engineering Field Activity Northeast, NAVFAC, Archaeological Monitoring, Barry Hall Geothermal Loop Field, U.S. Merchant Marine Academy, King's Point, New York. Principal investigator.

Denver Service Center (DSC), Direct Labeling of Artifacts Recovered from the Archeological Excavations Conducted at Fort Stanwix National Monument for Willett Center Construction, Oneida County, New York. Project manager.

Phase I Archeological Survey, Proposed Mongaup Interpretive Center, Upper Delaware Scenic and Recreational River, Lumberland, Sullivan County, New York. Project manager/co-principal investigator and cultural resource task leader.

Archeological Survey for Roosevelt Farm Lane Rehabilitation Project, Home of Franklin Roosevelt National Historic Site, Hyde Park, Dutchess County, New York. Project manager.

Archeological Survey for the Construction Staging, Sediment Dewatering, and Sediment Dispersal Areas, Val-Kill Pond Restoration Project, Eleanor Roosevelt National Historic Site, Hyde Park, Dutchess County, New York. Project manager.

DASNY, Report on the Phase II and III Archaeological Investigations, The DASNY Site, 515 Broadway, Albany, Albany County, New York. Project manager.

DASNY, Phase IA Newing College Dormitory, State University at Binghamton, Broome County, New York. Project manager.

DASNY, Phase IA Archaeological Survey, Chenango Countywide 911 Communications System Upgrade, Chenango County, New York. Project manager.

Ammann & Whitney, and New York State Bridge Authority, Cultural Resource Services, Bear Mountain Bridge Cable Strengthening Study, Rockland and Westchester Counties, New York. Project manager.

Ammann & Whitney, Phase IA Cultural Resource Sensitivity Assessment, Proposed Amsterdam Pedestrian Bridge, City of Amsterdam, Montgomery County, New York. Project manager.

EBI Consulting, Cultural Resource Services for Wireless Carriers, New England. Contract and project management/principal investigator. On-call contract for performance of cultural resource surveys in New York, Massachusetts, New Hampshire, Vermont, Connecticut, Rhode Island, and Maine. Archaeological desk reviews, archaeological resource assessment reports, and reconnaissance/intensive surveys have been conducted throughout New York, Massachusetts, New Hampshire, Vermont, Connecticut, and Rhode Island.

USACE New England, Review of Cultural Resource Investigations, South Coast Rail Project, Southeast Massachusetts. Project manager/principal investigator.

New York State Education Department (NYSED)/New York State Department of Transportation (NYS DOT), Cultural Resource Services. Contract manager. Five-year contract (beginning 2007) to provide cultural resource services primarily associated with NYS DOT Regions 8-11, but may also include other state agency undertakings. Project-specific studies for all phases of archaeological investigations and architectural resource surveys. To date, 28 task orders received; four examples of completed projects are listed below.

- Cultural Resource Reconnaissance Survey, Site Examination and Data Recovery Plan, Shaker/Powell Hotel Site, Route 155 and Old Niskayuna Road Intersection Improvements, PIN 1132.15.101, Town of Colonie, Albany County, New York. Project manager and principal investigator.
- Archaeological and Architectural Reconnaissance Survey, Gorham Street Bridge and Approach Removal, PIN 3805.50.101, Village of Waterloo, Seneca County, New York. Project manager and principal investigator.
- Reconnaissance (Phase I) Survey, Republic Airport Development Aircraft Hangar, PIN 0903.55.101, Town of Babylon, Suffolk County, New York. Project manager and principal investigator.
- Cultural Resource Reconnaissance Survey, Jericho Turnpike, PIN 0042.27.121, Towns of Huntington and Smithtown, Suffolk County, New York. Project manager and principal investigator.

EDWARD SAMANNS, PWS, CE Aquatic Ecology

Mr. Samanns is the director of environmental sciences at LBG with more than 20 years of experience managing environmental investigations for a variety of projects and clients. Mr. Samanns specializes in ecological restoration/mitigation and related topics including stream and wetland ecology, permitting, threatened and endangered species studies, invasive species management, and NEPA compliance. Mr. Samanns serves as the project manager/director for several environmental and restoration contracts for public sector clients and was responsible for preparing data collection and analysis protocols, developing and implementing vegetative and hydrology monitoring methodologies, and developing habitat restoration designs. Mr. Samanns is a key member of LBG's ecological restoration unit, a unique assemblage of key scientists and engineers that have been combined to conduct restoration projects including wetland mitigation banks, endangered species habitat enhancement, coral reef creation, and tidal marsh restoration. He was the principal investigator and author of NCHRP Synthesis 302 Mitigation of Ecological Impacts (2002), is currently conducting research for NCHRP on Habitat Fragmentation, and has published/presented several papers on wetland mitigation and wildlife crossings. Mr. Samanns is also a co-author of the USACE, Waterways Experiment Station, Engineering Specification Guidelines for Wetland Plant Establishment and Subgrade Preparation (1998). Mr. Samanns also performs QA reviews of technical reports and restoration designs and provides independent research on environmental topics for clients.

FIRM Louis Berger Group

EDUCATION
- MS, Geography
- BS, Biology

REGISTRATIONS/ CERTIFICATIONS
- Professional Wetland Scientist
- Certified Geologist

YEARS EXPERIENCE 25
YEARS WITH FIRM 23

RELEVANT PROJECT EXPERIENCE

County of Rockland, Minisceongo Creek Nor'easter Repair Project, Rockland County, New York. Project manager. Responsible for overseeing the wetland and stream delineation for the project area and preparation of the Environmental Investigation Report. Also evaluated project for compliance with NEPA CATX requirements of FEMA and coordinated with project engineers to assess project alternatives to stabilize an area of mass wasting and slope failure, protect existing infrastructure from river erosion, re-establish fish passage, and establish self mitigating construction approach. Responsible for ongoing coordination of NYSDEC and ACOE permits for construction.

Marsh Resources, Meadowlands Mitigation Bank Phase 3, Carlstadt, New Jersey. Project director of the permitting, design and upcoming construction of a 60-acre tidal and freshwater wetland mitigation bank in the Hackensack Meadowlands. Responsibilities include federal and state permit application preparation and acquisition, banking instrument preparation, negotiation and approval by the interagency MIMAC, and site concept designs. Analysis has included assessment of on-site resources, functional value assessment, credit determination, innovative designs to minimize wetland fill and control invasive species, tidal data analysis and tide gate assessment. Planting plan also addressed potential treatments for acid soil conditions. Responsible for developing construction and planting plans as a design/build project employing marsh excavation and dredge methods to create enhanced tidal habitat of mud flat and low and high marsh interspersed by tidal channels and upland islands and freshwater forested wetlands.

New York Thruway Authority and NYSDOT, Stewart Airport Access Improvement, Wetland and Vernal Pool Mitigation Site Selection and Design. Project manager. Responsible for conducting a site selection and design study for the creation of 1.5 acres of vernal pool habitats within forested uplands to compensate for wetland habitat losses as requested by the NYSDEC. Evaluated physical features within project area leading to the identification of potential sites. Developed concept plans for each vernal pool site. Also responsible for the design of 15 acres of forested, scrub shrub and emergent wetlands at an off-site location. Prepared full plans and specifications to support bid documents. Additional task included preparation of a Biological Assessment for the Federal and State endangered Indiana bat along the project corridor, and coordination with the USFWS and NYSDEC.

PANYNJ, Goethals Bridge Replacement Project, Staten Island. Project supervisor. Responsible for overseeing the tasks related to the preparation of the natural resource components of a NEPA EIS and the preparation of environmental permits required for issuance of the Record of Decision by the US Coast Guard. Also supervising the wetland mitigation site selection and wetland mitigation design tasks that are necessary to support the preparation of a Mitigation Plan for the Corps permit application. Permit applications include addressing purpose and need, alternatives analysis, coastal zone consistency reviews, EFH assessments, and other topics.

USACE Baltimore District, Integrated Natural Resource Management Plan Environmental Support Services, 99th Regional Readiness Command. Project supervisor. Responsible for overseeing the preparation of an Invasive Species Management Plan and Endangered Species Management Plan as part of an INRMP for use on 184 properties in five states under the command of the 99th Regional Readiness Command. The invasive species management plan was developed to maintain compliance with EO 13112 Invasive Species and the Army Policy Guidance for Management and Control of Invasive Species. The endangered species management plan was updated to maintain compliance with the Endangered Species Act, Bald and Golden Eagle Protection Act, DoD Instruction 4715.3, and AR 200-3. The management plans address existing conditions and habitats, target species and appropriate management actions and estimated costs.

Molly Ann Brook Watershed Management Plan, Passaic County, New Jersey. Project director. Responsible for the coordination and completion of all field studies, meetings, workshops, report preparation, staffing, schedule and budget for this project. The project involves development of a Geodatabase as part of a watershed characterization effort that includes Rosgen stream reach classification, USGS Visual Assessments, and point source locations. Baseline analysis also included collection of hydrologic data and development of stream rating curves, incorporation of fecal coliform and other water quality data, benthic macroinvertebrate data, and assessments of potential nonpoint pollution sources within watershed. Prepared and conducted two public workshops to educate and gather information from interested citizens and public officials. Developed a prioritized list of effective BMP's and prepared a concept design and constructability assessment of the six best candidates for installation.

PANYNJ, Environmental Assessment, Newark Airport, Newark and Elizabeth, New Jersey. Environmental scientist. Responsible for overseeing the preparation of natural resource sections of an FAA Environmental Assessment (EA) for the expansion and modernization of Terminal A at Newark Liberty International Airport. Provided oversight of field investigations and baseline conditions analysis. In addition, provided technical input on options to minimize and mitigation wetland and open water impacts on-site through the use of innovative design options.

Brookhaven Science Associates and US Department of Energy, Peconic River Restoration Project, Brookhaven National Laboratory, Suffolk County, New York. Project manager. Responsible for the development and implementation of a Wetland Restoration Design as part of a three phase remediation of 14,700 linear feet of contaminated stream and freshwater wetlands. Also prepared and obtained NYSDEC wetlands equivalency permits, and long term monitoring plan. Project included developing a habitat assessment for the state threatened Banded Sunfish, developing and implementing protocols for the collection and transplanting of wetland plant material into restored wetlands, and collection and transplanting dormant trees using tree spades.

NYSDOT, Term Agreement for Ecological and Water Resource Studies, and Training. Project manager. Responsible for managing three consecutive four-year on-call services term agreement to provide wetland and water services to NYSDOT Regions 8, 10 and 11, and other upstate regions. Services performed include the delineation of state and federal regulated wetlands, wetland functional assessments, wetland permitting support under the New York State Freshwater Wetlands Act and Section 404 of the Clean Water Act, stream assessments and restoration design, and water quality assessments modeling. Additional services include providing training to NYSDOT staff, evaluating alternative alignments to avoid, minimize and reduce wetland impacts, evaluate wetland mitigation sites, and conducting and preparing wetland mitigation monitoring reports for submission to USACE/NYSDEC. Over one hundred task orders have been completed.

Federal Bureau of Prisons, NEPA EA/EIS Preparation for Proposed Federal Correctional Facilities Nationwide. Team leader. Conducting wetland delineations, wetland assessments, biological inventories, and impact assessments for multiple EAs and EISs for proposed federal prison facilities. Also performed Section 404/State 401 permitting and mitigation site selection and design for several of the projects. Managed staff, subconsultants, and report preparation to complete tasks on time and on budget. Projects are located in over fifteen states and have required interaction with state regulatory agencies and USFWS.

LEO TIDD Noise, Land Use, Indirect and Cumulative Impacts

Mr. Tidd's work at LBG has been focused on conducting environmental analyses for proposed projects and preparing documents to demonstrate compliance with state and federal environmental laws and regulations. He has been lead author and editor of complex EISs required as a result of prior environmental litigation. On these projects Mr. Tidd serves as the primary author, synthesizing the work of various technical specialists into a logical and concise narrative that addresses regulatory compliance and ensures that the lead agency took the requisite "hard look" at environmental issues. In addition, he is responsible for technical environmental analyses on topics that include, noise, indirect and cumulative impacts, air quality, habitat fragmentation/edge effects, wetlands and water resources. Mr. Tidd has completed noise impact modeling for a new connector roadway to the Atlantic City International Airport in New Jersey, as well as comprehensive noise evaluations for off-road vehicle use at the National Park Service (NPS) at Yellowstone National Park and the Lake Meredith National Recreation Area. Mr. Tidd has prepared or contributed to the indirect and cumulative impact assessments for several projects where litigation on indirect and cumulative impact issues occurred in the past or is anticipated, including the Circ-Williston Transportation Project in Vermont, the I-93 Improvements Project in New Hampshire, the Gaston East- West Connector in North Carolina, and the Birmingham Northern Beltline in Alabama. Mr. Tidd is a contributing author of the Legal Sufficiency Criteria for Adequate Indirect Effects and Cumulative Impacts Analysis as Related to NEPA Documents report prepared for AASHTO Standing Committee on the Environment as part of NCHRP Project 25-25.

FIRM Louis Berger Group

EDUCATION

- MPA, Environmental Science and Policy
- BS, Environmental Studies

TRAINING

- Transit Noise and Vibration Impact Assessment, National Transit Institute, 2011
- Highway Traffic Noise: Basic Acoustics, National Highway Institute, 2011
- EPA and FHWA Particulate Matter Quantitative Hot Spot Analysis Training, 2011
- AERMOD Dispersion Modeling Training, Lakes Environmental, 2011
- EPA and FHWA MOVES2010 Training, 2010
- EPA and FHWA Draft MOVES2009 Training, 2009
- Introduction to Transportation Conformity, National Transit Institute, 2008

YEARS EXPERIENCE 6
YEARS WITH FIRM 6

RELEVANT PROJECT EXPERIENCE

Peninsula Corridor Joint Powers Board, Dumbarton Rail Corridor Noise and Vibration Study, California. Task manager. The Dumbarton Rail Corridor Project EIS is being prepared for a proposed new rail service on a corridor spanning San Francisco Bay connecting the existing Caltrain San Jose-San Francisco line alignment in Redwood City, San Mateo County to Newark, Union City and other cities in Alameda County. The noise and vibration study being prepared by Mr. Tidd includes short-term noise monitoring at sensitive receptor locations, train and grade-crossing bell noise impact assessment using Federal Transit Administration procedures, train horn noise impact assessment using Federal Railroad Administration's horn noise spreadsheet program, and a screening analysis of bus noise impacts using FHWA's Traffic Noise Model.

NPS, Yellowstone National Park Winter Use Plan EIS, Wyoming, Montana and Idaho. Planner. Mr. Tidd was the lead author of the EIS chapters addressing the impacts of various levels of snowmobile and snowcoach use on air quality and natural soundscapes as part of the Yellowstone Winter Use Plan Draft EIS. Mr. Tidd summarized the available monitoring data to describe existing conditions in the park, and coordinated extensively with the NPS Natural Sounds program that was responsible for developing the impact thresholds and detailed soundscapes modeling effort. One key challenge addressed by Mr. Tidd was identifying the potential for cumulative impacts to natural soundscapes from actions by others, including oil and gas development in the region, aircraft overflights, and population growth/land development.

NPS, Lake Meredith National Recreation Area Off-Road Vehicle Management Plan EIS, Texas. Planner. Mr. Tidd wrote the EIS chapter describing the existing condition of natural soundscapes within two ORV areas based on monitoring data of percent time audible and sound levels. Mr. Tidd also assisted NPS with the development of soundscapes impact thresholds for the various action alternatives under consideration in the management plan and prepared the soundscapes impact assessment. The purpose of the Lake Meredith National Recreation Area Off-Road Vehicle plan/EIS is to manage ORV use in the national recreation area for visitor enjoyment and recreation opportunities, while minimizing and correcting damage to resources.

South Jersey Transportation Authority, Atlantic City Expressway/Atlantic City International Airport Direct Connector Road Noise and Air Quality Studies, Egg Harbor Township, New Jersey. Task manager. Mr. Tidd prepared air quality screening analyses based on changes in level of service and traffic volumes to address Federal Aviation Administration and conformity requirements for a new roadway and interchange in Egg Harbor Township, New Jersey. Mr. Tidd also conducted traffic noise modeling for the project using TNM2.5 and prepared the traffic noise study technical memorandum. Mr. Tidd developed the noise impact criteria for this project based on FHWA and FAA regulations. The noise modeling effort involved 41 receptor locations. In addition, Mr. Tidd prepared GIS mapping illustrating the location of environmental justice communities in the project area using 2010 U.S. Census data.

Vermont Agency of Transportation (VTrans), Circ-Williston Transportation Project EIS, Chittenden County, Vermont. Deputy project manager. The Circ-Williston EIS is a "fresh look" at a transportation project that was stopped as a result of environmental litigation just prior to construction. Mr. Tidd was responsible for editing the EIS and technical reports, creation of a comment database tracking system and was the lead author of the responses to comments on the Draft EIS and Final EIS. Mr. Tidd coordinated extensively with the various technical discipline specialists and subconsultants involved with the project to ensure a comprehensive and legally sufficient environmental documentation. Mr. Tidd's technical accomplishments on this project have included a detailed analysis of wildlife habitat edge effects and fragmentation, a GIS-based wetland mitigation site search analysis, a project-level greenhouse gas emissions analysis, and a deicing salt loading analysis.

New Hampshire DOT, I-93 Improvements (Salem to Manchester) Supplemental EIS (SEIS), New Hampshire. Deputy project manager. Mr. Tidd was the lead author of the I-93 supplemental environmental impact statement (SEIS), which was prepared in response to a court order requiring analysis of the effects of induced population and employment growth on secondary road traffic and air quality. In addition to editing all components of the SEIS, Mr. Tidd was also responsible for several technical analysis tasks, including a regional emissions sensitivity analysis for ozone precursors, and a cumulative impact analysis assessing the aggregate consequences of the project combined with other reasonably foreseeable projects and forecasted levels of population and employment growth in Southern New Hampshire. The project involves widening I-93 from two-lanes to four-lanes in each direction for a distance of 20 miles between the Massachusetts state line and Manchester, New Hampshire.

USACE, South Coast Rail EIS, Massachusetts. Planner. As part of the third-party review conducted by LBG, Mr. Tidd was responsible for the preparation of technical memorandums reviewing proposed methodologies for assessing indirect and cumulative impacts, and greenhouse gas emissions for the South Coast Rail project. Mr. Tidd was also responsible for editing portions of the DEIS/DEIR, assisting with quality assurance reviews and addressing comments on draft documents.

North Carolina Turnpike Authority, Gaston East-West Connector Indirect and Cumulative Effects Study, North Carolina. Task manager. Mr. Tidd prepared a quantitative indirect and cumulative impact assessment for a proposed toll road extending from I-85 west of Gastonia in Gaston County to I-485 near the Charlotte-Douglas International Airport in Mecklenburg County. As part of this study, Mr. Tidd defined watershed-based study area boundaries and developed metrics to translate household and employment growth into indicators for environmental impacts, such as increases in impervious surface cover and loss of forest cover. Mr. Tidd was responsible for developing and implementing the GIS-based analysis methodology for this project, as well as preparing the final technical report.

DASNY, Chenango Countywide 911 Communications Upgrade EIS, Chenango County, New York. Planner. Assisted in preparation of the SEQRA EAF, scoping document and EIS. Responsible for a GIS viewshed analysis of tower visibility using the ESRI 3D Analyst extension. The viewshed analysis included the identification of sensitive resources (e.g. parks and historic areas) within five miles of each tower. The project objective is to improve emergency services communication capabilities through the construction of six radio communication antenna towers and ancillary infrastructure, and upgrades to facilities at an additional three sites.

DANE ISMART Transportation

Mr. Ismart has 28 years experience with FHWA and 11 years with LBG. While with the FHWA, he served in many capacities including area engineer, research engineer, urban planner, and intermodal team leader. As part of the Office of Environment and Planning, Mr. Ismart specialized in systems transportation planning, intermodal planning, traffic engineering, and policy. He is a nationally recognized expert in transportation planning and models, highway capacity analysis, access management, and site impact analysis. During Mr. Ismart's tenure with FHWA, he conducted and authored the materials for more than 400 short courses on quick response urban planning models, traffic operations, freight planning and models, highway capacity, innovative highway and transit finance, transportation and environmental planning, land use planning, access management, and site impact analysis.

FIRM Louis Berger Group

EDUCATION

- MS, Civil Engineering
- BS, Civil Engineering

YEARS EXPERIENCE 28
YEARS WITH FIRM 17

RELEVANT PROJECT EXPERIENCE

Walmart versus Historic Preservation Society of Civil War Battlefields, Orange County, Virginia. Expert witness. Served as an expert witness for the Historic Preservation Society on the traffic impacts of a proposed Walmart development in Orange County, Virginia on the Wilderness Civil War Battlefield.

I-93 SEIS. Technical analyst. Developed traffic forecasts by using the New Hampshire Statewide Traffic Forecasting Model. Various scenarios are being analyzed and the results are being used for determining how well the projects purpose and scope are being met. As part of this project, an estimate of the potential changes in land use and indirect impacts due to adding capacity to the I-93 corridor are being developed.

Intermodal Terminal Innovative Finance Study. Technical writer. Developed a case study for the NCHRP study evaluating innovative funding techniques for improving access to intermodal facilities. The case study was for the Port of Palm Beach's Sky Bridge over Route 1.

Virginia Research Council. Author and instructor. Developed a financial management of federal aid course for Virginia Research Council.

Highways for Life Leap Not Creep Innovation of Technology Course. Subject matter expert technical advisor and senior instructor. Developed technical material on the application of new innovative techniques for long lasting construction and construction techniques to reduce maintenance of traffic delays and construction impacts.

FHWA, Predictive Performance of Traffic Simulation Models. Project manager. Developed a series of case studies for FHWA to assist transportation planners and traffic engineers in applying traffic simulation models. The case studies included several applications of simulation models forecasting traffic during construction as well as after completion of the projects. A brochure and how-to manual for troubleshooting the application of the simulation models to better replicate actual travel conditions was developed.

FHWA, Access Management Primer and Video. Project manager. Developed the FHWA Primer and Videotape entitled, "Safe Access is Good for Business." The primer discusses in detail methods for improving access to business during construction of corridor access improvement projects.

National Highway Institute. Instructor. Certified NHI instructor for the Federal-Aid 101 Course, Access Management Course, Innovation of Technology Course, and the Highway Capacity Course.

Update of Federal-aid 101. Author. Revised the FHWA Federal-aid 101 Course Material. The material was updated to include the latest planning, finance, construction, and environmental requirements required by SAFTEA-LU. The material and curriculum are used to train FHWA personnel.

FHWA Bottleneck Initiative Workshops. Lecturer/ technical advisor. Conducted Regional workshops and created technical material for the FHWA Bottleneck Initiative. The presentation included techniques for identifying potential corridor bottlenecks due to recurring and non-recurring events and applying innovative solutions for maintaining traffic

and reducing delay.

FHWA, Operations CBU Task Order. Key technical task leader. Directed technical teams for a series of FHWA tasks orders involving intermodal planning and policy analysis, freight movements, ITS, and traffic operations.

University of Tennessee, Planning Courses. Instructor. Developed and conducted travel demand forecasting, site impact, access impact, and highway capacity courses for the University of Tennessee and the Tennessee Department of Transportation.

University of Maryland. Instructor and course developer. Developed and conducted site impact, access management, and highway capacity courses for the University of Maryland and the Maryland State Highway Administration.

Central Arkansas Regional Transportation Study. Project manager. Conducted an analysis of the 200-mile freeway system in central Arkansas. The study developed a series of recommendations for improving the freeway system. The study also includes a feasibility study of a fourth bridge crossing over the Arkansas River in Little Rock, Arkansas and a financial plan for funding.

Florida Department of Transportation. Project manager. Conducted a study to evaluate and develop recommendations for improvements to the NHS intermodal connectors of FDOT's District Six.

Klingle Road EIS, Washington, D.C. Traffic technical lead. Conducted the traffic analysis and forecast for the Klingle Road EIS. Using the MWCOG model the project estimated the traffic and traffic patterns if Klingle Road was repaired and open to traffic.

NPS Potomac Boathouse EIS, Arlington County, Virginia. Traffic technical lead. Conducting the traffic analysis to determine the traffic and parking impact for the construction of a new Boathouse facility on the Potomac in Arlington County.

Wisconsin Avenue and Military Road Phase 1 and 2 Corridor Studies, Washington, D.C. Technical director. Conducted a corridor study for the Wisconsin Ave. Corridor and the Military Road Corridor in Washington, D.C. The study developed a series of transportation improvement recommendations for improving the flow of traffic. The study included public meetings and an analysis of future land use development in the corridor.

Washington, D.C., Evacuation Planning Study. Technical model leader. Developed a system-wide traffic forecasting tool to be used in rerouting traffic during man-made and natural disasters that cause corridor or system-wide disruption of traffic.

DC Office of Planning, Washington, D.C. Comprehensive Plan. Model director. Applied the Washington DC COG model as part of the development and evaluation of the Comprehensive Transportation Plan Element.

SHRP 2 R11: Strategic Approaches at the Corridor and Network Levels to Minimize Disruption from the Renewal Process. Principal investigator. Leading the team to create the Work Zone Impact Strategy Estimation (WISE) tool and technical primer. Planning and Operations modules will assist in assessing strategies including economic impact across networks and corridors with user-defined or default value performance measures.

BRAC Bethesda Medical Traffic Study. Traffic engineer. Directing an effort to analyze the impact that the transfer of the Walter Reed staff and patients to the Bethesda Naval Center will have on the access points and internal traffic of the Bethesda Naval Center. A mitigation program to relieve future congestion on the Center is being proposed and developed.

Route 29 Corridor Study, Fauquier County, Virginia. Principal investigator. Analyzing and recommending a series of innovative corridor improvements for Fauquier County, Virginia. A report is being written and improvements such as roundabouts, directional left turns, and restricted access movements are being analyzed.

Kevin Heatley, LEED AP

Employment

2010 – current	Biohabitats, Inc., Baltimore, MD, Senior Scientist
2006 - 2010	Biohabitats Invasive Species Management, Inc., ISM Vice President
2005 - 2006	Penn State College of Technology, Williamsport, PA, Substitute Instructor, Natural Resource Management Department
2005 - 2006	Invasive Plant Control, Inc., Nashville, TN, Director of Development Northeast Region
1997 – 2005	ACRT Inc., Akron, OH, Senior Forester/Regional Manager
1984 – 1994	Bartlett Tree Experts, Lancaster, PA, Area Manager/Arboricultural Consultant

Education

Masters Environmental Pollution Control, Penn State University, Harrisburg, PA, 2006
B.S., Natural Resource Management, Cook College, Rutgers University, New Brunswick, New Jersey 1982

Professional Registration

Certified Arborist #PD-0029, 2000
LEED Accredited Professional for New Construction (USGBC), 2009

Experience

Mr. Heatley has over 20 years of experience in the environmental sector with an extensive background in ecosystem characterization, integrated vegetation management, invasive species suppression and community-based forestry. As a senior ecologist at Biohabitats, Mr. Heatley is responsible for technical and logistical oversight of restoration projects across the continental United States. His work has primarily focused upon the urban/rural interface and on incorporating green infrastructure into sustainable land use planning and management. An expert in the field of invasive species suppression, Mr. Heatley designed the first fully integrated invasive treatment prioritization model in the United States for Fairfax County, Va. He has successfully integrated resource valuation modeling into strategic and budgetary management plans for a variety of land management entities. He has also been instrumental in providing the conceptual design for a leading GIS-based vegetation management software system.

In addition to his technical expertise, Mr. Heatley is skilled at conducting entertaining and informative public speaking engagements and professional workshops. He has lectured on a variety of natural resource topics throughout the United States and the Caribbean.

Representative Project Experience

NPS Revegetation Eastern States IDIQ, Eastern US. Mr. Heatley successfully served as the Biohabitats project manager on a 2.5 million dollar National Park Service Revegetation IDIQ contract. He coordinated and lead project planning and technical assistance services on a wide variety of ecological restoration task orders including revegetation, invasive species control, plant procurement, seeding, plant protection efforts, marsh restoration, and site characterization. Biohabitats has subsequently been awarded a $20 million dollar follow-up contract for National Park Service revegetation services across the Eastern United States and the Caribbean. Mr. Heatley is currently the project manager and technical lead on this contract.

Burgundy Farm Country Day School Ecological Site Assessment, *Alexandria, VA*. Biohabitats Inc. performed an ecological assessment of the campus and developed recommendations for the sustainable use and conservation of the school's asset. Proactive identification of both ecological assets and landscape challenges enabled the School to cost-effectively integrate site ecology into the master planning process.

Fairfax County Parks Invasive Plant Site Prioritization Model, *Fairfax County, VA.* Biohabitats ISM developed a comprehensive response strategy and site treatment prioritization model as a decision-making tool to be used by the Park Authority to rank the relative value of different sites within their approximately 24,000-acre park system. Based on the principle of "protect the best first" the model shifted the focus in the parks system away from "acres treated" towards "acres restored," allowing the County to maximize the return on its investment in invasive plant control by assuring that treatment sites reflect both the core ecological and cultural values that exist.

Lehigh University, *Bethlehem PA.* Desiring to more fully understand potential atmospheric carbon mitigation opportunities on the college campus, Lehigh University contracted with Biohabitats to undertake an analysis of the direct sequestration and avoided emissions associated with the schools landscape tree cover. Utilizing US Forest Service models, Mr. Heatley performed a comprehensive inventory of 600 acres of naturalized forest and over 220 landscape trees. Information gathered was integrated into strategic recommendations for enhancing this forest benefit and achieving a sustainable level of forest canopy.

Duke University*, Durham NC.* Concerned about the need to understand the ecological processes occurring in a high-visibility, centrally-located stand of campus woodland, Duke University contracted with Biohabitats to undertake an ecological analysis and natural capitol valuation of the campus area known as "Chapel Woods". Mr. Heatley inventoried the vegetation, performed an assessment of the functional benefits, and developed a management plan focused upon forest sustainability. As a function of this effort, Mr. Heatley also performed invasive species suppression within the forest understory.

Valley Road Stream Restoration and Riparian Wetland Creation, *Hagerstown, MD.* Mr. Heatley provided technical recommendations and coordinated invasive plant species suppression in support of the Valley Road Stream Restoration project in Hagerstown, MD. Project involved restoration of an urbanized stream corridor and significant modification of a highly disturbed riparian plant community.

Reforestation Consulting & Invasive Species Suppression, *Rockville, MD.* In order to assure the success of a reforestation effort on a 220 acre tract in Rockville, MD., Fallsgrove Associates, a private development firm, contracted with Biohabitats ISM to oversee tree planting and invasive species suppression. Biohabitats ISM developed and implemented a sampling protocol assessing tree stocking levels and produced biannual reports on supplemental planting levels needed to assure adequate canopy cover. As a component of this effort Biohabitats ISM performed planting contractor coordination and oversight. Biohabitats ISM also created a phased, multi-year, invasive plant suppression strategy. After conducting a comprehensive evaluation of the percent cover for each of the invasive species present on the site, Biohabitats ISM created a target metric for measuring the effectiveness of invasive control efforts. Seasonally selective treatments are currently being undertaken by Biohabitats ISM.

Woodland Restoration of Episcopal High School Alexandria, *Alexandria, VA.* Driven by a desire to integrate a 35 acre woodland resource into the fabric of campus life, the Episcopal High School of Alexandria, Va. contracted with Biohabitats ISM to develop a sustainable campus forest management plan and implement invasive species suppression. This effort involved campus ecosystem characterization, functional benefits modeling, and stakeholder vision sessions. Botanical communities on campus were defined and their respective ecosystem services, in the form of air pollutant interception and carbon sequestration, quantified. Several action items identified during the plan development have subsequently been implemented by Biohabitats including; trail design and construction, ecotone modification, and invasive species suppression. Ecotone modification involved the development of a forest edge planting plan addressing issues of wind vectoring and regeneration. Invasive species interventions have been conducted during 2007 and 2008 in a phased approach designed to enhance native regeneration and minimize opportunities for additional invasive colonization of the woodland.

Episcopal High School, *Baton Rouge, LA.* Recognizing the need to integrate sustainable design principles into future development on their 40 acre campus, the Episcopal High School contracted with Biohabitats (in conjunction with NK Architects) to develop a new Master Plan for the school. Mr. Heatley coordinated Biohabitats participation and involvement in this interactive process. He was directly

responsible for developing recommendations and strategies addressing stormwater retrofitting, green infrastructure expansion, and natural capital valuation.

Missionary Ridge Noxious Weed Inventory and Treatment, *Durango, CO.* During the final year of a three year project, Mr. Heatley provided technical oversight and coordinated the GPS/GIS component of the Missionary Ridge invasive species mapping and suppression effort. As part of an adaptive management approach, data collection protocols were modified and additional field staff were hired and trained by Mr. Heatley.

Woodland Management Plan for Episcopal High School, *Alexandria, VA.* Located in the Washington DC metropolitan area, the 150 years of stable land ownership at Episcopal High School has resulted in a significant legacy woodland on the campus. Recognizing the inherent educational, recreational, and inspirational value of their forest, the school contracted with Biohabitats to develop an integrated woodland management plan. The development of this plan involved a GIS-based forest stand delineation, ecological characterization, invasive plant mapping, ecosystem benefits modeling, and stakeholder vision session. As the project manager, Kevin Heatley developed the final document which provides a framework for sustainable management of this green component of the school infrastructure.

Fort Detrick, *Frederick MD.* The US Army operates Fort Detrick on over 1,200 acres of property in Frederick MD. The mixed land use pattern and competing mission objectives create special challenges regarding natural resource management. To aid in understanding field conditions and assist in budgetary justification, Fort Detrick contracted with Mr. Kevin Heatley (in conjunction with Heartwood Consulting LLC.) to undertake a resource analysis and characterization. The primary components of this project included: a GPS Landscape Tree Inventory (with tagging), GIS Database Integration, UFORE Modeling of the Environmental Impact of Forest Stands, and a Five Year Management Plan (with economic tree valuation). Mr. Heatley in addition was contracted with Fort Detrick to undertake a carbon mitigation feasibility analysis. This project examined the potential to use green infrastructure in the mitigation of vehicular greenhouse gas emissions on the base.

Representative Project Experience Prior to Biohabitats

Atkins Arboretum, *Ridgely MD.* Encompassing 400 acres on the Eastern Shore of Maryland, Atkins Arboretum is a unique facility that highlights native plant communities. With strong educational and research objectives as the primary focus of its efforts, the Arboretum enlisted the aid of Kevin Heatley (ACRT Inc.) to develop and implement a GIS-based vegetation database. Mr. Heatley supervised all aspects of the project including; high resolution aerial photogrammetry, GPS mapping of plant communities, the establishment of a thematic research plot layer, and the construction of a multi-thematic, GIS-based, vegetation database.

Tree Preservation Specifications Manual for Association for Zoological Horticulture, *Allison Park, PA.* The Association for Zoological Horticulture, an organization representing the interests of botanists, horticulturalists, and landscape professionals involved with the management of vegetation in zoological parks, contracted with Mr. Heatley for the creation of a set of standard tree preservation specifications. This document was initiated in response to excessive canopy loss during infrastructure construction and renovation projects. It was designed to promote an integrated, comprehensive approach to tree conservation appropriate for vegetation management within the challenging environment of a zoological park. It also contains an extensive specifications section suitable for use as an attachment on construction contracts.

Villanova University Five-Year Canopy Management Plan, *Villanova, PA.* Mr. Heatley as the project manager provided high resolution aerial photogrammetry, GPS/GIS vegetation and infrastructure mapping, and database design, of approximately 250 acres of this historic campus located in Villanova, Pennsylvania.

Swan Point Cemetery Five-Year Canopy Management Plan, *Providence, RI.* Mr. Heatley as the project manager provided GPS/GIS vegetation and infrastructure mapping, “seamless” GIS providing a work tracking database, and budget information of over 300 acres of this historic cemetery located in downtown Providence, Rhode Island.

Professional Associations

Society of American Foresters
International Society of Arboriculture
Society of College & University Planners

Selected Publications, Technical Reports & Presentations

Greater Everglades Ecosystem Restoration Conference, Naples, Fl, July 2010

Land Trust Alliance Annual Rally, Portland , OR, November 2009

Professional Grounds Management Society, Louisville, KY, October 2009

Mid-Atlantic Exotic Pest & Plant Council, Johnstown, PA. July 2009

Society of American Foresters, Western New York Chapter, April 2008

11th Caribbean Urban Forestry Conference, St. Croix, Virgin Islands, June 2006

St. Croix Environmental Association Tree Conservation Workshop, St. Croix, Virgin Islands, June 2006

Southeast Exotic Pest & Plant Council Annual Meeting, Raleigh, NC, May 2006

Association for Zoological Horticulture, *Tree Preservation Specifications Manual* (Industry Standard), 2005

Penn State Invasive Pest, Plants & Weeds Workshop, Luzerne County, PA, October 2005.

KIM KNOWLTON

kknowlton@nrdc.org

865 West End Avenue #6B
New York, NY 10025
(212) 628-8642 / cell (917) 648-5311
fax (212) 988-7742
http://switchboard.nrdc.org/blogs/kknowlton/

CURRENT POSITIONS

2007-present Natural Resources Defense Council, New York, NY
Senior Scientist, Global Warming and Health Project
Conduct research and offer educational outreach to the public and policymakers on the impacts of climate change on health. Leads NRDC's Global Warming and Health Project. Among the scientists participating in the Intergovernmental Panel on Climate Change 2007 Fourth Assessment Report; published research has looked at heat- and smog-related health problems, climate change's effects on pollen, allergies and asthma, flooding and infectious diseases, especially among vulnerable communities.
(see www.nrdc.org/climatemaps)

2005- present Mailman School of Public Health, Environmental Health Sciences Department
Columbia University's Climate and Health Program
Assistant Clinical Professor
Teaching and research on the health impacts of climate change, and devising strategies to increase societal preparedness to cope with global warming.

2011-present: Co-Convening Lead Author for the Human Health chapter of the 2013 Synthesis of the National Climate Assessment (NCA)

2011-present: Field Editor, Epidemiology, International Journal of Biometeorology

2009-present: Chair, Committee on Global Climate Change & Health, American Public Health Association's Environment Section

EMPLOYMENT HISTORY

2001-2005 Mailman School of Public Health, Columbia University
Post-Doctoral/Doctoral Research Associate
Analyzed health impacts of climate change for the New York Climate and Health Project, multi-disciplinary program linking climate, air quality, and land use change modeling projections.

1998-2001 Queens College/CUNY, Center for the Biology of Natural Systems (CBNS)
Medical Screening Coordinator
Designed/coordinated clinical studies, administration, reporting, and recruitment for the Worker Health Protection Program, medical screening offered to thousands of nuclear weapons workers.

1996-1998 Beth Israel Medical Center, New York, NY
Project Manager
Coordinated CDC study of occupational injuries and illnesses among health care workers.

1996-1997	Office of the New York City Public Advocate, New York, NY **Researcher and co-author** (with S Mattei), *Unhealthy Closure: The Need for a Full Environmental Impact Statement on the Department of Sanitation's Long-Term Plan to Control Pollution from Fresh Kills.*
Sept.1994- Sept. 1996	Radioactive Waste Management Associates, Inc., New York, NY **Research Associate** Provided expertise as geologist and health scientist on reviews of environmental impact statements for radioactive waste disposal and decommissioning projects across the US & Canada.
June 1992- Sept.1994	Natural Resources Defense Council, New York, NY **Environmental Consultant** Researched and wrote a critique of EPA's methods for assessing risks from chemical exposures.
June 1992- Aug. 1992	Los Alamos National Laboratory, Los Alamos, NM **Research Assistant** Provided support on environmental and regulatory reviews of hazardous/radioactive waste issues.
Mar. 1978- May 1979	Colorado State Geological Survey, Denver, CO **Field Geologist** Collected and analyzed samples & conducted field surveys of uranium deposits at former mine sites.

TEACHING EXPERIENCE

2008- present	**Mentor** to Columbia University Earth Institute students on Research Projects on climate change impacts and adaptation in the New York City region, as part of an innovative Climate Change Adaptation Initiative.
2005- present	**Lecturer** on Global Warming and Health, Environmental Health Sciences Core Course, Mailman SPH, Columbia University, New York, NY; as well as at Yale University, New York University, The New School for Social Research, Rutgers University, and the University of California at San Francisco Medical School.
Fall 2006	**Mellon Teaching Fellow**, Barnard College, New York NY: Co-Instructor, "Ecotoxicology;" **Doctoral Seminar Instructor**, The Earth Institute, Columbia University, New York, NY: Public Health Seminar Leader, "Environmental Science for Sustainable Development;" **Mentor** to Barnard undergraduates on their Senior Thesis research projects
Spring 2006- 2007	**Instructor**, Mailman SPH, Columbia University, "Public Health Impacts of Climate Change;" Designed and co-taught with Dr. Patrick L. Kinney a new course offering in the Department of Environmental Health Sciences, which received a Dean's Commendation for Excellence in Teaching; and became the foundation of what has developed into Mailman's new ground-breaking Master's Program in Climate Change & Public Health, lead by Dr. Kinney.
2004- present	**Mentor** to undergraduate research interns who assist on NOAA-funded research.

Fall 2003 **Teaching Assistant**, Mailman SPH, Columbia University, "Topics in Environmental Health Science;" Co-designed and conducted masters seminars in conjunction with Prof. Kinney on climate change and health (*piloted ideas that are now being applied in Spring 2006 course*)

Fall 2002 **Teaching Assistant**, Mailman SPH, Columbia University, "Air Pollution;" helped introduce masters students to concepts of atmospheric structure, air pollution sources, regulation, and health effects

ACADEMIC RESEARCH AND TRAINING

2006-2007 "Profiling Carbon Dioxide, Pollen Concentrations and Asthma in the New York City Region," as a 2006-2007 APERG Scholar in the Mid-Atlantic States Section of the Air and Waste Management Association (MASS-A&WMA) Air Pollution Educational Research Grant Program (APERG); *Objectives:* to investigate relationships between the timing and length of spring tree pollen seasons and hospital admissions for respiratory illnesses, and to survey spatial and temporal variations in carbon dioxide across the NY metropolitan region

2006-2007 Research investigating differences in greenhouse gas emissions from four different household types, defined by income and urban versus non-urban location

2004-2007 "Climate Variability, Air Quality and Human Health: Measuring Regional Vulnerability for Improved Decision-Making," funded by National Oceanic and Atmospheric Administration (NOAA); *Objectives*: Assess the degree to which weather and air pollution act independently and/or jointly in contributing to health effects, and to develop and analyze highly resolved exposure and health maps over the state of New York for 1988-2002

2001-2005 "The New York Climate and Health Project: Modeling Heat and Air Quality Impacts of Changing Land Uses and Climate," funded by US Environmental Protection Agency (EPA); *Objectives*: Develop an integrated modeling framework to assess regional climate and air quality under alternative scenarios of global climate change and regional land use change, and corresponding human health risks.

March 26-April 2 2006 DISsertations Initiative for advancement of Climate-Change ReSearch (DISCCRS) Pacific Asilomar, CA
Funded by the National Science Foundation (NSF) to meet challenges in building Successful interdisciplinary careers among recent PhD graduates in climate change impacts. One of 36 fellows selected from doctoral programs throughout the world.

July 2004 NCAR Summer Colloquium on Climate and Health, Boulder, CO (July 2004). Participated in the first summer colloquium on climate and health, held by the Advanced Study Program and Environmental and Societal Impacts Group, National Center for Atmospheric Research.

EDUCATION

October 2005 **Doctor of Public Health, Environmental Health Science**
Mailman School of Public Health, Columbia University, New York, NY

Dissertation: "Mortality in Metropolitan New York Under a Changing Climate"

Projections of future climate changes have often been made at the continental scale, yet more finely resolved projections are needed at regional scales in order for local health impacts and adaptive planning options to be evaluated. To meet these needs, a regional health risk assessment was applied to a dynamically downscaled global-to-regional model system for the tri-state New York metropolitan region. The objective was to project climate-related changes in summer heat stress and ground-level ozone concentrations and their impacts on acute mortality from all internal causes, including respiratory and cardiovascular illnesses.

The health risk assessment used model simulations of future temperature conditions and ozone concentrations developed by the New York Climate and Health Project (NYCHP). In the NYCHP model system, the NASA-Goddard Institute for Space Studies (GISS) general circulation model at 4x5° resolution was linked to the Penn State/NCAR Mesoscale Model 5 (MM5) at 36 kilometer (km) resolution to simulate future daily temperatures. The Community Multiscale Air Quality (CMAQ) atmospheric chemistry model at 36 km horizontal grid resolution was linked to the GISS/MM5 model system to simulate future daily ozone concentrations, in five summers of selected future decades across the 31-county New York metro study area. Concentration-response functions from the epidemiological literature were applied to project relative risk of heat- and ozone-related mortality in New York City in each decade. To isolate the effects of climate change on mortality, population was held constant at Census 2000 levels.

Results under the Intergovernmental Panel on Climate Change (IPCC) A2 (relatively fast-growth) scenario assumptions show that summer heat-related mortality could increase 36% by the 2020s, nearly double (95% increase) by the 2050s, and more than triple (250% increase) by the 2080s as compared to the 1990s. There is a median 4.5% increase in ozone-related acute mortality projected across the 31 counties by the 2050s. Synthesizing the heat and ozone results, for a typical summer in the 2050s, projections of additional overall mortality attributable to climate changes are 96% heat- and 4% ozone-related. The downscaled regional projections revealed heterogeneities in the temperature and ozone simulations: relatively dense population areas tend to coincide with relatively high temperatures, and relatively lower population density with relatively high ozone.

A time series analysis of daily summer mortality from 1990-1999 investigated the independent and joint effects of heat and ozone, and whether the relative risk of heat- and ozone-related mortality among urban populations exceeded that of non-urban. Poisson regression modeled daily death counts as a function of same-daily mean temperature and 1-hour daily maximum ozone concentrations averaged over the same and previous day, adjusting for day of week effects and periodic cycles. Results suggest that the heat effect (RR 1.037 per 10°F; 95% C.I. 1.028, 1.047) is less robust than ozone (RR 1.058 per 100 ppb; 95% CI 1.032, 1.085). There is a significant difference in heat-related mortality risk in urban (RR 1.062; 95% CI 1.048, 1.075) vs. non-urban (RR 1.017; 95% CI 1.006, 1.029) counties, but this is not the case for ozone. This type of health risk assessment modeling could be a useful tool for application in other metropolitan areas to evaluate the relative effects of direct (heat) and indirect (ozone) climate-health impacts that are possible under a changing climate.

June 1993 — **Master of Science, Environmental & Occupational Health Science**
Hunter College, City University of New York, New York, NY

January 1978 — **Bachelor of Arts, Geological Sciences**
Cornell University, Ithaca, NY

AWARDS

2006-2007 — Air Pollution Educational and Research Grant (APERG) Scholarship Program Award recipient, to support research on the relationships between the timing and length of spring tree pollen seasons and hospital admissions for respiratory illnesses, and to survey spatial and temporal variations in carbon dioxide across the NY metropolitan region

2006 Awarded Doctoral Degree with Distinction; I.B.Weinstein Award for Academic Excellence

1993 George H. Kupchik Award, Outstanding Environmental Health Graduate; NIOSH Scholarship Recipient

1973 High School Class Valedictorian; Bausch and Lomb Science Award; NY State Regents Scholarship Recipient

JOURNAL PUBLICATIONS

As lead author:

Knowlton K, Rotkin-Ellman M, Geballe L, Max W, Solomon GM. 2011. Six Climate Change–Related Events In The United States Accounted For About $14 Billion In Lost Lives And Health Costs. Health Affairs 30(11):2167-2176 (Nov. 2011).

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. 2009. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. *Environmental Health Perspectives* 117:61-67 (January 2009).

Knowlton K, Rotkin-Ellman M, King G, et al. 2009. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. *Epidemiology* 19(6):S323(Nov. 2008).

Knowlton K, Lynn BH, Goldberg R, Rosenzweig C, Hogrefe C, Rosenthal J, Kinney PL. 2007. Projecting heat-related mortality impacts under a changing climate in the New York City region. *American Journal of Public Health* 97:2028-2034.

Knowlton K, Rosenthal JE, Hogrefe C, Lynn B, Gaffin S, Goldberg R, Rosenzweig C, Civerolo K, Ku J-Y, Kinney PL. 2004a. Assessing ozone-related health impacts under a changing climate. *Environmental Health Perspectives* 112: 1557-1563.

Knowlton K, Rosenzweig C, Goldberg R, Lynn B, Gaffin S, Hogrefe C, Civerolo K, Ku J-Y, Solecki W, Small C, Oliveri C, Cox J, Rosenthal J, Kinney PL. 2004b. Evaluating global climate change impacts on local health across a diverse urban region. *Epidemiology* 15 (4): S100-S100 (July 2004).

Knowlton K. 2001. Urban history, urban health. *American Journal of Public Health* 91(12):1944-1946.

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As co-author:

Bell, M.L., Goldberg R., Hogrefe, C., Kinney, P.L., Knowlton K., Lynn B., Rosenthal J., Rosenzweig C., and Patz J. 2007. Climate change, ambient ozone, and health in 50 U.S. cities. *Climatic Change* 82:61-76.

Chavarria G, Knowlton K, Atchley D. 2010. The human-climate-wildlife nexus. *Bulletin of the Atomic Scientists* (January/February 2010):48-56 (DOI: 10.2968/066001007).

Civerolo KL, Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Rosenthal J, Knowlton K, and Kinney PL. 2008. Simulated effects of climate change on summertime nitrogen deposition in the eastern US. *Atmospheric Environment* 42(9):2074-2082.

Civerolo KL, Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Rosenthal J, Knowlton K, and Kinney PL. 2007. Estimating the effects of increased urbanization on surface meteorology and ozone concentrations in the New York City metropolitan region. *Atmospheric Environment* 41(9):1803-1818 (Mar 2007).

Hogrefe C. S., B. Lynn, K. Civerolo, J.-Y. Ku, J. Rosenthal, C. Rosenzweig, R. Goldberg, S. Gaffin, K. Knowlton, and P.L. Kinney. 2004. Simulating changes in regional air pollution over the eastern United States due to changes in global and regional climate and emissions. *J Geophysical Res - Atmospheres* 109:D22301 (Nov 17 2004).

Hogrefe C, Rosenzweig C, Kinney P, Rosenthal J, Knowlton K, Lynn B, Patz J, Bell ML. 2004. Health impacts from climate-change induced changes in ozone levels in 85 United States cities. *Epidemiology* 15(4): S94-S95 (July 2004).

Kinney PL, K Knowlton, C Hogrefe, et al. 2007. Melding measurements and models to enrich the study of climate, air quality, and health. *Epidemiology* 18(5):S131(Sept 2007).

Kinney PL, Bell M, Hogrefe C, K Knowlton, et al. 2007. Climate change, air quality, and health: Assessing potential impacts over the eastern US. Epidemiology 18(5):S133(Sept 2007).

Patz JA, Kinney PL, Bell M, Ellis H, Goldberg R, Hogrefe C, Khoury S, Knowlton K, Rosenthal J, Rosenzweig C, Ziska L. 2004. *Heat Advisory: How Global Warming Causes More Bad Air Days*. NY: Natural Resources Defense Council.

Rosenthal JK, Sclar ED, Kinney PL, Knowlton K, Craudereef R, Brandt-Rauf PW. 2007. The links between the built environment, climate and population health: interdisciplinary environmental change research in New York City. *Ann Acad Med Singapore* 97(11):2028-2034.

Sheffield PE, Knowlton K, Kinney PL. 2011. Modeling of regional climate change effects on ground-level ozone and childhood asthma. *American Journal of Preventive Medicine* 41(3):251-257.

Ziska LH, Knowlton K, Rogers CA, Dalan D, Tierney N, Elder MA, et al. 2011. Recent warming by latitude associated with increased length of ragweed pollen season in central North America. *PNAS* 108(10):4248-4251 (March 8, 2011).

BOOK CHAPTERS

As lead author:

Knowlton K. February 10 2011. Globalization and Environmental Health. In: Nriagu JO (ed.) *Encyclopedia of Environmental Health*, vol.2, pp.995-1001. Burlington: Elseveier.

Knowlton K. April 2010 webinar presentation on "Climate Change, Vulnerable Populations and Adaptation" - Chapter 5 on Public Health Adaptation Strategy in CDC/APHA printed guidebook, *Climate Change: Mastering the Public Health Role* (in print April 2011).

Knowlton K, Hogrefe C, Lynn B, Rosenzweig C, Rosenthal J, Kinney PL. 2008. Impacts of heat and ozone on mortality risk in the New York City Metropolitan Region under a changing climate. *In:* Climate Information for the Health Sector. Advances in Global Change Research (Thomson M, Garcia Herrera R, eds.).

Hogrefe C, Ku J-Y, Civerolo K, Lynn B, Werth D, Avissar R, Rosenzweig C, Goldberg R, Small C, Solecki WD, Gaffin S, Holloway T, Rosenthal J, Knowlton K, and Kinney PL. 2004. Modeling the impact of global climate and regional land use change on regional climate and air quality over the northeastern United States. *In:* Air Pollution Modeling and Its Application XVI (Borrego C, Incecik S, eds.). New York: Kluwer Academic/Plenum, pp.135-144.

As co-author:

Kinney PL, Rosenthal JE, Rosenzweig C, Hogrefe C, Solecki W, Knowlton K, Small C, Lynn B, Civerolo K, Ku J-Y, Goldberg R, Oliveri C. 2006. "Assessing Potential Public Health Impacts of Changing Climate and Land Use: The New York Climate and Health Project." *In:* Regional Climate Change and Variability: Impacts and Responses (Ruth M, Donaghy K, Kirshen P, eds.). Cheltenham, UK and Northampton, MA: Edward Elgar, pp.161-189.

Rotkin-Ellman M, Knowlton K, Apatira L, Solomon G. 2011. "Lessons from the Past and Needs for the Future: Place-Based Case Studies of Vulnerability to Climate Change" (book chapter; in press).

Lead author of NRDC Briefing Papers & Fact Sheets on a variety of climate-health topics, including climate change's effects on ground-level ozone smog; pollen, allergies and asthma; heat waves; infectious diseases; harmful algal blooms; and strategies to help prepare to meet these health challenges; available online at: www.nrdc.org/health/globalwarming (2007-present).

PRESENTATIONS

Organizer & Moderator of Sessions on Climate Change and Health, Adaptation in Vulnerable Communities, and Indicators of Vulnerability and Resilience; for the 2011 and 2010 American Public Health Association Annual Meetings.

Organizer & Moderator of Symposia on Climate Change and Health at the 2009 and 2008 American Association for the Advancement of Sciences (AAAS) Annual Meetings.

As presenter:

Session on Climate Change, Air Pollution, and Adaptation in Vulnerable Communities; for the 2010 American Public Health Association Annual Meeting, Denver, Colorado, USA (November 2010).

Capitol Hill Oceans Week, Invited Speaker at Panel on the "Health Impacts of Today's Energy Choices," June 9, 2010, Washington, D.C.

Workshop on Modeling and Mitigation of the Impacts of Extreme Weather Events to Human Health Risks, Rutgers University, June 3, 2010 (Invited Speaker on Heat Wave morbidity, response, adaptation)

International Research Institute for Climate and Society, May 2010 and 2009, Columbia University, New York, NY, Invited Lecturer at Summer Symposium on Climate and Health.

National Environmental Public Health Conference, "Vulnerable Communities & Climate Change: Air Pollution in Metro NY" Centers for Disease Control & Prevention, Atlanta GA, October 26, 2009

National Center for Atmospheric Research Summer Symposium on Climate and Health, Invited Lecturer, July 2009.

American Museum of Natural History, New York, NY, April 2, 2009, "Exploring the Dynamic Relationship Between Health and the Environment" (poster presentation on dengue fever and climate change)

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. 2008. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. Oral presentation at ISEE/ISEA Joint Meeting, Pasadena, CA, October 15, 2008.

Knowlton K, Kinney PL, Bell ML, Hogrefe C, Rosenzweig C. 2005. Assessing potential health impacts of ozone and $PM_{2.5}$ under a changing climate. Poster P-AQ1.8, US Climate Change Science Program (CCSP) Workshop: Climate Science in Support of Decision Making, November 14-16, 2005, Arlington VA.

Knowlton K, Rosenthal J, Rosenzweig C, Goldberg R, Lynn BH, Gaffin S, Solecki WD, Oliveri C, Cox J, Small C, Hogrefe C, Clverolo K, Ku J-Y, Kinney PL. 2004. Projecting the local impacts of global climate change on public health in New York City. American Public Health Association Annual Meeting, November 6-10, Washington, DC.

Knowlton K, Rosenzweig C, Goldberg R, et al. 2004. Evaluating global climate change impacts on local health across a diverse urban region (poster). ISEE/ISEA Mtg, 1-4 August, New York.

Knowlton K and Rosenthal J. 2004. The New York Climate & Health Project: Global and local environmental change and public health. The New York Academy of Sciences, Environment Section (10 May 2004).

Knowlton K (invited speaker). 6 Mar 2004. "Projecting Local Impacts of Global Climate Change." Long Island Univ Annual Biology Conference: The Scientific, Biological, Social, and Economic Impacts of Fossil Fuels. Brooklyn, NY.

Knowlton K, Rosenthal J, Lynn B, Gaffin S, Kinney P, Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Rosenzweig C, Goldberg R. 2003. Assessing Public Health Impacts of Heat and Air Quality Under a Changing Climate in the NYC Metropolitan Area. Amer Geophysical Union Fall Mtg, 8-12 December, San Francisco. Eos Trans. AGU, 84(46), Fall Meet. Suppl., Abstract U32A-0028.

Knowlton K, Rosenthal JE, Gaffin S, Rosenzweig C, Goldberg R, Lynn B, Kinney PL. Modeling Public Health Impacts of Climate Change in the New York Metropolitan Region. Fifth International Conference on Urban Climate (ICUC-5), 1-5 September 2003, Lodz, Poland.

As co-author:

Civerolo K, Biswas J, Hogrefe C, Rosenthal J, Knowlton K, Lynn B, Ku J-Y, Goldberg R, Rosenzweig C, Kinney PL. 2004. Modeling Future Climate and Air Quality in the New York City Metropolitan Area, Presented at the Symposium on Planning, Nowcasting, and Forecasting in the Urban Zone, 84th AMS Annual Meeting, Jan. 11-15, Seattle, WA.

Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Civerolo K, Ku J-Y, Rosenthal R, Knowlton K, Kinney PL. 2005. Utilizing CMAQ Process Analysis to Understand the Impacts of Climate Change on Ozone and Particulate Matter. Models-3 Users' Workshop, September 26-28, Chapel Hill, NC. Online: http://www.cmascenter.org/html/2005_conference/abstracts/3_2.pdf.

Hogrefe C, Knowlton K, Goldberg R, Rosenthal J, Rosenzweig C, Lynn BH, Kinney PL. 2005. Integrating observations and MM5/CMAQ predictions to study the link between climate variability, air quality and health in New York State: Project description and initial results. Presented at the NOAA/EPA Golden Jubilee Symposium on Air Quality Modeling and Its Applications, September 20-21, Research Triangle Park, NC.

Hogrefe C, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Solecki WD, Small C, Gaffin S, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2004. Air quality in future decades – determining the relative impacts of changes in climate, anthropogenic and biogenic emissions, global atmospheric composition, and regional land use. Preprints of the 27th NATO/CCMS International Technical Meeting on Air Pollution Modeling and Its Applications, October 25 - 29, Banff, Canada, pp. 158-165.

Hogrefe C, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Solecki WD, Small C, Gaffin S, Goldberg R, Rosenzweig C, Kinney PL. 2004. Modeling the Air Quality Impacts of Climate and Land Use Change in the New York City Metropolitan Area. Models-3 Users' Workshop, October 18-20, Research Triangle Park, NC. Online:

http://www.cmascenter.org/html/2004_workshop/abstracts/Climate%20Multiscale/Hogrefe_abstract.pdf.

Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2003. Climate change and ozone air quality over the eastern United States: A modeling study. Fall Meeting 2003, San Francisco, CA, December 8-12. Eos Trans. AGU, 84(46), Fall Meet. Suppl., Abstract U32A-0027.

Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2003. Climate change and ozone air quality: applications of a coupled GCM/MM5/CMAQ modeling system. Proceedings of the 2nd Models-3 Users' Workshop, October 27-29, Research Triangle Park, NC. Online at: http://www.cmascenter.org/2003_workshop/presentations/session2/hogrefe_abstract.pdf.

Kinney PL, Hogrefe C, Lynn BH, Rosenzweig C, Rosenthal J, Knowlton K. 2005. Independent and joint impacts of heat and ozone mortality risk under a changing climate. Wengen Tenth Annual Workshop on Global Change Research, September 12-14, Wengen, Switzerland.

Kinney P, Knowlton K, Rosenthal J, Rosenzweig C, Solecki WD, Hogrefe C, Lynn B, Avissar R. 2003. Heat Stress Modeling in the NYC Metropolitan Area: Estimates for the 2050s Using a Linked Global-Regional Climate Modeling System. 2003 Open Mtg: Human Dimensions of Global Environmental Change, Montreal, Canada, October 16-18.

Rosenthal JR, Kinney PL, Knowlton K. 2004. Reshaping the built environment to reduce public health impacts of the urban heat island effect. American Public Health Association Annual Meeting, November 6-10, Washington, DC.

OTHER OUTREACH, ADVOCACY, MEDIA COVERAGE

Developed NRDC webpages on *Climate-Health Vulnerability* (www.nrdc.org/climatemaps) and *2011 Extreme Weather* (www.nrdc.org/extremeweather)

December 2011 invited presentation on Climate Change, Aeroallergens and Health to the Northern Central Weed Science Society, Milwaukee, WI

2011: Webinars on Climate Change and Health for National Nurses groups for continuing medical education credits; for Faith Community Leadership groups

Nov 2011 presentation at NJ Climate Change Adaptation Workshop at Rutgers University

Oct.29-Nov.3, 2011: presentations at the American Public Health Association Annual Mtg, Washington, DC on communicating climate-health vulnerability; and organizer of two panels, including a Special Session on "Climate Change & Health: The Global Challenge"

Sept 24-25, 2011: invited presentation at workshop on health, economics, and climate change, Boston, MA

May 26-27, 2011: International Research Institute for Climate Change, Columbia University, NY, NY – Climate Change & Health presentations and trainings for international experts and researchers

March 28-20, 2011: Indo-US Heat Vulnerability Workshop, Ahmedabad, India

Invited speaker, April 2010, Barnard College panel with Dr. Mary Robinson on climate change, NYC.

January 2010 Lecture on the health impacts of global warming as part of the *Cambridge Forum* lecture series - one of public radio's longest running public affairs programs heard on NPR stations across the US - titled, "After Copenhagen," online at: http://forum-network.org/lecture/health-impacts-global-warming.

Speaking about the impacts of changing climate conditions on infectious diseases like dengue fever in a segment titled, "Outbreak" on *Planet Green* television, October 2009.

Testimony to NYC Council on climate change, infrastructure adaptation and health, May 2008.

CARE International Executive Committee Meeting, New York, NY: *Developing Responses to the Climate Crisis* (7 June 2007).

Testimony to New York City Council (Environment Committee) on climate research findings in support of proposed Local Law No.661 to limit greenhouse gas emissions in NYC (June 2006, June 2005).

The New York Times. Worked with journalists to clarify research issues: "Forecast for New York this century: Hotter and wetter" (*New York Times*, Metro Section, 27 June 2004); "Climate scientists zoom in on changes" (*New York Times*, Metro Section, 9 December 2003).

National Public Radio. "Degrees of Concern: Climate Change and New York City," K Knowlton on West Nile virus and climate variability, broadcast interview on *Living on Earth*, nationally syndicated NPR show, 11 October 2003.

The American Museum of Natural History, Dartmouth College, The 92nd Street Y (NYC), *Science News*, *Greenwire*, *New York Daily News*, *The Poughkeepsie Journal* and *Downtown Express*.

OTHER PROFESSIONAL ORGANIZATIONAL AFFILIATIONS

American Association for the Advancement of Science; American Academy of Allergy, Asthma and Immunology; American Geophysical Union; American Meteorological Society; New York Academy of Sciences; International Society for Environmental Epidemiology.

1/11/2012

GINA M. SOLOMON M.D., M.P.H.

111 Sutter Street, 20th Floor, San Francisco, CA 94104 ♦ (415) 875-6100 ♦ gsolomon@nrdc.org

EMPLOYMENT

Senior Scientist, ***Natural Resources Defense Council, 1996 - present***
Conduct research and investigation into priority environmental hazards with a focus on threats to children's health. Advocate for policy changes to improve laws and regulations to protect health. Represent NRDC in the press, legislative and agency hearings, and public fora. Supervise 7 full-time staff and numerous interns and students. Raise and manage an annual budget of over $800,000.

Director, UCSF Occupational and Environmental Medicine Residency Program, ***2008-present***
Manage all aspects of the physician training program in occupational and environmental medicine at UCSF, including directing the interview and selection process, shaping the educational requirements, managing the budget, and maintaining funding and accreditation. Supervise an associate director, program coordinator, and 4-7 residents and fellows.

Health Sciences Clinical Professor, ***University of California San Francisco, 2011 – present***
Precept occupational and environmental medicine (OEM) residents and fellows in clinic. Teach at journal club, case conference, grand rounds, and summer didactics. Teach Epi 170.16 Environment and Health course for medical and nursing students. Supervise residents from four medical centers for month-long rotations at NRDC.

Associate Director, Pediatric Environmental Health Specialty Unit, ***University of California San Francisco, 2003 - Present***

Associate Clinical Professor of Medicine, ***University of California San Francisco, 2006 –2011***

Assistant Clinical Professor of Medicine, ***University of California San Francisco, 1998 - 2006***

Clinical Instructor in Medicine, ***University of California San Francisco, 1996 - 1998***

Consultant, Ergonomics Evaluation Project, ***Massachusetts Division of Industrial Accidents, 1996 - 1997***

Fellow, Occupational and Environmental Medicine, ***Harvard School of Public Health, 1996***

Clinical Instructor in Medicine, ***Harvard University School of Medicine, 1991 - 1995***

Resident, Primary Care Internal Medicine, ***Mount Auburn Hospital, 1991 - 1995***

Research Assistant in Environmental Medicine, ***Institute of Medicine, Washington DC, 1994***

PROFESSIONAL ACTIVITIES

Science Advisory Board, *U.S. Environmental Protection Agency, 2011-2014*

Editorial Board, *Environmental Health Perspectives, 2010 – present*

Scientific Guidance Panel, *California Environmental Contaminant Biomonitoring Program, 2007-present*

Tracking Implementation Advisory Group, *California Department of Public Health, 2006 - present*

Board of Directors, *San Francisco Bay Area Physicians for Social Responsibility, 2000 – present*

Committee on Human and Environmental Exposure Science in the 21st Century, *National Research Council, 2010 – 2012*

Board of Scientific Counselors, *National Toxicology Program, 2008 – 2011*

California Adaptation Advisory Panel, *Governor of California*, 2010

Science Advisory Board Drinking Water Committee, *U.S. Environmental Protection Agency, 2004-2010*

Science Advisory Board Acrylamide Panel, *U.S. Environmental Protection Agency, 2007 – 2008*

Reviewer, *American Academy for the Advancement of Sciences* LSDF 09-01: Innovative research programs to improve health and health care, 2009

Committee on Toxicity Testing and Assessment of Environmental Agents, *National Research Council, 2004 -2007*

Childhood Lead Poisoning Prevention Expert Advisory Committee, *California Department of Health Services, 2004 - 2006*

Scientific Advisory Group, Environmental Epidemiology and Biomonitoring, *CA Dept of Health Services Environmental Health Investigations Branch, 2000-2004*

SB702 Expert Working Group on Public Health Tracking, *California Department of Health Services, 2002 - 2004*

Science Advisory Board Trichloroethylene Panel, *U.S. Environmental Protection Agency, 2002*

Strategic Advisory Committee, *National Center for Environmental Health, CDC, 2001 - 2002*

Endocrine Disruptor Screening and Testing Advisory Committee, *U.S. Environmental Protection Agency, 1996 - 1998*

Board of Directors, *Consortium for Environmental Education in Medicine, 1998 - 2000*

Pesticides and Environmental Education for Health Providers Committee, *National Environmental Education & Training Foundation, 1998 - 2000*

Peer Reviewer: *Journal of the American Medical Association (JAMA); American Journal of Public Health; Climatic Change; Environmental Health Perspectives; Canadian Medical Association Journal; Environmental Science and Technology; Journal of Occupational and Environmental Medicine; Environmental Research; Environmental Geochemistry and Health; Indoor Air; International Journal of Occupational and Environmental Health; Tobacco Control; European Journal of Clinical Nutrition; American Journal of Preventive Medicine; Environmental Pollution; Chemosphere; Journal of Epidemiology and Community Health.*

EDUCATION

Masters in Public Health, *Harvard School of Public Health, 1994*
Doctorate of Medicine, *Yale School of Medicine, 1991*
Bachelor of Arts, Comparative Literature, Magna cum Laude, *Brown University, 1986*

CERTIFICATION AND LICENSING

National Board of Medical Examiners, 7/92
American Board of Internal Medicine, 8/95, Recertified 5/05
American Board of Preventive Medicine, 2/98, Recertified 12/08
California Medical License number: G 083110

AWARDS AND RECOGNITION

CAAT Recognition Award, *Johns Hopkins University Center for Alternatives to Animal Testing, 2009*
Certificate of Appreciation, *Center for Community Action and Environmental Justice, 2007*
Certificate of Appreciation, *California Safe Schools, 2004*
Clean Air Award for Research, *American Lung Association of the Bay Area, 2004*
Ten Women's Health Pioneers, *The Green Guide, 2004*
Environmental Heroes Award, *The Breast Cancer Fund, 2002*
Will Solimene Award for Excellence in Medical Writing, *American Medical Writers Association, 2000*
Occupational Physicians Scholarship Fund Award, *1993, 1995*
Farr Scholarship Award, *Yale Medical School, 1988, 1989*
Phi Beta Kappa, *Rhode Island Chapter, 1986*

SCIENTIFIC PUBLICATIONS

Knowlton K, Rotkin-Ellman M, Geballe L, Max W, Solomon G. Six Climate Change–Related Events in the United States Accounted For About $14 Billion in Lost Lives and Health Costs. Health Affairs. 30(11): 1-10. 2011.

Rotkin-Ellman M, Wong KK, Solomon GM. Seafood Contamination after the BP Gulf Oil Spill and Risks to Vulnerable Populations: A Critique of the FDA Risk Assessment. Environ Health Perspect, 2011. http://dx.doi.org/10.1289/ehp.1103695.

Solomon G, Huddle A, Silbergeld EK, Herman J. Chapter 8. Manganese in Gasoline: Are We Repeating History? In: Clapp R (Ed.). From Critical Science to Solutions: The Best of Scientific Solutions. Baywood Publishing Inc., 2011. ISBN: 978-0-89503-404-5.

Rotkin-Ellman M, Navarro KM, Solomon GM. Gulf oil spill air quality monitoring: lessons learned to improve emergency response. Environ Sci Technol. 44(22):8365-6, 2010.

Solomon G, Janssen SJ. Health Effects of the Gulf Oil Spill. JAMA, 304(10):1118-9, 2010.

Solomon G, Janssen SJ. Communicating with Patients and the Public About Environmental Exposures and Reproductive Risk. In: Woodruff TJ, Janssen SJ, Guillette LJ, Giudice LC (eds), Environmental Impacts on Reproductive Health and Fertility. Cambridge Press, Cambridge, UK, 2010.

Rotkin-Ellman M, Solomon G, Gonzales CR, Agwaramgbo L, Mielke HW. Arsenic Contamination in New Orleans Soil: Temporal Changes Associated with Flooding. Environmental Research, 110(1):19-25, 2010.

Krewski D, Acosta D Jr, Andersen M, Anderson H, Bailar JC 3rd, Boekelheide K, Brent R, Charnley G, Cheung VG, Green S Jr, Kelsey KT, Kerkvliet NI, Li AA, McCray L, Meyer O, Patterson RD, Pennie W, Scala RA, Solomon GM, Stephens M, Yager J, Zeise L. Toxicity testing in the 21st century: a vision and a strategy. Toxicol Environ Health B Crit Rev. 13(2-4):51-138, 2010.

Solomon G, Huang A, Godsel R. Contaminants in the Air and Soil in New Orleans After the Flood: Opportunities and Limitations for Community Empowerment, In: Bullard R, Wright B (eds). Race, Place, and Environmental Justice After Hurricane Katrina. Westview Press, Boulder, CO, 2009.

Solomon G. Physicians' Duty to Be Aware of and Report Environmental Toxins. Virtual Mentor, 11(6):434-442, 2009. http://virtualmentor.ama-assn.org/2009/06/ccas2-0906.html.

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. The 2006 California Heat Wave: Impacts on Hospitalizations and Emergency Department Visits Environ Health Perspect, 117: 61-67, 2009. http://www.ehponline.org/members/2008/11594/11594.pdf.

Woodruff T, Zeise L, Axelrad D, Guyton KZ, Janssen S, Miller, M, Miller G, Schwartz J, Alexeef G, Anderson H, Birnbaum L, Bois F, Cogliano J, Crofton K, Euling SY, Foster P, Germolec D, Ginsberg G, Gray E, Hattis D, Kyle A, Leubke R, Luster M, Portier C, Rice D, Solomon G, Steinmaus C,

Vandenberg J, Zoeller T. Meeting Report: Moving Upstream: Evaluating Adverse Upstream Endpoints for Improved Risk Assessment and Decision Making. Environ Health Perspect, 116:1568–1575 (2008). http://www.ehponline.org/members/2008/11516/11516.pdf.

Humphreys EH, Janssen S, Heil A, Hiatt P, Solomon G, Miller MD. Outcomes of the California Ban on Pharmaceutical Lindane: Clinical and Ecologic Impacts. Environ Health Perspect, 116:297-302 (2008). doi:10.1289/ehp.10668.

Humphries E, Solomon G. Helping Your Patients Manage Asthma: Focus on the Source. Medscape, http://www.medscape.com/viewarticle/572573.

Solomon GM, Janssen S. Talking with patients and the public about endocrine disrupting chemicals. In: Endocrine-disrupting Chemicals: From Basic Research to Clinical Practice. Ed. Andrea C. Gore. Part of "Contemporary Endocrinology," series editor P. Michael Conn, Humana Press, Totowa, NJ, 2007.

Karr C, Solomon GM, Brock-Utne A. Health effects of common home, lawn and garden pesticides. Ped Clin N Am 54(1):63-80, 2007.

Thundiyil J, Solomon GM, Miller MD. Transgenerational exposures: Persistent chemical pollutants in the environment and breast milk. Ped Clin N Am 54(1):81-101, 2007.

Solomon GM, Hjelmroos-Koski M, Rotkin-Ellman M, Hammond K. Air quality in New Orleans, Louisiana after flooding: Mold, endotoxin, and particulate matter, October - November 2005. Environ Health Perspect 114(9):1381-1386, 2006.

Solomon GM, LaDou J, Wesseling C. Environmental Exposures and Controls, in LaDou (Ed.) Occupational and Environmental Medicine. Fourth Ed. Appleton and Lange, Stamford CT, 2006.

McDaniel P., Solomon G, Malone RE. The ethics of industry experimentation using employees: The case of taste-testing pesticide-treated tobacco. Am J Public Health 96(1):37-46, 2006.

McDaniel PA, Solomon G, Malone RE. The Tobacco Industry and Pesticide Regulations: Case Studies from Tobacco Industry Archives. Environ Health Perspect 113(12):1659-1665, 2005.

Bailey D, Solomon G. Pollution Prevention at Ports: Clearing the Air. Environ Impact Assess Review 24:749-774, 2004.

Solomon G, Humphreys E, Miller M. Asthma and the Environment: Connecting the Dots: what role do environmental exposures play in the rising prevalence and severity of asthma? Contemp Pediatrics 21(8), 2004.

Solomon GM, Hawes A, Quintero A, Widess E. Approaches to Occupational and Environmental Law in: Rosenstock L and Cullen M. (Eds.) Textbook of Clinical Occupational and Environmental Medicine, Second Edition. WB Saunders/Mosby/Churchill Livingstone, Philadelphia, 2004.

Solomon GM, LaDou J, Jackson RJ. Environmental Exposures and Controls, in LaDou (Ed.) Occupational and Environmental Medicine. Third Ed. Appleton and Lange, Stamford CT, 2003.

Solomon GM, Balmes J. Health Effects of Diesel Exhaust. Clinics in Occup & Environ Med 3:61-80, 2003.

Miller M, Solomon G. Environmental Risk Communication for the Pediatrician. Pediatrics 112:211-221, 2003.

Miller M, Solomon G. Pesticides, in: Etzel RA and Balk SJ (Eds). Handbook of Pediatric Environmental Health, Second Ed. American Academy of Pediatrics, Elk Grove Village, IL, 2003.

Solomon GM. Rare and Common Diseases in Environmental Health. San Francisco Medicine 75(9):14-16, 2002.

Solomon GM, Huddle AM. Low levels of persistent organic pollutants raise concerns for future generations. J of Epi and Commun Health. 56(11):826-827, 2002.

Solomon GM and Schettler T. Endocrine Disruption. In McCally M. (Ed.) Life Support: The Environment and Human Health. MIT Press, Cambridge MA, 2002.

Solomon GM, Weiss P. Chemical Contaminants in Breast Milk: Time Trends and Regional Variability. Environ Health Perspect 110(6): A339-A347, 2002.

Pandya RJ, Solomon GM, Kinner A, Balmes JR. Diesel Exhaust and Asthma: Potential Hypotheses and Molecular Mechanisms of Action, Environ Health Perspect 110(suppl 1):103-112, 2002.

Chaisson C, Solomon G. Children's Exposure to Toxic Chemicals – Modeling their World to Quantify the Risks. Neurotoxicology 22:563-565, 2001.

Solomon GM, Schettler T. Emerging Issues in Environmental Health: Endocrine Disruption. Canadian Med Assn Journal 163(11): 1471-1476, 2000.

Solomon GM. Hormones, Chemicals, and Public Policy. Chem and Engineering News, 78(32): 66-67, 2000.

Schettler T, Solomon GM, Valenti M, and Huddle AM. Generations at Risk: Reproductive Health and the Environment. Massachusetts Institute of Technology Press, Boston, June 1999.

Milton DK, Solomon GM, Rossiello RA, Herrick RF. Risk and Incidence of Asthma Attributable to Occupational Exposure among HMO Members. Am J Ind Med 33(1):1-10, 1998.

Solomon GM. Reproductive Toxins: A Growing Concern at Work and in the Community. J Occ Env Med 39:105-107, 1997.

Solomon GM, Huddle AM, Silbergeld EK, Herman D. Manganese in Gasoline: Are We Repeating History? New Solutions 7(2):17-25, 1997.

Frumkin H, Solomon GM. Manganese in the U.S. Gasoline Supply. Am J Ind Med 31:107-115, 1997.

Solomon GM, Morse E, Garbo M, Milton DK. Stillbirth after Occupational Exposure to N-Methyl-2-Pyrrolidone: A case report and review of the literature. J Occ Env Med 38:705-713, 1996.

Esswein E, Trout D, Hales T, Brown R, Solomon GM. Exposures and Health Effects: An Evaluation of Workers at a Sodium Azide Production Facility. Am J Ind Med 30:343-350, 1996.

Parker J, Solomon GM. Decades of Deceit: The History of Bay State Smelting. New Solutions 5:80-89, 1995.

REPORTS

Knowlton K, Solomon G, Rotkin-Ellman M. Fever Pitch: Mosquito-Borne Dengue Fever Threat Spreading in the Americas. Natural Resources Defense Council, New York, NY, 2009. http://www.nrdc.org/health/dengue/files/dengue.pdf.

Rotkin-Ellman M, Solomon G. Poisons on Pets II: Toxic Chemicals in Flea and Tick Collars. Natural Resources Defense Council, New York, NY, 2009. http://www.nrdc.org/health/poisonsonpets/files/poisonsonpets.pdf.

Rotkin-Ellman M, Quirindongo M, Sass J, Solomon G. Deepest Cuts: Repairing Health Monitoring Programs Slashed Under the Bush Administration. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/health/deepestcuts/deepestcuts.pdf.

Wall M, Rotkin-Ellman M, Solomon G. An Uneven Shield: The Record of Enforcement and Violations Under California's Environmental, Health and Workplace Safety Laws. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/legislation/shield/shield.pdf.

Knowlton K, Rotkin-Ellman M, Solomon GM. Sneezing and Wheezing: How global warming could increase ragweed allergies, air pollution, and asthma. Natural Resources Defense Council, New York, NY, 2007. http://www.nrdc.org/globalWarming/sneezing/sneezing.pdf.

Cohen A, Janssen S, Solomon GM. Clearing the Air: Hidden Hazards in Air Fresheners. Natural Resources Defense Council, New York, NY, 2007. http://www.nrdc.org/health/home/airfresheners/airfresheners.pdf

Solomon GM, Nance E, Janssen S, White WB, Olson E. Drinking water quality in New Orleans: June-October 2006. Natural Resources Defense Council, New York, NY, January 2007. http://www.nrdc.org/health/effects/katrinadata/water.pdf.

Solomon GM, Rotkin-Ellman M. Contaminants in New Orleans Sediment: An Analysis of EPA Data. Natural Resources Defense Council, New York, NY, February 2006. http://www.nrdc.org/health/effects/katrinadata/sedimentepa.pdf.

Solomon GM, Campbell TR, Feuer GR, Masters J, Samkian A, Paul KA. No Breathing in the Aisles: Diesel Exhaust Inside School Buses. Natural Resources Defense Council, New York, NY, 2001. http://www.nrdc.org/air/transportation/schoolbus/schoolbus.pdf.

Solomon G, Ogunseitan OA, Kirsch J. Pesticides and Human Health: A Resource for Health Care Professionals. Physicians for Social Responsibility, San Francisco, CA, 2000. http://www.psrla.org/pahk.pdf

Solomon GM, Mott L. Trouble on the Farm: Growing up with Pesticides in Agricultural Communities. Natural Resources Defense Council, New York, NY, 1998. http://www.nrdc.org/health/kids/farm/farminx.asp.

PUBLISHED ABSTRACTS

Knowlton K, Solomon G, Chavarria G. Preparing for the Health Impacts of Climate Change: Science and Societal Strategies. AAAS Annual Meeting Abstract, 2008.

Janssen S, Solomon G, Chavarria G. Measuring Human Exposures to Hormone-Disruptors: Scientific Tools for Global Health. AAAS Annual Meeting Abstract # 090-096, 2008.

Rotkin-Ellman M, Solomon G. Soil Contamination in New Orleans: Arsenic and Lead Before and After Katrina. APHA Annual Meeting Abstract #163091, 2007.

McDaniel P, Malone R, Solomon GM. The Tobacco Industry and Pesticide Regulations. Society for Research on Nicotine and Tobacco, 10th Annual Scientific Sessions, 2004.

Solomon GM. Mercury and other Persistent Fish Pollutants: Risks to the Fetus and Child. APHA Annual Meeting Abstracts, 2003

Solomon GM. Endocrine Disruptors and Current Science Policy Developments. APHA Annual Meeting Abstracts, 4185, 2000.

Solomon GM. Special Risks to Children in Agricultural Settings. Neurotoxicology, 2000.

Solomon GM, Mott L. Disproportionate Exposures and Susceptibility: Pesticide risks to farm children. Neurotoxicology 20:1, 1999.

Solomon GM, Schettler T, Huddle A, Valenti M. Endocrine Disruptors: A lens on low dose health effects. Epidemiology 9(4): S54, 1998.

Solomon GM, Huddle AM, Schettler T, Valenti M. The Tradition of Statistical Significance: An impediment to prudent public health? Epidemiology 9(4): S75, 1998.

Solomon GM. Protecting Human Health From Endocrine Disruptors: Are toxicology and risk assessment up to the challenge? APHA Annual Meeting Abstracts, 2024, 1998.

Solomon GM. The Reproductive and Developmental Effects of Organic Solvents: The dilemma of identifying a culprit. APHA Annual Meeting Abstracts, 10, 1996.

Solomon GM, Milton DK. The Occupational Asthma Incidence Study: A pilot project. APHA Annual Meeting Abstracts, 177, 1996.

Garbo M, Milton D, Morse EP, Solomon G. From DBCP to NMP: Have we progressed? APHA Annual Meeting Abstracts, 408, 1996.

SELECTED PRESENTATIONS

Congressional Testimony and Briefings:

Cancer and the Environment
Safer Chemicals Healthy Families Congressional Briefing, 4/7/11

Cancer Clusters and the Environment
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 3/29/11

Reproductive Health and the Environment
Pew Charitable Trusts Congressional Briefing, 6/11/10

Health Effects of the Gulf Oil Spill
Hearing of the House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, Washington DC, 6/10/10

Protecting Children from Environmental Threats
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 3/17/10

Endocrine Disrupting Chemicals in Drinking Water
Hearing of the House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, Washington DC, 2/25/10

Biomonitoring: A Tool for Public Health Policy
American Chemistry Society Congressional Briefing, 3/09

Health Risks to Children and Communities from Recent EPA Decisions on Air and Water Quality
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 2/07

Selected TV and Radio Appearances:

Gulf Oil Spill Health Effects
PBS Need to Know, National TV, 6/10
CBS Evening News, National TV, 6/10
CNN Evening News, National TV, 5/10
CBS The Early Show, National TV, 5/10

Cancer Cluster in Fort Chipewyan, Alberta
Canadian Broadcasting Company National Radio, 5/10

Protecting Children from Toxins in the Home
Childhood Matters, KISS-FM Radio, San Francisco, CA, 7/05; 9/07

EPA's Chemical Testing Program
NPR's Living on Earth, 6/07

Protecting the Body from Heat
MarketWatch Special Report: An Investors Guide to Global Warming (Web Video), 5/07

Mold Testing in New Orleans Post-Katrina
National Public Radio, Living on Earth, 11/05
CNN News, 11/05

Diesel Exhaust Inside School Buses
National Public Radio, Science Friday, 2/01

Selected Scientific and Educational Presentations:

Children's Health and the Gulf Oil Spill
Pediatric Academic Societies Annual Meeting, 5/11

Toxicity Testing in the 21st Century
National Academy of Sciences Conference, 5/09

Biomonitoring: A Tool for Public Health Policy
UC Berkeley School of Public Health, 3/09
UCSF School of Medicine, 1/09

Preparing for Climate Change in California
UCSF Continuing Medical Education Course, 11/09
UCSF School of Medicine, 1/08, 3/09
Public Policy Institute of California, 12/08
UCLA School of Public Health, 10/07

Health Effects of Global Warming

Governor's Global Climate Summit, 9/09
Grantmakers in Health Annual Conference, 3/09
UCSF Advances in Internal Medicine Course, 5/08
California Joint Legislative Briefing, Sacramento, CA, 8/06

Health Hazards to Day Laborers
UCSF School of Medicine FCM 184, 12/08, 11/09
Clinica Martin Baro, 3/10

Taking an Environmental History
Kaiser San Francisco Internal Medicine Residents, 10/09
SFGH Internal Medicine Residents, 7/09
UCSF School of Medicine, 1/09
N245 UCSF Nursing School, 2/09
UCSF Family and Community Medicine Residents, 12/08
UCSF Integrative Medicine Course, 5/08

Pediatric Environmental Health "Toolkit" for Pediatricians
San Francisco General Hospital Pediatric Grand Rounds, 10/07
Stanford Lucile Packard Children's Hospital Grand Rounds, Palo Alto, Ca, 4/07
Oakland Children's Hospital, Oakland, CA, 5/07
O'Connor Hospital Combined Grand Rounds, San Jose, CA, 4/07
Kaiser Santa Teresa Hospital, San Jose, CA, 6/07
Kaiser Oakland, Oakland, CA, 10/06

Cancer and the Environment
Institute for Functional Medicine Annual Meeting Plenary Address, 5/10
Northern California Cancer Center, 3/08, 10/08
UCLA Ted Mann Family Resource Center Insights Into Cancer Lecture, Los Angeles, CA, 3/07

Mold Contamination in New Orleans Post-Katrina
UC Irvine Medicine Grand Rounds, 12/07
Stanford Law School, 10/07
CDC National Environmental Public Health Conference, Atlanta, GA, 12/06

Healthy Food in Healthcare
Stanford Medical School, Palo Alto, CA, 10/05, 10/06, 11/09
UCSF Medical Center, San Francisco, CA, 3/06 & 5/06
CleanMed National Conference, Seattle, WA, 4/06
John Muir Medical Center Combined Grand Rounds, Walnut Creek, CA, 3/06

Endocrine Disruptors in the Home and Community
Heinz Conference on Women and the Environment, Boston, MA, 10/06

Controlling Environmental Hazards in Communities of Color
National Legal Aid and Defenders Association Conference, Snowbird, UT, 6/06

Breastfeeding in a Contaminated World
March of Dimes Perinatal Conference, Chicago, IL, 3/06

Mercury and Current Fish Consumption Guidelines for Children
American Academy of Pediatrics Annual Conference, San Francisco, CA, 9/05

Why Should an Internist Care About Environmental Disease?
U.C. Davis Internal Medicine Grand Rounds, Sacramento, CA 7/10
Kaiser Permanente Medical Grand Rounds, San Francisco, CA, 4/04
UCSF Alice Hamilton Memorial Lecture Grand Rounds, San Francisco, CA, 3/04

BRIANA E. MORDICK

PROFESSIONAL EXPERIENCE

NATURAL RESOURCES DEFENSE COUNCIL *Washington, DC*
OIL & GAS SCIENCE FELLOW *September 2010 – Present*

Technical advisor on oil and gas related issues. Provides scientific expertise and analysis in support of advocacy efforts. Engages with and serves as a liaison to the scientific community.

ANADARKO PETROLEUM CORPORATION *January 2005 – September 2010*

Greater Natural Buttes Natural Gas Field, Uinta Basin, UT (June 2009 – September 2010)
Senior Geologist & Team Lead

- Geologist responsible for drilling 50+ wells and selecting 500+ new drilling locations
- Worked to develop new criteria and methods for selecting optimal well locations
- Lead a team of four co-workers who were responsible for two drilling rigs and hundreds of wells; organized and lead meetings; provided weekly updates to management; served as point of contact for extended team members

Salt Creek Field CO_2 Enhanced Oil Recovery Project, Natrona County, WY (Nov 2006 – June 2009)
Geologist II

- Described and analyzed core data to develop full field depositional model
- Analyzed well logs, core, and production data to determine flow pathways of oil and CO_2
- Assisted in construction of digital 3D geologic reservoir model used for oil and CO_2 flow simulation modeling

Ozona Natural Gas Field, Crockett County, Texas (Jan 2005 – Nov 2006)
Geologist I

- Geologist responsible for drilling 100+ natural gas wells, analyzing logs, and recommending zones to be completed for production
- Remapped subsurface geology, resulting in greater predictability of productive zones in wells
- Successfully presented underdeveloped natural gas prospect at the North American Prospect Expo (NAPE) and engaged a partner to develop these prospects

ANADARKO PETROLEUM CORPORATION *The Woodlands, Texas*
GEOSCIENCE INTERN *September 2004 - November 2004*

Evaluated the Baxter shale in active Wyoming oil and gas fields for shale-gas production potential.

EDUCATION

UNIVERSITY OF NORTH CAROLINA AT CHAPEL HILL *Chapel Hill, North Carolina*
MASTER OF SCIENCE, GEOLOGICAL SCIENCES *September 2002 – May 2005*

Thesis: Pyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California

BOSTON UNIVERSITY *Boston, Massachusetts*
BACHELOR OF ARTS, EARTH SCIENCE *September 1998 – May 2002*

Senior Thesis: Provenance of discrete ash layers from the Izu-Bonin Arc system using Laser Ablation-Inductively Coupled Plasma-Mass Spectrometry

BRIANA E. MORDICK

PUBLICATIONS

Mordick, B.E., Glazner, A.F., 2006, Clinopyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California: Contributions to Mineralogy and Petrology, v. 152, no. 1, p. 111-124.

SELECTED PRESENTATIONS

- October 19, 2010:
  - Forum: National Research Council of the National Academies, Board on Earth Sciences and Resources, Committee on Earth Resources
    - Meeting Title: "Meeting Our Nation's Natural Resource Needs: Balancing Risks and Rewards"
    - Presentation Title: "Environmental Impacts of Oil and Gas Production"
- March 11, 2011:
  - Forum: EPA Hydraulic Fracturing Study Technical Workshop
    - Meeting Title: Well Construction and Operations
    - Presentation & Abstract Title: "Risks to Drinking Water from Oil and Gas Wellbore Construction and Integrity: Case Studies and Lessons Learned"
- June 1, 2011:
  - Forum: Environmental Entrepreneurs Monthly TeleSalon
    - Meeting Title: "Natural Gas in the Mix: Finding the Balance"
    - Presentation Title: "Environmental Impacts of Natural Gas Production"

- September 27, 2011:
  - Forum: University of Wyoming Hydraulic Fracturing Forum
    - Meeting Title: Hydraulic Fracturing, A Wyoming Energy Forum
    - Presentation Title: Hydraulic Fracturing Best Practices: Mitigating Environmental Concerns

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 8

Joint Comments on the New York State RDSGEIS (January 11, 2012)

January 27, 2012

January 11, 2012

Attn: dSGEIS Comments
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Dear Sir or Madam:

Enclosed please find a Joint Legal Memorandum on the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program and Proposed Regulations for Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Reservoirs prepared by Catskill Mountainkeeper, Delaware Riverkeeper Network, Earthjustice, the Natural Resources Defense Council, Riverkeeper, and the Sierra Club.

The comments in the enclosed Joint Memorandum are supplemental to and incorporate by reference, the technical and scientific comments submitted under separate cover by the Louis Berger Group on behalf of all but the last of the above organizations.

Sincerely,

Wes Gillingham
Catskill Mountainkeeper

Maya van Rossum
the Delaware Riverkeeper, Delaware Riverkeeper Network

Deborah Goldberg
Earthjustice

Kate Sinding
Natural Resources Defense Council

Kate Hudson
Riverkeeper

Nathan Matthews
Sierra Club

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JOINT LEGAL MEMORANDUM ON THE REVISED DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM AND PROPOSED REGULATIONS FOR HORIZONTAL DRILLING AND HIGH VOLUME HYDRAULIC FRACTURING IN THE MARCELLUS SHALE AND OTHER LOW-PERMEABILITY RESERVOIRS

Introduction

This joint memorandum is being submitted on behalf of Catskill Mountainkeeper, Delaware Riverkeeper Network, Earthjustice, the Natural Resources Defense Council, Riverkeeper and Sierra Club, and is supplemental to, and incorporates by reference, the technical and scientific comments on the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Reservoirs, issued September 7, 2011 ("RDSGEIS"), and draft regulations (Proposed Express Terms 6 NYCRR Parts 52, 190, 550-556, 560, 750.1, and 750.3), issued September 28, 2011 ("Proposed Regulations"), submitted under separate cover by the Louis Berger Group on behalf of all but the last of the above organizations ("Technical Comments").

The purpose of this memorandum is to provide additional legal comments regarding the sufficiency of the RDSGEIS and Proposed Regulations. In sum, it is our conclusion that, although there have been notable improvements over the 2009 DSGEIS, crucial deficiencies remain that would render it not only unwise, but contrary to law, for the New York State Department of Environmental Conservation ("NYSDEC") to proceed with its proposed program regarding natural gas development using high volume hydraulic fracturing ("HVHF gas development") in the Marcellus shale and other low permeability formations. In particular, as discussed below and in the accompanying Technical Comments, a number of critical analyses fall short of what is required under the State Environmental Quality Review Act ("SEQRA"). Many of these deficiencies cannot be adequately addressed in a final SGEIS;[1] rather, new analyses must be prepared and issued for another round of public review and comment before the SGEIS can be finalized.

Further, the Proposed Regulations fall far short of what is required to responsibly regulate HVHF gas development in New York. In addition to analyses in the RDSGEIS that are incomplete or improper, appropriate mitigation is often neither identified nor set forth in the proposed regulations. Where mitigation *is* identified, but not codified in the proposed regulations, it violates the requirements of the State Administrative Procedure Act ("SAPA"). Our organizations strongly urge that – consistent with the spirit and intent of SEQRA and SAPA – NYSDEC refrain from issuing revised proposed regulations for public review until the environmental review process has been completed and a legally sufficient SGEIS issued.

[1] *See* Webster Assocs. v. Town of Webster, 59 N.Y.2d 220, 228 (1983) ("[T]he omission of a required item from a draft EIS cannot be cured simply by including the item in the final EIS.").

The Scope of the Proposed Action Described in the RDSGEIS Is Either Too Broad or the RDSGEIS Has Failed to Consider All Potential Significant Adverse Impacts

By including all low-permeability reservoirs within the scope of the RDSGEIS,[2] yet limiting review of actual impacts from HVHF gas development only to those that would result from drilling in the Marcellus shale, the RDSGEIS plainly fails to meet NYSDEC's own standard that Environmental Impact Statements ("EISs") must consider all significant adverse impacts within the defined scope of the action.[3] In this sense, either the scope of the RDSGEIS is overbroad, and the RDSGEIS must be expressly limited solely to drilling in the Marcellus formation, or the RDSGEIS has failed to address the entire scope of the project and impacts from HVHF gas development in other formations – such as the deeper Utica shale which both underlies and extends beyond the range of the Marcellus – must be evaluated.

SEQRA requires all agencies, including NYSDEC, to prepare or cause to be prepared an EIS for "any action . . . which may have a significant effect on the environment."[4] The EIS must include an appropriate "description of the proposed action and its environmental setting," as well as identify "any adverse environmental effects which cannot be avoided should the proposal be implemented."[5] This requires that the EIS "applies to the entire project" as described;[6] that the agency take a "'hard look" at all the relevant areas of environmental concern;" and that the agency take "those concerns into account "to the fullest extent possible."[7] Evaluating the environmental impacts of only a portion of the action described is contrary to the intent of SEQRA – all elements and phases of an action must be considered.[8] Where an agency fails to consider the entire scope of a project, its determination will be overturned.[9]

With respect to the RDSGEIS, NYSDEC fails either to accurately describe the action under review, or to properly consider the impacts of that action. While the RDSGEIS purportedly applies to development in the Marcellus shale as well as all "other low-permeability formations" in New York, the RDSGEIS' discussion of other formations, e.g., the Utica shale, is limited to mere mention of such without meaningful impact analysis,[10] and its inclusion in the evaluation of potential socioeconomic

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[2] RDSGEIS at 2-1 ("The proposed action is the Department's issuance of permits to drill, deepen, plug back or convert wells for horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale and other low-permeability natural gas reservoirs.").
[3] 6 N.Y.C.R.R. § 617.9(b)(1).
[4] Environmental Conservation LAW ("ECL")ECL § 8-0109(2).
[5] ECL § 8-0109(2)(a), (c).
[6] Town of Henrietta v. Department of Environmental Conservation, 76 A.D.2d 215, 223 (4th Dept. 1980).
[7] Glen Head-Glenwood Landing Civic Council, Inc. v. Town of Oyster Bay, 88 A.D.2d 484, 492 (1982) (citing to Schenectady Chems., Inc. V. Flacke, 83 A.D.2d 460 (3rd Dept. 1981) and Town of Henrietta, 76 A.D.2d at 223); Jackson v. New York State Urban Development Corp., 67 N.Y.2d 400, 416 (1986) (agency must look at relevant areas of environmental concern and take a "hard look" at them); H.O.M.E.S. v. New York State Urban Development Corp., 69 A.D.2d 222, 232 (4th Dept. 1979).
[8] *See* 6 N.Y.C.R.R. § 617.3(g)(1); GERRARD, ET AL., ENVIRONMENTAL IMPACT REVIEW IN NEW YORK, § 3.05(2)(b) (citing to DEC, Final Generic Environmental Impact Statement Including Final Regulatory Impact Statement and Final Regulatory Flexibility Analysis of Revisions to 6 N.Y.C.R.R. Part 617, Feb. 18, 1987, at 9–10).
[9] *See* Village of Westbury v. Department of Transportation, 75 N.Y.2d 62 (1989) (annulling a negative declaration for the widening of a highway interchange where it was found that the project was closely linked to the widening of a connecting highway there, and the impacts from that project were not considered); Karasz v. Wallace, 134 Misc. 2d 1052 (Sup. Ct. Saratoga Ct.) (reversing determination by town zoning board that no EIS was needed for just one apartment house where it was apparent that developers intended more buildings on the same site).
[10] Technical Comments, report of Harvey Consulting LLC ("Harvey Report"), Chap. 2, at 4–9.

benefits. There is no consideration whatsoever as to whether, and if so how, the impacts of HVHF gas development in other low-permeability formations could differ from those associated with development of the Marcellus shale. The RDSGEIS therefore has either failed to correctly describe "the proposed action and its environmental setting" or failed to identify all the "adverse environmental effects" which would occur "should [NYSDEC's] proposal be implemented."[11]

As demonstrated in the Technical Comments, the environmental concerns associated with drilling in the Marcellus shale are distinctive from those associated with drilling other formations, such as the Utica shale. For example, drilling in the Utica, which is almost twice as deep as the Marcellus, will require more resources and equipment, will generate more air pollution, drilling wastes, and transportation and surface impacts, and, given the higher pressure associated with deeper gas reservoirs, will involve an increased blowout risk.[12] In addition, low-permeability gas reservoirs present at depths shallower than the Marcellus and closer to water resources have not been studied at all.[13] Furthermore, the "environmental setting" of the Marcellus is different from that of other shales, such as the Utica. While the Utica underlies a great portion of the Marcellus, it also extends significantly beyond the Marcellus' geographic limit.

When applications are filed to conduct HVHF gas development in other formations, SEQRA demands that the unique and significant impacts associated with those applications must be given the requisite "hard look." Because the RDSGEIS fails to satisfy NYSDEC's responsibilities in this regard, NYSDEC must (1) expressly limit the scope of the RDSGEIS to match the scope of impacts actually considered – i.e., drilling in the Marcellus shale; or (2) issue a new revised DSGEIS for public comment which adequately identifies other formations where drilling will be permitted and assesses the relevant environmental impacts.

The RDSGEIS Fails to Justify Why It Does Not Consider the Impacts of Hydraulic Fracturing Using Between 80,000 and 300,000 Gallons of Water as High-Volume Hydraulic Fracturing

Although past versions of the DSGEIS suggested that hydraulic fracturing using between 80,000 and 300,000 gallons "may be considered high-volume,"[14] NYSDEC excludes such wells from consideration under the RDSGEIS and its Proposed Regulations. The RDSGEIS provides no justification for this change or its implicit conclusion that the impacts of such drilling have been adequately evaluated, and appropriate mitigation implemented, through the 1992 GEIS and existing regulations.

Because the purpose of the RDSGEIS is to consider new potential impacts from HVHF gas development not addressed by the 1992 GEIS, it focuses on distinct impacts associated with the process, such as those "associated with the large volumes of water required to hydraulically fracture horizontal shale wells."[15] To this end, the RDSGEIS defines "high -volume hydraulic fracturing" as fracturing that uses "300,000 gallons of water or more per well"[16] and excludes from consideration all wells which fracture using 299,999 or fewer gallons of water. The implication of this omission is that the impacts of such wells were adequately considered under the 1992 GEIS and are appropriately mitigated under the current oil and gas drilling regulations.

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[11] ECL § 8-0109(2)(a), (c).
[12] Harvey Report, Chap. 2, at 8.
[13] Harvey Report, Chap. 2 at 9.
[14] 2009 DSGEIS at 3-5.
[15] RDSGEIS at 2-1, 2-2.
[16] *Id.* at 2-1.

The 1992 GEIS, however, only evaluates hydraulic fracturing wells that use up to 80,000 gallons of water, and does not consider the impacts for wells which could use two to four times as much fluid to achieve fracturing.[17] Furthermore, the 2009 version of the DSGEIS provided that wells using between 80,000 and 300,000 gallons of water "may be considered high-volume" and that a potential applicant for such a well would have to "complete the portions of the EAF Addendum related to water source, fracture fluid makeup, distances, water wells and a fluid disposal plan."[18] Based on this modified EAF submission, NYSDEC would then determine, "based on potential impacts, to what extent SGEIS mitigation measures are required to satisfy SEQRA."[19]

NYSDEC provides absolutely no justification for its apparent determination that such well sites may no longer be considered high volume following site-specific review, or for its implicit reasoning that such wells are adequately considered under the 1992 GEIS and significant adverse impacts mitigated under the existing regulations. NYSDEC must either consider the impacts of such drilling in a reissued DSGEIS or else make clear that such drilling would not be permitted without an additional GEIS assessing the relevant impacts or a site specific SEQRA review for each well site.

The RDSGEIS Should Be Clear That It Only Applies to Hydraulic Fracturing Using Water and Not Other Substances

The RDSGEIS defines its scope as applying to horizontal or vertical wells "using 300,000 gallons of *water* or more per well."[20] That HVHF as defined by NYSDEC only applies to the use of water as the primary carrier fluid is supported by the proposed regulatory definition of HVHF.[21] Although the RDSGEIS does not purport to apply to fracturing with other types of substances – such as fracturing with propane gel as is already practiced in other states – NYSDEC should make abundantly clear that the SGEIS is not applicable to use of such other substances and that a separate SGEIS, or site-specific SEQRA review, would be necessary before permitting wells intending to fracture with such other substances.

The RDSGEIS Fails to Evaluate Potential Cumulative Impacts

The RDSGEIS fails to evaluate potential cumulative impacts as mandated by SEQRA and its implementing regulations. NYSDEC's SEQRA regulations require the preparation of a cumulative impact assessment when, even if no single project's impact is significant, the aggregated impacts from multiple actions may be significant.[22] This is consistent with the principle that all EISs "should deal with the specific significant environmental impacts which can be reasonably anticipated,"[23] including "primary

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[17] 1992 GEIS at 9-26 (considering only fracturing wells where "Twenty to eighty thousand gallons of fluid are injected into the producing formation under high pressure").
[18] 2009 DSGEIS at 3-5, 3-6.
[19] *Id.*
[20] RDSGEIS at 2-1 (emphasis added).
[21] Proposed 6 N.Y.C.R.R. § 560.2(b)(8) (defining HVHF as "the stimulation of a well using 300,000 gallons or more of water as the primary carrier fluid in the hydraulic fracturing fluid."); Proposed 6 N.Y.C.R.R. § 560.1(a) ("This Part applies to all vertical and directionally drilled wells, including horizontal wells, where high volume hydraulic fracturing is planned.").
[22] 6 N.Y.C.R.R. § 617.7(c)(2) ("agency must consider reasonably related long-term, short-term, direct, indirect and cumulative impacts"); 6 N.Y.C.R.R. § 617.9(b)(5)(iii)(a) (if applicable and significant, draft EIS must include "reasonably related short-term and long-term impacts, cumulative impacts and other associated environmental impacts").
[23] ECL § 8-0109(2).

(direct) and secondary (indirect) impacts"[24] as well as "short-term and long-term effects."[25] Consideration of cumulative impacts is especially important with respect to generic EISs that encompass broad statewide programs, such as NYSDEC's plan to permit HVHF gas development in the Marcellus shale.[26]

In our comments on the 2009 DSGEIS, we pointed out that the DSGEIS at that time utterly failed to assess cumulative impacts. While the RDSGEIS marks an improvement over the 2009 draft with respect to certain air quality impacts, the RDSGEIS still falls well short of considering the cumulative impacts which are reasonably foreseeable in many of the RDSGEIS' build out scenarios. To provide a few examples, the RDSGEIS excludes any meaningful analysis of: the cumulative impacts of land disturbance on water quality from multiple well pads;[27] the cumulative impacts of multiple well pads and pipelines with respect to wildlife habitat fragmentation;[28] the cumulative noise and vibration impacts of multiple wells being developed concurrently, as well as transportation-related noise on human health and wildlife;[29] the cumulative impacts of multiple well pads on sensitive visual resources;[30] and the cumulative impacts of well re-fracturing either at one or multiple wells.[31]

The failure to consider such significant and foreseeable impacts clearly violates the requirements of SEQRA and NYSDEC's own implementing regulations to prepare a meaningful cumulative impact assessment. Accordingly, NYSDEC must issue a further revised DSGEIS for public comment that includes adequate consideration of such impacts.

By Not Considering Impacts of Central Aspects of the HVHF Gas Development Process, the RDGEIS Improperly Segments Review of NYSDEC's Permitting Program

The RDSGEIS unacceptably segments review of NYSDEC's proposal to issue permits for HVHF gas development by failing to adequately consider impacts which result from the HVHF process itself and from the anticipated expansion of HVHF gas development in New York State. Under SEQRA, an EIS must consider the full range of environmental impacts associated with an action, including short term and long term impacts.[32] For proposals to permit actions which consist of a series of activities or steps, all of the activities and steps must be considered regardless of "whether the agency decision-making relates to

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[24] NYSDEC, The SEQR Handbook at 80 (2010).
[25] ECL § 8-0109(2)(b).
[26] 6 N.Y.C.R.R. § 617.10(e) (discussing generic EISs: "In connection with projects that are to be developed in phases or stages, agencies should address not only the site specific impacts of the individual project under consideration, but also, in more general or conceptual terms, the cumulative impacts on the environment and the existing natural resource base of subsequent phases of a larger project or series of projects that may be developed in the future. In these cases, this part of the generic EIS must discuss the important elements and constraints present in the natural and cultural environment that may bear on the conditions of an agency decision on the immediate project."). *Cf.* Save the Pine Bush, Inc. v. City of Albany, 117 A.D.2d 267, 270–272 (3rd Dept. 1986) (identifying generic impact statement as an appropriate form to consider cumulative impacts).
[27] Technical Comments, report of Meliora Environmental Design ("Meliora Report") at 5, 9–10, 13, 22–24.
[28] Technical Comments, report of Kevin Heatley, M.EPC ("Heatley Report") at 2–4, 16–14, 18–19.
[29] Technical Comments, report of Louis Berger Group, Inc. ("LBG Report"), §2.5, at 8.
[30] LBG Report, § 4.1, at 16–18.
[31] Harvey Report, Chap. 16, at 105–107.
[32] ECL § 8-0109(2).

the action as a whole or to only a part of it."[33] Contemplation of only a part of an action by an EIS is contrary to the intent of SEQRA.[34]

The overall HVHF gas development process involves a number of steps, including water withdrawals; rig construction; well drilling; fracturing; wastewater flowback; gas collection; compression and transmission; and ultimate recovery. Although many of these steps are considered in the RDSGEIS, central and significant steps in the process are glossed over or given mere lip service. The clearest example of such a step is wastewater disposal. The RDSGEIS notes that the return of millions of gallons of toxic and radioactive water, in the form of brines and flowback, is an unavoidable consequence of HVHF gas development activities.[35] It also acknowledges that "proper disposal of flowback from hydraulic fracturing will be necessary."[36]

Yet despite its recognition of the size and significance of impacts from fluid flowback, permissible treatment of the produced flowback water is not adequately addressed in the RDSGEIS or Proposed Regulations.[37] While the RDSGEIS discusses a number of short-term solutions to deal with flowback water on site[38] and does list various potential treatment options (such as the use of disposal wells and public and private water treatment),[39] the RDSGEIS fails to assess the foreseeable impacts associated with the possible treatment options that it identifies. These include the potential for seismic activity associated with deep well injection and air contamination and road infrastructure impacts that would be caused by out of state transport and disposal of waste. Impacts from treatment at publicly or privately owned treatment facilities, including those to receiving water bodies and from anticipated treatment technologies such as those in use in Pennsylvania and elsewhere, are also foreseeable and must be analyzed. Pledges to "promote reuse" of flowback water for fracturing in future wells[40] are laudable, but the impacts of reuse are similarly both foreseeable and inadequately evaluated, including impacts associated with the unavoidable ultimate disposal of reused, ultraconcentrated flowback.

Ultimately, the state has no plan for how to deal in-state with the inevitable generation of billions of gallons of wastewater containing toxic chemicals and radioactive materials should HVHF gas development be approved, and the possibility of shipping such volume of waste out of state is uncertain.[41] But the lack of such a plan does not excuse NYSDEC from developing a reasonable worst-case scenario – based at least in part on experiences in Pennsylvania, Ohio and elsewhere – that evaluates the impacts from the relatively conscribed, anticipated options for wastewater management.

The RDSGEIS also fails to evaluate other central and highly foreseeable results of a statewide plan for expanding gas drilling in New York, such as the construction of pipelines. The RDSGEIS does not analyze any of the significant impacts of pipelines (such as additional habitat fragmentation, stormwater runoff, etc.) based on flawed reasoning that such an analysis is not required because the

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[33] 6 N.Y.C.R.R. § 617.3(g).
[34] 6 N.Y.C.R.R. § 617.3(g)(1).
[35] RSDGEIS at 5-99 ("Flowback water recoveries reported from horizontal Marcellus wells in the northern tier of Pennsylvania range between 9 and 35 percent of the fracturing fluid pumped. Flowback water volume, then, could be 216,000 gallons to 2.7 million gallons per well"). For toxic characteristics of flowback water see RSDGEIS at 5-100 – 5-116.
[36] RSDGEIS at 5-84.
[37] *See* Technical Comments, report of Glenn C. Miller, Ph.D. ("Miller Report").
[38] RSDGEIS at 7-39 – 7-40.
[39] *Id.* at 7-63 – 7-66.
[40] RSDGEIS at 7-39.
[41] RSDGEIS at 5-132 ("The regulatory regimes in other states for treatment of this waste stream are evolving, and it is unknown whether disposal at the listed [out-of-state] plants remains feasible.").

pipelines would be reviewed under the Public Service Commission's Article VII process. The regulatory review process for pipelines is irrelevant – SEQRA requires state and local agencies to consider all reasonably foreseeable long term impacts of an action.[42]

By omitting meaningful consideration of central, unavoidable, and foreseeable aspects of the dramatic expansion of HVHF gas development in New York envisioned in the document, the RDSGEIS impermissibly segments review of the proposed action. NYSDEC must therefore issue a further revised DSGEIS that includes consideration of all such aspects.

The RDSGEIS Fails to Properly Evaluate the Impacts of Hazardous Wastes Produced During HVHF Gas Development

The RDSGEIS fails to adequately analyze the adverse environmental impacts that could be caused by the disposal of hazardous wastes produced during drilling, hydraulic fracturing, and production operations in New York State. Drilling muds, residual solids resulting from the treatment of flowback water, and any materials or equipment exposed to drilling muds, flowback, brines, or fluids used during HVHF gas development can contain "contaminants of concern," including acids, ammonia, benzene, formaldehyde, kerosene, and metals such as magnesium, barium, and stronium;[43] yet, the RDSGEIS neither examines the potential impacts of this toxic waste stream nor proposes any mitigation measures to protect human health and the environment from the risks posed thereby.

Although many HVHF gas development wastes satisfy the narrative criteria for hazardous wastes established under New York's ECL,[44] NYSDEC has categorically excluded all "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of . . . natural gas" from its regulatory definition of hazardous waste.[45] Consequently, those wastes are treated as ordinary solid waste or industrial waste, both of which are subject to less stringent environmental controls than hazardous waste.[46]

The ECL defines hazardous waste broadly, as "a waste or combination of wastes, which because of its quantity, concentration, or physical, chemical or infectious characteristics <u>may</u>: a. Cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness; or b. Pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, disposed, or otherwise managed."[47] Despite the statute's recognition of the toxic components of HVHF gas development wastes,[48] the RDSGEIS fails to determine whether such wastes may pose a substantial hazard to human health or the environment.

Further, following this analysis, and because the categorical exclusion of gas development wastes from the definition of hazardous waste is inconsistent with New York State law, NYSDEC should amend the Proposed Regulations to revise 6 N.Y.C.R.R. Part 371 to close the improper regulatory loophole and to require that, where HVHF gas development wastes meet the statutory criteria for hazardous wastes,

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[42] ECL § 8-0109. *See* Village of Westbury v. Department of Transportation, 75 N.Y.2d 62, 68–9 (1989); Long Island Pine Barrens Society, Inc. v. Town Board of Riverhead, 290 A.D.2d 448, 448–9 (2nd. Dept. 2002); Farrington Close Condominium Board of Managers v. Village of Southampton, 205 A.D.2d 623, 624–5 (2nd. Dept. 1994).
[43] *See* RDSGEIS ,at 5-101, Table 5.7.
[44] *See* ECL § 27-0901(3)(b).
[45] 6 N.Y.C.R.R. § 371.1(e)(2)(v).
[46] *See* RDSGEIS at 5-129 (classifying cuttings from mud drillings as "industrial non-hazardous waste").
[47] ECL § 27-0901(3)(b) (emphasis added).
[48] *See* RDSGEIS at 5-101, Table 5.7.

they are defined as such and are subject to all pertinent generation, transportation, treatment, storage, and disposal laws and regulations.

NYSDEC Must Address Potential Negative Socioeconomic Impacts in a Revised Socioeconomics Analysis Made Available for Public Comment Before Finalizing the SGEIS

A fundamental deficiency in the RDSGEIS, which NYSDEC recently acknowledged, is its failure to quantify any potential negative socioeconomic and community impacts.[49] This deficiency cannot be cured, given the significance of this omission, by addressing potential negative impacts in the FSGEIS.[50] A new draft socioeconomic analysis must be completed, and along with a revised RDSGEIS discussion of socioeconomic impacts based thereon, released with an additional public comment period before the SGEIS is finalized.

Although NYSDEC committed in its Final Scope for its RDSGEIS to consider "any potential positive or negative community impact, including potential environmental justice impacts,"[51] it failed to address all of the impacts directed by the Scope. A complete socioeconomic and environmental justice analysis requires examination of reasonably foreseeable impacts on noise; historic resources; aesthetic resources; traffic; short- and long-term population concentration, distribution, or growth; and community character, all of which are specifically protected by SEQRA.[52] Additionally, NYSDEC must assess the possible "creation of a material conflict with a community's current plans or goals as officially approved or adopted."[53] The Court of Appeals has held that failure to consider long-term effects on population patterns, community goals and neighborhood character is fatal to an environmental review under SEQRA.[54]

As detailed in the Technical Comments, NYSDEC's socioeconomic assessment is grossly insufficient. The RDSGEIS analyzes potential *economic benefits* of HVHF gas development, but provides little analysis and no quantification of the potential *costs* of HVHF development, such as increased public safety requirements, including emergency response measures, monitoring and inspection, and infrastructure maintenance.[55] The RDSGEIS also fails to consider Pennsylvania's experience, which has shown that there can be a "ramp up" of the transient population when gas production begins in a community, followed by a sudden drop off in which that population leaves and the permanent residents lose jobs and revenue.[56] Rather, the RDSGEIS assumes, contrary to evidence from other drilling states, that there will be a steady, predictable roll out of activity that will than slowly taper off and thus there will

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[49] Jon Campbell, *DEC takes closer look at community hydrofracking costs*, Ithaca Journal, Dec. 20, 2011, http://www.theithacajournal.com/article/20111220/NEWS01/112200346/DEC-takes-closer-look-community-hydrofracking-costs?odyssey=tab|topnews|text|FRONTPAGE (Commissioner Martens states: "We provided (Ecology & Environment) with feedback on areas that we'd like them to look at, and I think universally it was felt that some of the specific socioeconomic impacts should be expanded upon.").

[50] *See* Webster Assocs. v. Town of Webster, 59 N.Y.2d 220, 228 (1983) ("[T]he omission of a required item from a draft EIS cannot be cured simply by including the item in the final EIS.").

[51] NYSDEC, Final Scope for DSGEIS, § 4.9 (2011).

[52] *See* ECL § 8-0105 (6).

[53] 6 N.Y.C.R.R. § 617.7(c)(1)(iv).

[54] *See* Chinese Staff & Workers Assn. v City of New York, 68 N.Y.2d 359, 366-68 (1986) ("The potential acceleration of the displacement of local residents and businesses is a secondary long-term effect on population patterns, community goals and neighborhood character such that CEQR [City Environmental Quality Review, implementing SEQRA] requires these impacts on the environment to be considered in an environmental analysis.").

[55] *See* Technical Comments, report of Dr. Susan Christopherson ("Christopherson Report"), Part I.A.2, C.4.

[56] *Id.* at Part I.A.2.

not be any significant negative impacts.[57] For the RDSGEIS to pass muster under SEQRA, NYSDEC must address such omissions and erroneous assumptions.

The fact that NYSDEC has already acknowledged deficiencies and directed Ecology & Environment, Inc., its socioeconomics expert, to supplement its economic analysis highlights the significance of this gap in the RDSGEIS. As discussed above, NYSDEC cannot cure the firm's previous, completely inadequate report of the costs associated with HVHF gas development by supplementing that report in the FSGEIS. To comply with the requirements of SEQRA, NYSDEC must give the public an opportunity to review and comment on all supplemental analysis prepared by its consultant and revisions to the RDSGEIS based on those materials.

NYSDEC Should Propose Mitigation Measures Consistent with Comptroller DiNapoli's Approach to Addressing Potential Contamination Resulting from HVHF Gas Development

We concur with New York State Comptroller Thomas DiNapoli's determination that the RDSGEIS and Proposed Regulations fail to adequately address the issue of remediation of contamination resulting from HVHF gas development.[58] This significant gap led the Comptroller to submit legislation to create a Natural Gas Production Contamination Damage Recovery and Remediation Fund (Natural Gas Damage Recovery Fund),[59] recently introduced in the Assembly as A.8572 by Assemblyman Sweeney.

The need for a Natural Gas Damage Recovery Fund is clear based on the potential for significant contamination from natural gas operations. On April 19, 2011, in Bradford County, Pennsylvania, one of Chesapeake Energy Corporation's many HVHF wells had a catastrophic blowout, leading to contamination of nearby land and waterways with thousands of gallons of chemically-laden water.[60] Given the large number of oil and gas wells that have already been drilled in New York (70,000), and the additional 40,000 that New York is anticipating,[61] it is foreseeable that a similar event could occur here. As noted by Comptroller DiNaploi in his comment letter, "however careful the industry and regulators may be, accidents are inevitable."[62]

The Comptroller's recommended program, which is similar to the state's current Oil Spill Fund, would:

- Impose strict liability on owners or operators of drilling sites that cause contamination;
- Empower NYSDEC to order immediate clean-up by owner or operator or take over sites for immediate clean-up;
- Impose a surcharge on drilling permits to create the Natural Gas Damage Recovery Fund similar in structure to the existing Oil Spill Fund;
- Require oil and natural gas companies to post surety bonds to cover any shortfall between Fund resources and remediation costs.

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[57] *Id.*
[58] Letter from New York State Comptroller to Joe Martens, Commissioner, NYSDEC, Dec. 29, 2011, *available at* http://www.osc.state.ny.us/press/releases/dec11/NYSDEC_martens_letter.pdf.
[59] A. 8572, 234th Sess. (N.Y. 2011). A copy of the proposed legislation is available http://www.osc.state.ny.us/legislation/2011-12/oscb20.htm.
[60] *Gas Well Spews Polluted Water*, N.Y. TIMES, April 21, 2011, at A14 *available at* http://www.nytimes.com/2011/04/21/us/21frack.html.
[61] RDSGEIS at 6-6 (2011).
[62] Letter from New York State Comptroller to Joe Martens, Commissioner, NYSDEC, Dec. 29, 2011, *available at* http://www.osc.state.ny.us/press/releases/dec11/DEC_martens_letter.pdf.

- Direct DEC to maintain a public registry of sites affected by contamination resulting from natural gas production to enhance the ability of regulators to evaluate the effectiveness of industry regulation.

We applaud Comptroller DiNapoli for his bill and urge NYSDEC to support its passage. We recognize that the Comptroller's proposal would require legislative action and raise this issue not only to encourage NYSDEC's support of the Comptroller's bill, but to highlight our shared concern that the analysis of the potential for contamination in the RDSGEIS is lacking. The potential for damage to or destruction of public and private property, the environment and state natural resources resulting from contamination related to natural gas development presents a significant foreseeable cost associated with that activity. This potential impact should have been analyzed and assessed in the RDSGEIS and appropriate mitigation proposed.

Protections Proposed By The RDSGEIS For Areas Of Special Concern Are Inadequate

All areas of special concern for which NYSDEC has proposed drilling prohibitions focus solely on preventing site (surface) disturbance,[63] which mistakenly presumes that there are no subsurface contamination risks during the gas development process. However, as highlighted in the Technical Comments, HVHF gas development poses numerous risks with respect to subsurface migration of contaminants.[64] Contamination can also occur from, for example, potential long-term subsurface migration of contaminants.[65] NYSDEC should address this gap by prohibiting subsurface activity in all areas where surface activity is prohibited.

The RDSGEIS Does Not Prohibit Low-Volume Hydraulic Fracturing in Special Areas

All prohibitions proposed in the RDSGEIS apply only to *high-volume* hydraulic fracturing operations, i.e., those operations that use 300,000 gallons of water or more.[66] Operations that use less than this amount, whether traditional vertical wells or horizontal wells, would still be allowed in prohibited areas such as the New York City and Syracuse watersheds and would not be subject to any of the restrictions set forth in the RDSGEIS and Proposed Regulations. NYSDEC should address this regulatory gap by prohibiting both low- and high-volume hydraulic fracturing in these areas.[67]

Prohibited Buffer Areas Will Be Open for Drilling Reconsideration

Many of the state's "prohibited" buffer areas (e.g., those around primary aquifers, principal aquifers, public water supply wells, and tributaries thereto) include "reconsideration" provisions that would allow the state to consider permitting drilling in these areas and buffer zones within two to three (2-3) years of measuring "actual experience and impacts associated with permit issuance."[68]

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[63] Proposed 6 NYCRR §750-3.3(b).
[64] See, e.g., Technical Comments, report of Tom Myers, Ph.D. ("Myers Report") at 12-15.
[65] *Id.*
[66] RDSGEIS at 3-16.
[67] As noted above (*supra* at 3), NYSDEC has not properly evaluated the potential impacts of what it considers to be non-high-volume hydraulic fracturing (i.e., hydraulic fracturing that uses between 80,000 and 300,000 gallons of water), either in the RDSGEIS or the 1992 SGEIS. This is an error that needs to be corrected as explained above. Regardless, the prohibitions discussed in this section should apply to all gas development activities, including vertical and horizontal wells that use less than 300,000 gallons of water.
[68] RDSGEIS at 9-6.

This approach sounds dangerously like an open door to removing mitigation recommended as a result of the SEQRA process without any additional environmental review or public input, and without basis on the best available scientific evidence. These reconsideration provisions are, moreover, unjustified as they are dependent solely on the date of the issuance of the first HVHF gas development permit in New York. Without knowing the pace and scale of development (and the number of operations that would be evaluated), this date is an arbitrary foundation upon which the evaluation process is built. These reconsideration clauses should therefore be withdrawn and the prohibitions made permanent.[69]

Mitigation Proposed By The RDSGEIS to Protect New York's Drinking Water Are Fundamentally Inadequate

New York City and Syracuse Watersheds – Unfiltered Drinking Water Supplies

In order to ensure that the uniquely unfiltered New York City and Syracuse watersheds remain unscathed, NYSDEC should increase its proposed 4,000-foot buffer to preclude any horizontal drilling under these watersheds sufficient to account for the length of current or future horizontal well bores.[70] Moreover, it appears that vertical drilling and low-volume hydraulic fracturing would still be permitted in these areas, even though they present the same kinds of risks. NYSDEC should address these issues and clearly prohibit any activities related to natural gas development in *and under* these watersheds and buffer areas.

Water Supply Infrastructure

There are at least two major risks from drilling on or around water supply infrastructure, including tunnels, dams and aqueducts: (1) a threat that seismicity from drilling activities could jeopardize the stability of the tunnels themselves; and (2) a threat that fracking fluids or other contaminants could migrate from drilling sites into the tunnels via small cracks or fissures in the tunnel walls – potentially contaminating NYC's drinking water. The New York City Department of Environmental Protection's ("NYCDEP") extensive technical comments on the 2009 DSGEIS recommended a 7-mile buffer zone around NYC's aging and leaking water supply infrastructure.[71] These tunnels are already compromised; in fact, the Delaware Aqueduct has been leaking 30 million gallons of water per day for more than two decades. However, in a crucial oversight, the state is *not* proposing to put this infrastructure off-limits to new drilling.[72] Allowing unsafe drilling activities to occur near aging and vulnerable water supply infrastructure poses an unreasonable risk to public health and emergency preparedness.

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[69] Note that many of the proposed buffer areas and other prohibitions are in themselves inadequate, as addressed in NRDC's Technical Comments. See, e.g., Technical Comments, summary report of Louis Berger Group ("LBG Summary Report") at 6.

[70] See, e.g., Press Release, Chesapeake Energy Corporation, Chesapeake Energy Corporation Discloses Initial Horizontal Well Drilling Results in its Utica Shale Discovery and Announces Achievement of Corporate Production Milestones (Sept. 28, 2011), available at: http: http://www.chk.com/news/articles/pages/1610725.aspx (indicating that of Chesapeake's four completed lateral wells in the Utica Shale of Ohio and Pennsylvania, all extended horizontally over 4,000 feet and two extended over 6,000 feet).

[71] Hazen and Sawyer, Final Impact Assessment Report, December 2009, at D-3, available at: http://www.nyc.gov/html/dep/pdf/natural_gas_drilling/12_23_2009_final_assessment_report.pdf.

[72] NYSDEC proposed in the RSDSGEIS only to notify NYCDEP of any proposed well in counties containing New York City drinking water supply tunnels or aqueducts. RDSGEIS at 7-68. A proposed well would be subject to site-specific review if NYCDEP determined that the proposed well was within a 1,000-foot-wide corridor surrounding tunnels or aqueducts. *Id.*

NYSDEC's current plan makes no mention of protecting Syracuse's water supply infrastructure system; as with the NYC infrastructure, NYSDEC should prohibit drilling within a 7-mile buffer area around Syracuse's water supply infrastructure.

Public Drinking Water Supplies

Scientists recognize that current water filtration systems were not designed to filter out the wide range of chemicals expected to be used in HVHF gas development operations.[73] NYSDEC's proposed temporary, 2,000-foot buffer between HVHF operations and the surface of filtered public drinking water supplies (which is also subject to reconsideration after three years)[74] is inadequate.[75] Instead, NYSDEC should establish permanent, protective buffer areas in and around all watersheds (such as the Finger Lakes) that serve as public drinking water supplies.[76]

Private Drinking Water Supplies

NYSDEC proposes in the RDSGEIS and Proposed Regulations to prohibit well pad development for HVHF gas development within 500 feet of private drinking water wells and domestic use springs.[77] However, this "prohibition" can be waived by landowners.[78] There appear to be no procedural requirements for this waiver and no discussion in the RDSGEIS about how to address potential scenarios where well users may be tenants and/or other neighboring landowners who share the well and do not consent to the waiver. This waiver provision is unjustified and should be eliminated.

Primary and Principal Aquifers

According to NYSDEC's own guidance documents, the only difference between primary and principal aquifers is that primary aquifers are used intensively now and principal aquifers are, in effect, the potential primary aquifers of the future.[79]

Yet the RSDGEIS proposes to treat these aquifers differently, and does not provide adequate protection measures for either one. HVHF operations would be prohibited only on the surface of primary aquifers and within their corresponding 500-foot buffer zones, subject to reconsideration after 2 years.[80]

Principal aquifers fare even worse than primary aquifers under NYSDEC's plan as the Department proposes only to require site-specific review (which does not guarantee an additional environmental impact statement) for drilling on the surface of these potential water supplies.[81] NYSDEC

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[73] *See, e.g.,* Physician, Scientists and Engineers for Healthy Energy, Letter to Governor Andrew Cuomo, Sept. 15, 2011, available at: http://www.scribd.com/doc/65121866/Sign-on-Letter-Final.
[74] RDSGEIS at 7-73.
[75] *Id.*; proposed 6 N.Y.C.R.R. §750-3.3(b)(4).
[76] As noted above (*supra* at 10), NYSDEC should extend these prohibitions to include subsurface activity as well and the protection should be permanent and not subject to reconsideration after three years.
[77] RDSGEIS at 7-74; proposed 6 N.Y.C.R.R. §560.4(a)(1).
[78] *Id.*
[79] NYSDEC, Technical and Operational Guidance Series, 2.1.3, Oct. 23, 1990 at page 2, available at: http://www.dec.ny.gov/docs/water_pdf/togs213.pdf.
[80] RDSGEIS at 7-41; proposed 6 N.Y.C.R.R. § 750-3.3(b)(2).
[81] RDSGEIS at 7-40 and 7-41; proposed 6 N.Y.C.R.R. §750-3.21(f)(4) (noting that the SPDES HVHF General Permit would not cover operations within 500 feet of a principal aquifer as measured from the closest edge of the gas well pad).

should also establish buffers that explicitly prohibit surface and subsurface HVHF gas development activity on and under principal aquifers.

Mitigation Proposed by the RDSGEIS to Protect Other Special Resources Are Inadequate

Floodplains

Although NYSDEC proposes prohibiting surface disturbances within 100-year floodplains,[82] this approach is insufficiently protective and must be remedied. NYSDEC should also prohibit subsurface HVHF, as well as any activity related to HVHF gas development (infrastructure, holding ponds, etc.) in these areas.[83]

Not only does NYSDEC acknowledge that FEMA is currently updating Flood Insurance Rate Maps (FIRMs) in several high-flood areas in the state, but the Department also admits that the increased frequency and magnitude of flooding has raised concerns regarding the reliability of the existing FIRMs in the Susquehanna and Delaware River basins.[84] Given this acknowledgment, NYSDEC should extend this prohibition to 500-year floodplains.[85]

No permits should be issued anywhere in the state before updated floodplain maps are in place for the entire region and these maps are reflected in NYSDEC's environmental review and regulations. These maps should be reflective of anticipated changes that may result from climate change, namely the increase in frequency and severity of storm events.[86] To permit any HVHF gas development before properly mapping prohibited areas makes no sense as it could result in permitting activities to occur in prohibited areas that are not now, but may in the near future be classified as floodplains.

State Lands

NYSDEC has stated that HVHF gas development would not be allowed on State lands under its jurisdiction,[87] and given the potential for adverse impacts to forest habitat and wildlife identified in the RDSGEIS, this proposed protection is justified. However, NYSDEC should also prohibit drilling on *and under* all State-owned land under the Department's jurisdiction to ensure adequate protection.[88] Location of HVHF gas development ancillary facilities on state lands should also be prohibited.

NYSDEC also noted that land under the jurisdiction of the New York State Office of Parks, Recreation and Historic Preservation ("OPRHP") would be similarly protected under that agency's current policy.[89] However, in order to stand behind its commitment to fully protect state lands and parks, NYSDEC should prohibit drilling on and under all State-owned forests, reforestation areas, wildlife management areas reforestation areas, wildlife management areas, campgrounds, environmental

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[82] RDSGEIS at 7-76; proposed 6 N.Y.C.R.R. § 750-3.3(b)(3).
[83] For instance, proposed 6 N.Y.C.R.R. § 750-3.3(b)(3) defines "Construction phase" as "construction of access roads, wellpad, and other appurtenances," but "appurtenances" is not clearly defined in the draft regulations.
[83] RDSGEIS at 2-32, 2-33.
[84] RDSGEIS at 2-32, 2-33.
[85] *See, e.g.*, Myers Report at 24.
[86] *See, e.g.*, Technical Comments, report of Dr. Kimberly Knowlton ("Knowlton Report") at 2.
[87] RDSGEIS at 2-7 and 2-8.
[88] Accessing subsurface resources in these areas would clearly be allowed by NYSDEC. RDSGEIS at 7-101.
[89] RDSGEIS at 7-101.

education centers and public conservation easements, and formally encourage the OPRHP to promulgate similar rules.[90]

Other Areas

In addition to the areas that were specifically highlighted in the RSDSGEIS, NYSDEC should also evaluate other areas that, because of ecological, hydrological, recreational, and/or historic significance, should also be placed permanently off-limits to gas development.[91]

The Proposed Regulations Do Not Adequately Address the Need for Full Public Disclosure of Chemical Additives Used in HVHF Gas Development, Which Is Required to Assure Adequate Mitigation of Potential Significant Adverse Impacts

NYSDEC's goal of enacting a disclosure regime that will be "among the most stringent in the country"[92] is laudable, and we support the proposed requirement of pre-fracturing disclosure of hydraulic fracturing chemicals and mandatory use of safer alternative chemicals. Nonetheless, the proposed regime falls short of its stated goal in several key regards. The regime proposed in the RDSGEIS (1) fails to clearly require disclosure of each ingredient used in fracturing products, (2) uses an over-broad trade secret protection, and (3) does not make the disclosed information sufficiently available to the public. The NYSDEC should draw on the rules pending in or adopted by other states with respect to these issues and strengthen its proposed disclosure rules.

Prior Disclosure of Chemicals Should Be Required

Prior disclosure is an essential component of any effective disclosure regime. In general, disclosure must occur prior to the commencement of risk-generating activity; specifically, disclosure of fracturing fluid chemical additives must occur prior to drilling so that a baseline contamination level may be determined against which to assess the impacts of the industry's chemical usage on surface and groundwater quality as well as soil contamination levels. The RDSGEIS proposes to require prior disclosure as part of the SEQRA process, by requiring "identification of additive products, by product name and purpose/type, and proposed percent by weight of water, proppants and each additive" as an addendum to the EAF.[93] This key provision must remain in the final rule. Wyoming, a state with considerable oil and gas experience, has demonstrated the feasibility of mandatory prior disclosures.[94] Wyoming requires operators to file an application for permit to hydraulically fracture a well and to provide notice to nearby landowners. This application must disclose "the anticipated completion and stimulation program, including the base stimulation fluid and its source, the chemical additives and proposed concentrations to be mixed, identified by additive type . . . . If this required data is not available at the time of [the application], then it must be submitted [separately] and no stimulation of the well can

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[90] Protection should also be applied to NY's Recommended Open Space Conservation Projects and should recognize and incorporate the priorities set forth in New York's Open Space Plan.

[91] For instance, NYSDEC's 2008 determination that HVHF gas development warranted further review in an SGEIS was based primarily on the concern that drilling would potentially take place in or near the NYC Watershed, the Catskill Park, and the federally-designated Upper Delaware Scenic and Recreational River. While NYSDEC has proposed prohibitions for the NYC Watershed, the RDSGEIS and Proposed Regulations do not provide comprehensive protection for the Wild and Scenic Upper Delaware River or Catskill Park.

[92] RDSGEIS at 1-10.

[93] RDSGEIS § 8.2.1.2, *see also* proposed 6 N.Y.C.R.R. § 560.3(c) (requiring that an "application" include these disclosures without explicitly referring to the SEQRA process).

[94] Wyo. Admin. Code Oil Gen. Ch. 3 § 45.

occur without approval of the [regulatory agency]."[95] As discussed below, this pre-fracturing reporting must be promptly made available to the public, so that concerned citizens may, for example, engage in their own baseline testing before fracturing operations proceed in their vicinity. Without prior disclosure, baseline testing is impossible: one would not know for which chemicals to test. Without the ability to conduct baseline testing, it will be difficult if not impossible to establish causal responsibility when chemicals are discovered where they do not belong. Baseline testing equips potentially affected property owners, for example, with the information needed to deny polluters the illegitimate defense that "the contamination was there before we got here." If fracturing chemicals are safe, and leaks are unlikely, then there should be no resistance from industry to prior disclosure requirements.

Disclosure Must Be Comprehensive

Although the NYSDEC's proposal takes a strong stand regarding the timing of disclosures, the proposal is overly narrow in regard to the content of disclosure requirements.

Disclosure Must Provide a Basis for Risk Assessment

First, the proposal requires disclosure of "additive products."[96] As the proposed regulations acknowledge, additive products are typically composed of multiple chemical ingredients.[97] Identification of the underlying chemicals is of equal or greater importance than identification of the compound "additive product."[98] Disclosing the product's commercial name without its chemical composition is virtually useless for purposes of risk assessment. Not knowing the composition of the specific additives and the amount of each provides effectively no basis for estimating the risk of these constituents in contaminated water. The approach taken in the RDSGEIS will not be satisfactory with respect to prior disclosures. Tables 5.4 and 5.5 of the RDSGEIS use trade names, and while the New York regulators may have information on the constituents in those products, that information was not available for this review. Additionally, the public does not have access to the ingredient information withheld from the RDSGEIS, and thus the public cannot legitimately understand or evaluate the environmental or human health risks associated with these products.

New York should therefore follow Texas and Colorado in requiring disclosure both of "additive products" and separate disclosure of individual "chemicals."[99] For additive products, as with NYSDEC's proposals, Colorado and Texas require disclosure of, *inter alia*, "each hydraulic fracturing additive used in the hydraulic fracturing fluid and the trade name, vendor, and a brief descriptor of the intended use or function of each hydraulic fracturing additive in the hydraulic fracturing fluid."[100] Colorado and Texas

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[95] *Id.*, § 8(c)(ix).
[96] RDSGEIS § 8.2.1.2; proposed 6 N.Y.C.R.R. § 560.3(c)(1)(i).
[97] *See* proposed 6 N.Y.C.R.R. § 560.2(b)(2) ("'chemical additives' shall mean a product composed of one or more chemical constituents that is added to a primary carrier fluid to modify its properties in order to form hydraulic fracturing fluid."); § 560.2(b)(17) ("'product' shall mean a hydraulic fracturing fluid additive that is manufactured using precise amounts of specific chemical constituents and is assigned a commercial name under which the substance is sold or utilized.").
[98] See Miller Report.
[99] *See* 16 Tex. Admin. Code § 3.29(c)(1). Colorado is updating its disclosure requirements. The Colorado Oil and Gas Conservation Commission released a final draft for updated rules on December 13, 2011. Draft 2 Colo. Code Regs. § 404-1:205A(B)(2)(A)(IX)-(XII) requires disclosure of individual chemical constituents in addition to disclosure of additives. Wyoming's rules also require disclosure of additives as well as the Chemical Abstracts Number for individual chemicals, without explicitly discussing the relationship between these two requirements. *See* Wyo. Admin. Code Oil Gen. Ch. 3 § 45(d).
[100] Draft 2 Colo. Code Regs. § 404-1:205A(B)(2)(A)(XII); *see also* 16 Tex. Admin. Code § 3.29(c)(2)(ix).

exceed New York's proposal by also requiring disclosure of individual chemicals, identified by Chemicals Abstracts Service number, together with the applicable material data safety sheet ("MSDS"), if any, and a statement of the amount of the chemical used.[101]

Industry members and NYSDEC have expressed unwarranted concerns that linking individual chemicals with additive products would allow competitors to reverse engineer additive products. The Colorado Oil and Gas Conservation Commission explicitly responded to this concern by explaining that the rules require disclosure of all additives and all chemicals, but that each additive need not be tied to a specific list of chemical ingredients.[102] The Texas statute similarly bifurcates disclosure. NYSDEC's own study of the health effects of fracturing chemicals adopted this same approach, finding it sufficient to protect trade secrets.[103] The NYSDEC should take a similar approach to disclosure, and require disclosure of individual chemical constituents by Chemical Abstracts Service Number, including the amount of each chemical used.

The Disclosure Regime Must Close Existing Loopholes

Second, the NYSDEC should make the related clarification that disclosure obligations are not limited to chemicals for which a MSDS is available. Under the existing proposal, the absence of this requirement creates at least four loopholes that will frustrate the purposes of a disclosure regime. The RDSGEIS and Proposed Regulations confusingly state that a MSDS must be submitted "for every additive product proposed for use, unless the MSDS for a particular product is already on file . . . ."[104] The first loophole stems from the fact that many chemicals used in hydraulic fracturing, including many with potentially harmful effects, do not have an MSDS. Only "hazardous chemicals" need to be disclosed on MSDSs, and a chemical must have been subject to significant testing before it will be considered "hazardous" under the regulations.[105] The second loophole stems from the fact that there is no requirement that exploration and production chemicals ever be tested. Thus, hydraulic fracturing fluid may contain chemicals that are harmful to human health but that have not been tested to determine whether they meet the Occupational Safety and Health Act (i.e., MSDS) definition of "hazardous." The third loophole stems from the fact that even where a chemical that has been sufficiently tested qualifies as "hazardous," the manufacturer may opt not to disclose it on an MSDS if it constitutes less than one percent of the volume of the product (or 0.1 percent of the volume of the product if the chemical is a carcinogen).[106] The fourth loophole in the proposed disclosure regime stems from the fact that a "hazardous chemical" need not be disclosed on an MSDS if the manufacturer claims that its identity is a trade secret.[107] The manufacturer unilaterally may withhold specific chemical information as proprietary if it determines that the trade secret classification can be "supported."[108] Therefore, MSDSs alone are

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[101] *See* 16 Tex. Admin. Code § 3.29(c)(1); Draft 2 Colo. Code Regs. § 404-1:205A(B)(2)(A)(IX)-(XII).
[102] *See* Colorado Dept. of Natural Resources, Oil and Gas Cons. Comm'n, Amendments to 100 Series Definitions, 200 Series General Rules, 300 Series Drilling, Development, Production, and Abandonment Rules and 500 Series Practice and Procedure Rules, Statement of Basis, Specific Statutory Authority, and Purpose, 3-4, *available at* http://cogcc.state.co.us/RR_HF2011/FinalModifiedStaffProposal12_13_11V4.pdf.
[103] RDSGEIS at 5-62 ("The chemical constituents . . . are not linked to the product names . . . because a significant number of product compositions have been properly justified as trade secrets within the coverage of disclosure exceptions of the Freedom of Information Law [Public Officers Law §87.2(d)] and the Department's implementing regulation, 6 N.Y.C.R.R. § 616.7.").
[104] RDSGEIS § 8.2.1.2, proposed 6 N.Y.C.R.R. § 560.3(c)(1)(3).
[105] 29 C F.R. § 1910.1200(c).
[106] *Id.*, § 1910.1200(d)(5)(ii).
[107] *Id.*, § 1910.1200(g)(2)(i).
[108] *Id.*, § 1910.1200(i)(1)(i).

inadequate to identify the full spectrum of hydraulic fracturing chemicals or to evaluate the chemicals' health and environmental effects.

In light of these limitations of the MSDS system as applied to hydraulic fracturing, Colorado and Texas have explicitly required disclosure for chemicals which lack MSDS.[109] This single solution closes each of the four loopholes identified above. New York should follow these states' lead in explicitly requiring disclosure of all chemicals by Chemical Abstract Service number, regardless of whether the chemicals have been determined to be "hazardous" for purposes of the MSDS program.

Chemical Disclosure Requirements Should Apply to Drilling Mud

Third, disclosure should extend to every chemical introduced into the well. The proposed disclosure regime encompasses only hydraulic fracturing fluid.[110] Drilling combined with hydraulic fracturing requires the use of both fracturing fluids (which are used to create fractures in the formation, hold the fractures open to release the oil and gas, and stimulate well productivity) and drilling fluids (which are used to shorten drilling time and lubricate the drill bit). Fracturing fluids and drilling muds require similar classes of chemical additives, including proppants, acids, breakers, bactericides, biocides, clay stabilizers, corrosion inhibitors, crosslinkers, friction reducers, gelling agents, iron controls, scale inhibitors, and surfactants.[111] Because drilling mud uses similar chemicals as hydraulic fracturing fluid, it poses many of the same hazards to the environment and human health as hydraulic fracturing fluid, and should be subject to the same disclosure requirements.

Post-Fracture Reports Must Comprehensively Disclose Chemicals Actually Used

Pre-fracturing reporting should be followed by post-fracturing reporting of the chemicals actually used and the amounts thereof. New York currently requires some such information in the post-fracturing well completion report.[112] The RDSGEIS states that the completion report "can be utilized by Department staff to verify that only those additive products proposed at the time of application, or subsequently proposed and approved prior to use, were utilized in a given high-volume fracturing operation."[113] The RDGSEIS refers to the current completion report forms, but these forms are likely to be inadequate for this purpose. For example, the forms do not clearly require disclosure of the volumes of each additive used.[114] The proposed regulation, however, does appear to require disclosure of volumes of additives.[115] This requirement should remain in place. Moreover, the post-fracturing reporting should be broadened to include individual chemicals, identified by Chemical Abstract Service number and listed regardless of whether they are covered by an MSDS, as explained above. Wyoming, for example, already requires such reporting.[116]

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[109] Draft 2 Colo. Code Regs. § 404-1:100; 16 Tex. Admin. Code § 3.29(c)(1)(B).
[110] *See* RDSGEIS at 8.2.1.2, "Required Hydraulic Fracturing Additive Information."
[111] Ronald E. Bishop, Ph.D., Chemical and Biological Risk Assessment for Natural Gas Extraction in New York, 11 (Mar. 28, 2011) (stating that "most hydraulic fracturing additives are also used in drilling fluids (or 'muds')"). *See also* Harvey Report, Chap. 12. Note that the existing Colorado rule 205, which will remain intact after the proposed supplemental disclosure rule is enacted, requires disclosure of MSDS for all drilling muds. 2 Colo. Code Regs. § 404-1:205.
[112] 6 N.Y.C.R.R. § 544.7.
[113] RDSGEIS § 8.2.1.2.
[114] Available at http://www.dec.ny.gov/docs/materials_minerals_pdf/comp_rpt.pdf and http://www.dec.ny.gov/docs/materials_minerals_pdf/complrptinst.pdf, respectively.
[115] Proposed 6 N.Y.C.R.R. § 566.6(c)(26)(vii).
[116] Wyo. Admin. Code Oil Gen. Ch. 3 § 45(h)(ii).

Operators Should Be Required to Use the Safest Possible Chemical Additives

NYSDEC proposes to require that operators evaluate less-risky alternatives for the additive products used and to use such alternatives unless it is demonstrated that "they are not equally effective or feasible."[117] We offer tentative support for this provision. We note, however, that the qualifications "equally effective" and "feasible" invite dispute and may limit the efficacy of this rule. Under a strict reading, an operator may reject an alternative chemical additive that poses half the health risks of the original simply because it is 1% less effective. Accordingly, if NYSDEC insists on using this standard, it should explain that near-equivalent efficacy renders a safer alternative mandatory. Additionally, the term "feasible" invites dispute—any increase in operating cost that results from using a safer chemical alternative could provide illicit grounds for rejecting that alternative as infeasible; on the other hand, any chemical alternative that is not prohibitively expensive could be required because it is technically feasible.

In order to avoid the disputes and spurious interpretation of the ambiguous "equally effective or feasible" standard for adopting alternative chemical additives, NYSDEC should simply introduce the bright line rule that the safest chemical alternative must be utilized. The ability of a chemical to be detected and monitored should count as a positive feature, all things being equal, in weighing alternatives, since this will aid in environmental compliance and clean up. NYSDEC could further simplify the alternatives analysis by categorically determining whether certain chemicals or additives have equally effective alternatives, rather than leaving the alternatives analysis to piecemeal adjudication. Additionally, NYSDEC must seriously inquire whether chemicals that pose significant risks to the environment and human health, which have no safe alternative, are indispensible to hydraulic fracturing. If these chemicals are not necessary, then their use is patently unreasonable, and their use should be prohibited.

Trade Secret Rules Must Be Improved

The RDSGEIS provides little discussion of the treatment of purported trade secrets. The proposed regulations incorporate the general trade secret provisions found in 6 NYCRR § 616.7. We encourage NYSDEC to instead adopt the trade secret standards of the federal Emergency Planning and Community Right to Know Act ("EPCRA"). EPCRA's trade secret standards are particularly tailored to the context of potential environmental contaminants and provide a better fit for the issues arising from hydraulic fracturing.

The NSYDEC Should Incorporate the EPCRA Framework for Designation of Trade Secrets and Challenges to This Designation

As noted, EPCRA provides a trade secret regime well-suited to the problems presented by hydraulic fracturing. EPCRA authorizes public access, making clear that trade secret protections are available only in limited situations.[118] The relevant EPCRA regulations can be found at 40 C.F.R. Pt. 350 – a copy is attached. Though we recommend incorporating the majority of these rules by reference, a few are particularly important.

The first of these provisions is 40 C.F.R § 350.7 ("Substantiating claims of trade secrecy"). As its title suggests, this rule contains a detailed set of questions designed to flesh out the 42 U.S.C. § 11042 standards. For instance, it requires companies to carefully document earlier disclosures of material for

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[117] RDSGEIS at 8-29, proposed 6 N.Y.C.R.R. §§ 560.3(c)(1)(v), 750-3.4(b)(8).
[118] *See* 42 U.S.C. § 11042(b).

which they claim protection and to substantiate any claimed competitive harm in detail.[119] The regulation sets a useful standard for the type and quality of information New York should require in this important public health context. We urge New York to adopt it.

Similarly, 40 C.F.R. §§ 350.9-350.13 describe a reasoned decision-making process which the NYSDEC can use to rule on these claims. The NYSDEC should borrow from the federal system for its structure to ensure public trust is maintained by a valid process. The EPCRA rules lay out a detailed process that assures companies initial confidentiality while the process moves forward, *see* 40 C.F.R. § 350.9(a), while demanding that they carry a significant burden of proof if they are to maintain these claims, *see* 40 C.F.R. § 350.13. This "burden of proof rule" establishes unambiguous, strict standards for making these determinations. Without it, companies, the NYSDEC, and the public will not have a firm standard by which to settle confidentiality questions.

Finally, the rules defend the public's right to information. First, they require that the "adverse health effects" associated with each secret chemical be released to the public in all circumstances.[120] They also require companies to submit redacted versions of their confidentiality claims to the public in order to allow members of the public to petition for disclosure of any confidential information that they allege has been incorrectly classified as a trade secret.[121] Decisions on these petitions are judicially reviewable.[122] This system is crucial: It ensures that the public can assert its rights in the system, and will gradually develop judicial precedent that will help implement the rule.

New York could readily adopt these rules by incorporating them by reference, with minor amendments (such as making clear that appeals will be heard by the New York courts, and so on). We urge NYSDEC to make these improvements, which we believe can be done quickly and with ease.

Trade Secrets and Health and Environmental Emergencies

Whether or not NYSDEC follows our recommendation and adopts EPCRA's trade secret standards, NYSDEC should retain the proposal's requirement that all frack fluid constituents be divulged to NYSDEC, regardless of whether these fluids are protected as trade secrets.[123] Wyoming has adopted this approach.[124]

One benefit of this approach is that it facilitates emergency response. In the case of a health or environmental emergency, health care providers and other emergency personnel may need access to otherwise confidential information regarding fluid constituents. If this information is on file with the state, the state may provide a single contact point. Absent such prior filing, these individuals would have to determine whether the well operator, servicer, or additive supplier has the needed information, potentially delaying response.

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[119] *See, e.g.*, 40 C.F.R. § 350.7(a)(2); (a)(4); *see also* 40 C.F.R. § 350.27 (providing a standard form for companies to submit).
[120] 40 C.F.R. § 350.21.
[121] *See* 40 C.F.R. § 350.15.
[122] 40 C.F.R. § 350.17
[123] *See* proposed 6 N.Y.C.R.R. § 560.3(c)(2) (providing that the effect of trade secret designation will be that NYSDEC does not disclose secrets to the public).
[124] Wyo. Admin. Code Oil Gen. Ch. 3 § 45(f) (citing Wyo. Stat. Ann. § 16-4-203(d)(v)).

Public Access to Information

The RDSGEIS proposes two routes to public access of disclosed information. First, under existing rules, the applicant must notify "any local government affected" and "any landowner whose surface rights will be affected by drilling operations."[125] The NYSDEC should expand the distribution and content of this notification. As to distribution, the NYSDEC should explicitly state that affected surface rights include not just the rights of the landowner where the wellhead is situated, but the rights of all landowners near the lateral, whose groundwater may be at risk. Wyoming, for example, requires operators to notify surface landowners within half a mile of any point along a lateral.[126] Moreover, notice should not be restricted to landowners. Tenants, lessees, and others living within the affected area also deserve affirmative notification. The NYSDEC should further clarify the content of this notice. The existing statute merely requires notice "of the location of the drilling site." The NYSDEC should explicitly require that this notice include a copy of the documents disclosing fracturing chemicals or the address of a publicly accessible webpage where these documents may be found. In other words, these documents should be volunteered initially, such that local landowners, tenants, and other citizens will not be required to file a Freedom of Information Law request for every proposed well.

As a second route to public disclosure, the RDSGEIS "proposes to provide a listing of high-volume hydraulic fracturing additive product names and links to the associated MSDSs on an individual basis on [the NYSDEC's] website."[127] This proposal is not reflected in the proposed regulations. NYSDEC should follow others states' lead and codify the obligation for online disclosure.[128] Leaving aside the issue of codification, we support the NYSDEC's decision to use its own website rather than FracFocus.org, the industry-sponsored site many other states have relied upon. As recently explained by the Colorado Oil and Gas Conservation Commission, FracFocus.org suffers several crippling limitations, including limiting the ability to search for wells by area and aggregate information.[129] Data from chemical disclosures displayed online should be compiled in a database that is searchable at least by geographic area, ingredient, Chemical Abstract Service number, time period, and operator. The RDSGEIS's online disclosure proposal is limited because it appears to rest primarily on disclosure of MSDSs, whereas as explained above, the public should be informed of chemicals for which no MSDS exists.

The RDSGEIS Fails To Fully Consider Alternatives As Required Under SEQRA

The RDSGEIS contravenes SEQRA's requirement that every EIS discuss "alternatives to the proposed action."[130] As NYSDEC's own regulations specify, an EIS must include "a description and evaluation of the range of reasonable alternatives" to the proposed action.[131] Such an analysis is fundamental to SEQRA's substantive requirement that agencies "shall act and choose alternatives which, consistent with social, economic and other essential considerations . . . minimize or avoid adverse environmental effects."[132]

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[125] ECL § 23-0305(13); *see also* RDSGEIS 8.1.1.3 (discussing NY ECL § 23-0305(13)).
[126] Wyo. Admin. Code Oil Gen. Ch. 3 § 8(f)(ii).
[127] RDSGEIS at 8-30.
[128] *See* Draft 2 Colo. Code Regs. § 404-1:205A(b)(2)(3); 16 Tex. Admin. Code § 3.29(a)(7), (c)(2)(A), .
[129] *See* Draft 2 Colo. Code Regs. § 404-1:205A(b)(2)(3). The draft Colorado rule provides for disclosures via FracFocus.org in the short term, but identifies missing features that must be implemented by January 1, 2013. These features include allowing "commission staff and the public to search and sort the registry for Colorado information by geographic area, ingredient, chemical abstract service number, time period, and operator." *Id.*
[130] ECL § 8-0109.2(d).
[131] 6 N.Y.C.R.R. § 617.14(f)(5).
[132] E.C.L § 8-0109(1).

Although the statute and regulations do not require that every conceivable reasonable alternative be analyzed as part of the EIS process, the regulations stress that the EIS must examine "the range of reasonable alternatives to the action which are feasible."[133] In addition,"[t]he range of alternatives to be considered in a generic EIS is generally broader than in a site-specific EIS."[134]

The RDSGEIS' consideration of alternatives fails to meet these statutory requirements. In a 1,500 plus page document, the entire alternatives discussion is set forth in a mere ten pages. Within those pages, the only alternatives considered are a "No-Action Alternative," a "Phased Permitting Approach," and "'Green' or Non-Chemical Fracturing Technologies and Additives,"[135] each of which is inadequately addressed. Not only does the RDSGEIS fail to sufficiently examine these alternatives, it also fails to consider a number of other reasonable and highly plausible alternatives to the current proposal.

At a minimum, the RDSGEIS should consider the following alternatives: a "delayed action" alternative which examines the possibility of withholding action until 2014 when the state would have the benefit of additional information from EPA and other organizations; a "deference to local zoning alternative" that recognizes the right of municipalities to zone gas drilling activities; an "environmental hazard areas off-limits to drilling" alternative, recognizing the risk of drilling in environmentally hazardous areas and placing those areas – such as Superfund sites, hazardous waste sites, historic floodplains, and locations with risks from seismic activity – off-limits to drilling; a "demonstration project" alternative (distinct from the so-called "Phased Permitting Approach" alternative). that would involve permitting a limited number of wells (e.g., 100 annually) in a particular, suitable area for a pilot period; and a meaningful "green" technology alternative that evaluates the potential to require that HVHF operations use no or limited toxic chemicals.

NYSDEC's proposal as expressed in the RDSGEIS – which envisions as many as 1,484 or even 2,216 horizontal wells developed annually – could result in a sizable number of significant adverse environmental and economic impacts across much of New York State. Given the breadth of this project and its tremendous potential effect on the state, the narrow range of alternatives considered in the RDSGEIS is insufficient to satisfy SEQRA's requirement that a range of reasonable and feasible alternatives to the proposed action be considered.

NYSDEC Will Violate the State Administrative Procedure Act to the Extent That It Attempts to Enforce Mitigation Measures Contained in the RDSGEIS Which Are Not Contained in the Proposed Regulations

While a number of the proposed mitigation measures outlined in the RDSGEIS are incorporated into the draft regulations, many others are absent. For example, measures for conductor casing requirements, obligatory radiation surveys, and a host of measures related to noise, visual, and transportation impacts, all appear as proposed mitigation measures in the RDSGEIS, but have no enforceable counterpart in the Proposed Regulations.[136]Holding aside the question of the adequacy or appropriateness of these proposed measures (some of which are addressed below, and many of which are addressed in the accompanying Technical Comments), they appear to be intended as rules, which under New York State law are defined as "fixed, general principle[s] to be applied by an administrative agency

[133] 6 N.Y.C.R.R. § 617.9(b)(5)(v).
[134] GERRARD ET AL., ENVIRONMENTAL IMPACT REVIEW IN NEW YORK, § 5.14[2][a] (Matthew Bender).
[135] RDSGEIS, Ch. 9.
[136] Harvey Report, Chap. 5, at 15–16 (discussing conductor casing requirements), Chap. 19, at 141–42 (discussing radiation surveys); LBG Report, Table 2, at 10–12 (noise), Table 3, at 20–22 (visual), Table 4, at 31–35 (transportation).

without regard to other facts and circumstances relevant to the regulatory scheme of the statute it administers."[137] Accordingly, they require formal promulgation as regulations pursuant to SAPA, rather than reliance on imposition of discretionary permitting conditions and other *ad hoc* guidance documents as seemingly proposed by the RDSGEIS.[138]

NYSDEC has not indicated that it will propose new regulations pursuant to SAPA for mitigation measures not already contained in the Proposed Regulations released for comment on September 28, 2011. Nor are SEQRA's procedures a substitute for SAPA's.[139] Thus, unless NYSDEC goes through a formal SAPA rulemaking, it will be in violation of state law if it seeks to apply the new mitigation measures identified in the RDSGEIS as rules.[140]

On the other hand, if NYSDEC does not intend these measures to be binding as rules on all applicants, it cannot claim that they will function as legally required mitigation for the identified significant adverse environmental impacts of the proposed action. Should NYSDEC opt not to promulgate regulations under SAPA for the mitigation measures not currently addressed in the Proposed Regulations, these measures will not be codified and will be subject to *ad hoc* implementation, change on a case-by-case basis, and modification without public review or debate. Only properly promulgated regulations (or law-making) can ensure that this will not happen. As it stands, NYSDEC therefore cannot base its SEQRA analysis on the assumption that these mitigation measures will be fully implemented. As such, NYSDEC must reissue a draft of the Proposed Regulations for public comment which contains all mitigation measures from the RDSGEIS.

NYSDEC Should Initiate a Comment Period for the Proposed HVHF Gas Development Regulations After Issuing Its The Final SGEIS

NYSDEC's process of moving forward with permitting HVHF gas development in New York is fundamentally flawed because NYSDEC has issued for comment the Proposed Regulations prior to finalizing its SGEIS. Moreover, it currently plans to finalize the SGEIS and the Proposed Regulations simultaneously. By doing so, NYSDEC has denied New Yorkers the opportunity for their comments on the RDSGEIS to be considered in its drafting of the Proposed Regulations. A core principle of the state's environmental review process is that NYSDEC must finalize impact statements after incorporating public input and prior to taking an action so that the impact statement findings inform the action.[141]

By proceeding through the RDSGEIS and the regulation comment process simultaneously, NYSDEC has created a scenario in which modification of proposed mitigation measures between the

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[137] *E.g.*, Cubas v. Martinez, 8 N.Y.3d 611, 621 (2007).
[138] SAPA § 201.
[139] *See, e.g.*, SAPA §§ 202(1), 202-a, 202-b (requiring submission of "a notice of proposed rule making to the secretary of state for publication in the state register" and issuance of "regulatory impact statement" and "regulatory flexibility analysis").
[140] *See* Matter of Schwartfigure v. Hartnett, 83 N.Y.2d 296, 301 (1994) (requirement of 50% setoff for certain overpayments of unemployment insurance benefits held to require rulemaking); People v. Cull, 10 N.Y.2d 123, 129 (1961) (holding Art. IV of the New York Constitution required that setting of speed limits pursuant to general statutory authority necessitated rulemaking).
[141] *See, e.g.*, Schenectady Chemicals v. Flacke, 83 A.D.2d 460, 463 (3rd Dept. 1981) ("[T]he substance of SEQRA cannot be achieved without its procedure, and . . . any attempt to deviate from its provisions will undermine the law's express purposes."); Matter of Town of Henrietta v. Department of Environmental Conservation of the State of N.Y., 76 A.D.2d. 215, 220 (4th Dept. 1980) (finding an environmental impact statement is "to be viewed as an environmental 'alarm bell'" whose purpose is to alert public officials to environmental changes before they take action).

RDSGEIS and the FSGEIS could result in changes to the Proposed Regulations implementing those mitigation measures after the close of the comment period on both. Yet, NYSDEC anticipates finalizing the regulations without any additional comment period. Contrary to the spirit and intent of SEQRA, NYSDEC is thereby robbing the public of the opportunity to comment on the actual regulations it ultimately proposes to promulgate. To cure this deficiency, NYSDEC must provide the public with a meaningful opportunity for comment on the proposed HVHF regulations after issuing the FSGEIS.

NYSDEC's Proposed Regulations Fail to Provide for Public Participation in the HVHF Permitting Process

The RDSGEIS fails to provide a clear and accessible process for the public to weigh in on HVHF gas development permitting decisions. NYSDEC should revise its Proposed Regulations to provide for public participation in the HVHF permitting process. In the Oil, Gas and Solution Mining Law, the Legislature declares its intent to regulate the "development, production and utilization of natural resources of oil and gas in this state in such a manner . . . that the correlative rights of all owners and the rights of all persons including landowners and the general public may be fully protected."[142] Due to HVHF's heavy industrial nature and the possibility of siting well pads and ancillary facilities in residential areas, to implement this mandate, NYSDEC should integrate the public into the well permit decision-making process.

Public participation is a standard component of other permitting processes under the Uniform Procedures Act ("UPA").[143] Pursuant to the UPA's implementing regulations,[144]public notice and comment is required for all "major projects." A "major project" is defined as "any action requiring a permit" that is identified in the UPA, with limited exceptions.[145] It is fundamentally inconsistent from a policy perspective that the public will be able to comment on, for instance, the dam safety permit for a freshwater impoundment that a drilling company may need because such permit is listed in the UPA, but not on the drilling permit itself.

NYSDEC's Proposed Regulations modify existing drilling regulations in ways that make drilling operations subject to even less public and regulatory oversight. For example, applications for well spacing variances formerly automatically required NYSDEC to schedule a public hearing on the variance; under the Proposed Regulations, the default is for NYSDEC to grant the variance request, and a public hearing would only be scheduled if, after a 15 day comment period, the DEC determined that substantive and significant issues were raised.[146] Under the previous regulatory program, a written permit application was required to deviate a vertical well—to drill directionally—and the NYSDEC's receipt of such an application would trigger a compulsory ten-day waiting period for objections; if objections were received or if NYSDEC was not in accord with the deviation, a public hearing would be scheduled to determine whether directional drilling should take place.[147] Under the Proposed Regulations, no provision for review or public hearing is made; operators must simply notify the NYSDEC of their intention to deviate a vertical well and provide a follow-up angular deviation and directional survey within thirty days of doing so.[148] With respect to spacing unit variance applications and applications to directionally drill, the NYSDEC's Proposed Regulations severely limit the role of public participation and also limit NYSDEC's authority to review major drilling operation decisions before they are made.

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[142] ECL § 23-0301.
[143] ECL § 70-0109.
[144] *See* 6 N.Y.C.R.R. § 621.7.
[145] 6 N.Y.C.R.R. § 621.2(r).
[146] *See* 6 N.Y.C.R.R. Part 553.4(a)-(b).
[147] *See* 6 N.Y.C.R.R. Part 554.5(d); 554.5(g); 554.5(f).
[148] *Id.*

Neither NYSDEC's current oil and gas regulations or the Proposed Regulations provide a mechanism for meaningful public input in the permit decision-making process. NYSDEC should require public notice of the availability of HVHF gas development permit applications locally through publication of a notice in a newspaper of general circulation and statewide through a centralized website. The public should have immediate online access to all supporting documentation submitted with each permit application and at least a 30-day timeframe within which to comment on the permit application. Major operational changes such as spacing unit variances and permits to directionally drill a vertical well should allow for public participation as they did under the original regulatory program.

NYSDEC's Proposed SPDES General Permit for HVHF Stormwater Discharges Also Fails to Provide for Public Participation

The lack of public participation in the proposed draft SPDES General Permit for Stormwater Discharges ("General Stormwater Permit" or "Permit") is also a serious deficiency. The ECL specifically requires public notice of, and an opportunity to comment on, applications for SPDES permits, including permit renewals.[149] Yet, the draft General Stormwater Permit only requires NYSDEC to post Notices of Intent to obtain permit coverage ("NOI") on its website, and fails to provide for meaningful review of each NOI, i.e., a minimum 30-day public comment period after the NYSDEC publishes the NOI on its website. This violates the federal Clean Water Act ("CWA"), which guarantees the public an opportunity to participate "in the development, revision, and enforcement of any regulation, standard, effluent limitation, plan or program established by [EPA] or any State under this chapter . . . ."[150]

In *Waterkeeper Alliance v. EPA*,[151] the Second Circuit held that the failure to provide for public comment on effluent limitations within applications for general NPDES permit coverage violated CWA § 101(e).[152] The issue before the court was whether concentrated animal feeding operation ("CAFO") operators could apply for a coverage under a NPDES General Permit after developing a site-specific "nutrient management plan," an individual protocol for minimizing effluents from each CAFO. After holding that the operators could, the court found that each nutrient management plan was the functional equivalent of an effluent limitation, thereby requiring public comment.

Just as the court in *Waterkeeper Alliance* required EPA to provide for public comment on site-specific protocols for minimizing effluents from CAFOs, here NYSDEC must provide the public a meaningful opportunity to comment on the proposed protocols in each HVHF Stormwater Pollution Prevention Plan ("SWPPP"). If it does not allow for public comment prior to granting coverage under a finalized Permit, NYSDEC will be in direct violation of CWA § 101(e). NYSDEC should cure this

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[149] ECL § 17-0805(1).

[150] 33 U.S.C. § 1251(e); *see also* 33 U.S.C. §§ 1342(a), 1342(b)(3), 1342(j) (requiring that states' SPDES programs include a public participation component).

[151] 399 F.3d 486 (2d Cir. 2005),

[152] Other Circuits have similarly upheld the public participation requirement in NPDES general permits. The Ninth Circuit in Environmental Defense Center, Inc. v. EPA, 344 F.3d 843, 856–58 (9th Cir. 2003) held that notices of intent to comply with a municipal separate storm sewer systems general permit are the "functional equivalents" of individual permit applications and require public participation. The Seventh Circuit, however, has held that a general permit for "construction activities" did not have to provide for public review. *See* Texas Independent Producers & Royalty Owners Association, et al. v. EPA, 410 F.3d 964 (7th Cir. 2005). This case is inapposite, however, because the general permit at issue in that case had already established "specific requirements" for permittees, unlike the General Stormwater Permit, in which the specific requirements for drillers will be developed in their own SWPPPs. *See id.* at 968.

deficiency by incorporating a provision for public comment on all SWPPPs into the General Stormwater Permit.

NYSDEC Does Not Have the Regulatory and Enforcement Resources to Implement Its Proposed HVHF Permitting Program Responsibly

A fundamental flaw in NYSDEC's proposed HVHF gas development regulatory scheme is that NYSDEC does not have adequate resources to implement and enforce its proposed statewide program for permitting HVHF in the Marcellus shale. Despite this, NYSDEC has indicated that it may issue HVHF permits as soon as it finalizes the SGEIS.

NYSDEC itself has acknowledged that it does not have the resources required. NYSDEC issued a report on August 16, 2011, which concludes that NYSDEC does not have the necessary regulatory and enforcement staff in place to initiate HVHF permitting successfully, i.e., in a manner that is environmentally protective and economically beneficial.[153] Indeed, NYSDEC currently has only 13 staff statewide dedicated to oil and gas regulation, including permitting, compliance and enforcement.[154] While acknowledging this shortcoming, NYSDEC also estimates significant well development within five years from the commencement of HVHF permit issuance, projecting as many as 1,300 HVHF permit applications at 650 well pads by the fifth year of activity.[155] This is in line with Pennsylvania's experience, where, after a slow start to HVHF gas development in 2007, permitting activity quickly accelerated; in 2010, the Pennsylvania Department of Environmental Protection (PA DEP) issued 3,314 permits.[156]

Based on these projections, NYSDEC has estimated that it needs 142 positions in the short term, and 226 new positions in the first 5 years.[157] NYSDEC has also recognized that it does not currently have the funds to hire the new staff it needs, and it is unlikely to acquire these funds in the next budget cycle – Governor Cuomo has publicly acknowledged that no budget proposals related to HVHF gas development will be in the FY2013 Executive Budget. Even if NYSDEC was completely successful in achieving funding for HVHF gas development staffing in the FY2013 budget, budgeted funds will not be available until spring of 2013 and the earliest that NYSDEC could have staff in place is 2013, when it will have to begin the time consuming process of training that new staff. The more likely outcome is that NYSDEC will have staff in place, at the very earliest, in 2014, after the next budget cycle.

NYSDEC is not the only agency that will have significant resource needs to be able to provide the regulatory oversight necessary for a HVHF permitting program to move forward. The August 16 report explains that several other agencies will have additional workload and oversight responsibilities, including the Departments of Health, Public Service, Transportation, and Agriculture & Markets. In addition, a draft New York State Department of Transportation ("DOT") report strongly suggests that New York is not prepared to expend the resources required to address the expected impacts of HVHF on state and local roads.[158]

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[153] Advisory Panel on High-Volume Hydrofracking, State Resource Needs, at 2 (August 16, 2011).
[154] Karen McVeigh, *Fracking will poison New York's drinking water, critics warn*, The Guardian, Jan. 5, 2010, http://m.guardian.co.uk/environment/2012/jan/05/fracking-new-york-poison-claim?cat=environment&type=article.
[155] Advisory Panel on High-Volume Hydrofracking, State Resource Needs, at at 1.
[156] *Id.*
[157] Advisory Panel on High-Volume Hydrofracking, "DEC Staffing Needs" spreadsheet.
[158] N.Y. STATE DEP'T OF TRANSP., DRAFT DISCUSSION PAPER; TRANSPORTATION IMPACTS OF POTENTIAL MARCELLUS SHALE GAS (2011) *available at* http://www.un-naturalgas.org/NYSDOT%20Transportation%20Impacts%20Paper.pdf.

NYSDEC should not move forward with HVHF permitting in New York State in the absence of adequate regulatory and enforcement resources. Indeed, to do so would not only be bad policy, it would undermine SEQRA in that identified mitigation for identified significant adverse impacts would be unlikely to be adequately implemented or enforced. NYSDEC has indicated that it will pace permitting of HVHF activities according to the ability of staff to oversee development of those wells and ensure the protection of public health and the environment. But this is a political promise, not a guarantee, and with a change in administration, the agency's policy on this could easily change as well. NYSDEC has also pledged, "[n]o permits will be issued until NYSDEC has the proper enforcement capacity in place to monitor all fracturing activities."[159] We recommend that NYSDEC honor this promise and not issue any permit until it has adequate agency staffing place to process and enforce all aspects of the permit.

NYSDEC's Proposed Regulations Fail to Provide for Denial or Revocation of HVHF Permits Based on a Pattern of Noncompliance

Another critical flaw in NYSDEC's Proposed Regulations for HVHF gas development is that they provide no means for NYSDEC to deny or revoke permits based on a particular company's history of noncompliance with applicable law, regulation or permit conditions. We recommend that NYSDEC revise its regulations to include provisions similar to those promulgated under the UPA, which give NYSDEC the right to deny, suspend, modify or revoke permits for, *inter alia*, materially false statements, failure to comply with permit conditions, or exceeding the scope of the permitted project.[160] Without similar provisions in HVHF permitting regulations, NYSDEC cannot protect New York from companies who chose to engage in purposeful violations or environmentally harmful practices.

Such a provision is particularly needed in light of the low civil penalties available to enforce against HVHF gas development statutory, regulatory or permit violations. ECL Section 71-1307 sets penalties for the enforcement of Article 23 of the ECL, the state's mineral resources law. Pursuant to Section 71-1307(1), NYSDEC may not impose a civil penalty of more than $8,000 per violation, plus $2,000 per day for continuing violations. These penalties pale in comparison to the potential damage that HVHF could cause, and more importantly, do not act as a significant deterrent for companies that stand to reap profits exponentially greater than these amounts.[161] A key benefit of being able to deny or revoke permits based on a history of noncompliance is that this would enable a resource-strapped NYSDEC to curtail non-compliant regulatory conduct in a more effective way than by pursuing multiple enforcement actions that result in minor penalties.[162]

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[159] Press Release, NYSDEC, New Recommendations Issued in Hydraulic Fracturing Review, at 2 (June 30, 2011).

[160] 6 N.Y.C.R.R. §§ 621.10(f), 621.13(a).

[161] A recent *Greenwire* review of enforcement data throughout the largest drilling states shows that, in most places, only a small percentage of violations result in penalties, and the penalties that are levied are often insignificant. Pennsylvania, the most aggressive about violations, only sought penalties for about a quarter of the violations found in 2010, and levied penalties for 4 percent of the violations. The largest of those was a $900,000 penalty against a drilling company that contaminated the water of 16 homes. Greenwire reported that this amounted to less profits than the company in violation made in three hours. Mike Soraghan, *Puny fines, scant enforcement leave drilling violators with little to fear*, Env't & Energy Publishing, LLC, Nov. 14, 2011, www.eenews.net/public/Greenwire/2011/11/14/1.

[162] Such a provision would also bolster NYSDEC's authority to take administrative steps to stop drillers' ongoing violations. Currently, NYSDEC can order an immediate suspension of drilling operations in violation of the law, but drilling operators have the right to challenge NYSDEC's order in court immediately, and may be able to resume drilling operations as early as three business days following NYSDEC's order. *See* ECL § 23-0305(8)(g).

Conclusion

For the foregoing reasons, the RDSGEIS and Proposed Regulations contain a significant number of crucial deficiencies that require that NYSDEC conduct new and/or proper analyses and issue another RDSGEIS for public review and comment prior to proceeding to permit HVHF gas development in New York State.

Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation

Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews

Introduction

Natural gas currently provides 24% of the energy used by homes and businesses in the US (1). It is also an important feedstock for the chemical and fertilizer industry. In the early 1990's the price of natural gas was low (around \$3/1000 ft^3) and as a result there was a surge in construction of natural gas plants (2). Today, the Henry Hub price of natural gas is around \$15/1000 ft^3 (3), and most of these plants are operating below capacity. However, natural gas consumption is expected to increase 41% by 2025 (to 30 trillion cubic feet), with demand from electricity generators growing the fastest (increasing 90% by 2025). At the same time natural gas production in North America is expected to remain fairly constant at around 24 trillion cubic feet, so that demand of imported liquefied natural gas (LNG) will increase to around 6 trillion cubic feet or 20% of the total supply by 2025 (3).

The natural gas system is the second largest source of greenhouse gas emissions in the US, generating around 132 million tons of CO_2 Equivalents (1). Several studies have performed emission inventories for the natural gas lifecycle from production to distribution. Usually these analyses have been performed for domestic natural gas, so that emissions from the LNG lifecycle stages have been ignored. If, as the DOE estimates suggest, larger percentages of the supply of natural gas will come from these imports, emissions from these steps in the lifecycle could influence the total natural gas lifecycle emissions. Thus, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform an analysis of the natural gas lifecycle greenhouse gas emissions taking the emissions from LNG into consideration. Different scenarios for the percentage of natural gas as LNG are analyzed. Moreover, a comparison with the coal fuel cycle greenhouse gas emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

The Natural Gas Life Cycle

The natural gas life cycle starts with the production of natural gas and ends at the combustion plant. NaturalGas.org has a very detailed description of this life cycle. Readers are encouraged to visit this website if they need more information about the topic.

Geological surveys and seismic studies are used to determine the location of natural gas deposits. After these sites have been identified, wells are constructed. There are two types of well for the extraction of natural gas: oil wells and natural gas wells. Oil wells are

drilled primarily to extract oil, but natural gas can also be obtained. Natural gas wells are specifically drilled to extract natural gas.

After natural gas is extracted through the wells, it has to be processed to meet the characteristics of the natural gas used by consumers. Consumer natural gas is composed primarily of methane. However, when natural gas is extracted, it exists with other hydrocarbons such as propane and ethane. In addition, the extracted natural gas contains impurities such as water vapor and carbon dioxide that must be removed. Natural gas processing plants are usually constructed in gas producing regions. The natural gas is transported from the extraction sites to these plants through a system of low-diameter, low-pressure pipelines. At the plant, water vapor is first removed from the gas by using absorption or adsorption methods. Glycol Dehydration is an example of absorption, in which glycol, which has a chemical affinity to water, is used to absorb the vapor. Solid-Desiccant Dehydration is an example of adsorption. In this process the natural gas passes through towers that contain activated alumina or other solid desiccants. As the gas is passed through these towers, the water particles are retained on the surface of the solids.

As previously mentioned, natural gas is extracted with other hydrocarbons that must be removed. The removal of these hydrocarbons, called Natural Gas Liquids (NGL), is done with the absorption method or the cryogenic expander process. The absorption method is similar to the water absorption method, but instead of glycol, absorbing oil is used. The cryogenic expansion method consists of dropping the temperatures of the gas causing the hydrocarbons to condense so that they can be separated from the natural gas. The absorption method is used to remove heavier hydrocarbons, while lighter hydrocarbons are removed using the cryogenic expansion process.

The final step in the processing of natural gas is the removal of sulfur and carbon dioxide. Often, natural gas from the wells contains high amounts of these two compounds, and it is called sour gas. Sulfur must be removed from the gas because it is a potentially lethal chemical if breathed. In addition, sour gas can be corrosive for the transmissions and distribution pipelines. The process of removing sulfur and carbon dioxide from the gas is similar to the absorption processes previously described.

After the natural gas is processed it enters the transmission system. In the US, this transmission system is the interstate natural gas pipeline network, which consists of thousands of miles of high-pressure pipelines that transport the gas from producing areas to high demand areas. In addition to the pipes, this pipeline system has compressor stations along the way, usually placed in 40 to 100 mile intervals. These compressor stations use a turbine or an engine to compress the natural gas and maintain the high pressure required in the pipeline. The turbines and engines generally run with a small amount of the gas from the pipeline. In addition to compressor stations, metering stations are also placed along the system to allow companies to better monitor and manage the natural gas in the pipes. Moreover valves can be found through the entire length of the pipelines to regulate flow.

Natural gas can be stored to meet seasonal demand increases or to meet sudden, short-term demand increases. Natural gas is usually stored in underground facilities. Such facilities could be built in reconditioned depleted gas reservoirs, aquifers or salt caverns. According to the Energy Information Administration (EIA), in 2003 the total storage capacity in the United States was 8.2 billion cubic feet. 82% of this capacity was in depleted gas fields, 15% in depleted aquifers, and 3% in salt caverns. Moreover during that year, withdrawals from storage added to 3.1 billion cubic feet while injections totaled 3.3 billion cubic feet (4). It is important to note that some gas injected into underground storage becomes physically unrecoverable gas. This gas is known as base gas.

Distribution is the final step before natural gas is delivered to consumers. Local Distribution Companies transport natural gas from delivery points along the transmission system to local consumers via a low-pressure, small-diameter pipeline system. Natural gas that arrives to a city gate through the transmission system is depressurized, and filtered to remove any moisture or particulate content. In addition, Mercaptan is added to the gas to create the distinctive smell that allows leaks to be detected. Small compressors are used in the distribution system to maintain the pressure required.

When Liquefied Natural Gas (LNG) is added to the mix of natural gas, three additional lifecycle stages are created: liquefaction, tanker transport, and regasification. Figure 1 shows the total life cycle of natural gas including the LNG stages.

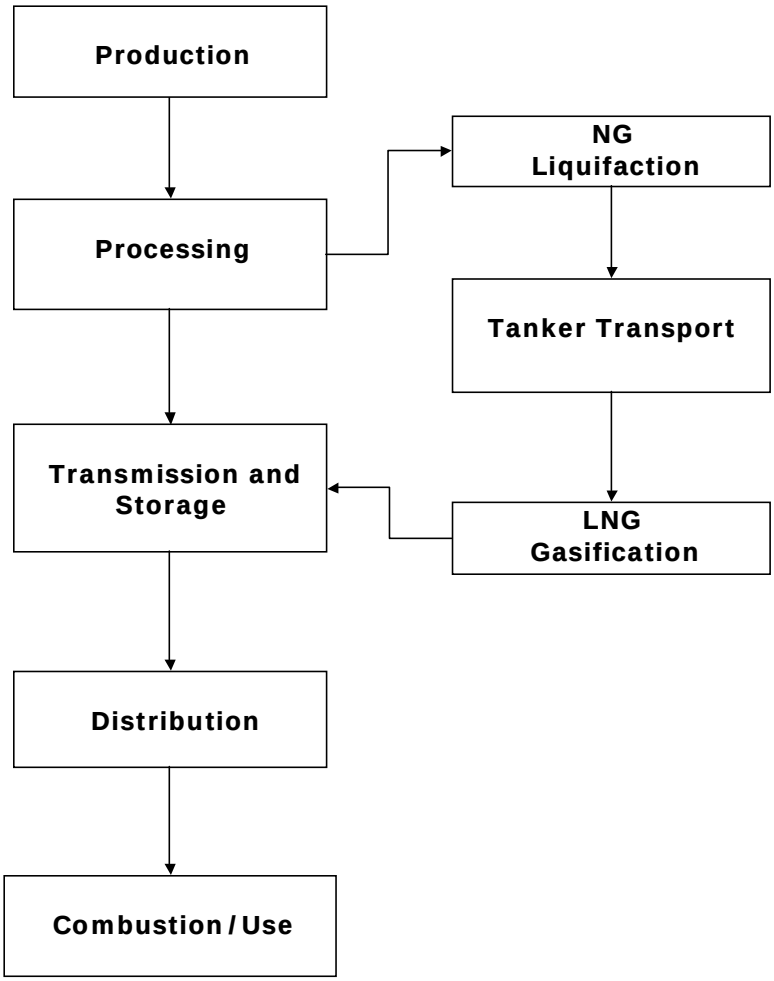

Figure 1: Natural Gas Life Cycle Including LNG.

In the liquefaction process, natural gas is cooled and pressurized to convert it to liquid form, reducing its volume by a factor of 610 (5). These liquefaction plants are generally located in coastal areas of LNG export countries. Currently 75% of the LNG imported to the US comes from Trinidad, but this percentage is expected to decrease as more imports come from Russia, the middle east, and southeast Asia (4). LNG tankers bring this gas to the US. According to EIA, there were 151 LNG tankers in operation worldwide as of October 2003. The majority of these tankers have the capacity to carry more than 120,000 cubic meters of liquefied natural gas (equivalent to 2.59 billion cubic feet of natural gas, enough gas to supply an average of 31,500 residences for a year (4)) and the total fleet capacity is 17.4 million cubic meters of liquid (equivalent to 366 billion cubic feet of natural gas). There are currently fifty-five ships under construction that will increase total fleet capacity to 25.1 million cubic meters of liquid (equivalent to 527 billion cubic feet of natural gas) in 2006 (6).

Regasification facilities are the last step LNG must pass through before going into the US pipeline system. Regasification facilities are LNG marine terminals where LNG tankers unload their gas. These facilities consist of storage tanks and vaporization equipment that warms the LNG to return it to the gaseous state. There are currently 5 LNG terminals in operation in the US: Lake Charles, Louisiana; Elba Island, Georgia; Cove Point, Maryland; Everett, Massachusetts; and a recently opened offshore terminal in the Gulf of Mexico. These terminals have a combined base load capacity of 3.05 billion cubic feet per day (about 1 trillion cubic feet per year). In addition to these there are over fifty proposed facilities for a total proposed capacity of 62 billion cubic feet per day (23 trillion cubic feet per year). Figure 2 shows the proposed location of these facilities (6).

As shown in Figure 1, natural gas combustion is the last stage in the natural gas lifecycle. In the US, natural gas is used for electricity generation, heating, and several industrial processes. Approximately 24% of the electricity generated comes from natural gas (1). Natural gas plants have heat rates that range from 5,800 BTU/kWh to 12,300 BTU/kWh (7).

US Natural Gas Industry in 2003

In 2003, the total supply of natural gas in the US was over 27 trillion cubic feet. Of this, 26.5 trillion cubic feet were produced in North America (US, Canada, and Mexico), and 0.5 trillion cubic feet were imported in the form of LNG. 75% of LNG came from Trinidad and Tobago. Other exporting countries included Algeria, Malaysia, Nigeria, Qatar, and Oman (4). Table 1 shows more detailed statistics about the state of the US natural gas industry in 2003. Numbers may not add up due to rounding.

Table 1: 2003 Natural Gas Industry Statistics (All units in million cubic feet) (4)

Gross Withdrawals	24,000,000
Total Dry Production	19,000,000
Total Supply	27,000,000
Total Consumption	22,500,000
Total Imports	4,000,000
Pipeline Imports	3,500,000
LNG Imports	505,000

Greenhouse gas emissions from Natural Gas produced in North America

During the late 1980’s and early 1990’s the US Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry. This very comprehensive study developed hundreds of activity and emissions factors from all the areas of the natural industry. These factors were developed using data collected from the different sectors of the industry as well as from data collected in field measurements. Table 2 presents the percentage of produced natural gas that is emitted to the atmosphere

during the lifecycle according to the results of the previously described study, as well as the source of these emissions.

Table 2: Methane Emissions from North American Gas Life Cycle as a Percentage of Natural Gas Produced (8).

Lifecycle Segment	Emission Sources	Emissions as a Percentage of Gas Produced
Production	Pneumatic Devices	0.38%
	Fugitive Emissions	
	Underground Pipeline Leaks	
	Blow and Purge	
	Compressor	
	Glycol Dehydrator	
Processing	Fugitive Emissions	0.16%
	Compressor	
	Blow and Purge	
Transmission and Storage	Fugitive Emissions	0.53%
	Blow and Purge	
	Pneumatic Devices	
	Compressor	
Distribution	Underground Pipeline Leaks	0.35%
	Meter and Pressure Stations	
	Costumer Meter	

Based on the statistics presented in Table 1, 26.5 billion cubic feet of natural gas were produced in North America in 2003. Using the percentages of natural gas emitted, an average heat content of 1,030 BTU/ft^3, and the assumption that 100% of the natural gas lost is methane (density 19.23 gr/ ft^3) which may result in a slight overestimate of emissions given that the real percentage of methane in natural gas varies between 94% and 98%; total methane emission were calculated to develop the emission factors shown in Figure 4.

In addition to methane, carbon dioxide emissions are produced from the combustion of natural gas used during the lifecycle stages previously described. The Energy Information Administration maintains records of the amount of natural gas used during the production, processing, transmission, storage, and distribution of natural gas. This data for 2003 can be seen in Table 3. Assuming that 100% of this gas is methane, total carbon dioxide emissions were found using thermodynamic calculations. These emissions were then added to methane emissions to obtain the total emission factors shown in Figure 3.

Table 3: Natural Gas Used During Natural Gas Life Cycle. (All units in million cubic feet) (4).

Flared Gas	98,000
Lease Fuel	760,000
Pipeline and Distribution Use	665,000
Plant Fuel	365,000

In 1993 the Natural Gas STAR program was established by the EPA to reduce methane emissions from the natural gas industry. The program is a voluntary partnership with the goal of encouraging industries to adopt practices that increase efficiency and reduce emissions. Since 1993, 338 billion cubic feet of methane have been eliminated. In 2003, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (9). This data was used to develop a range of emission factors for the North American natural gas industry. Figure 2 shows the total range of emission factors for the North American natural gas lifecycle. It can be seen that total lifecycle emission for natural gas produced in North America are approximately 140 lbs CO_2/MMBTU, an amount dominated by combustion emissions for natural gas plants currently in operation in the US of an average 120 lbs CO_2/MMBTU (10)

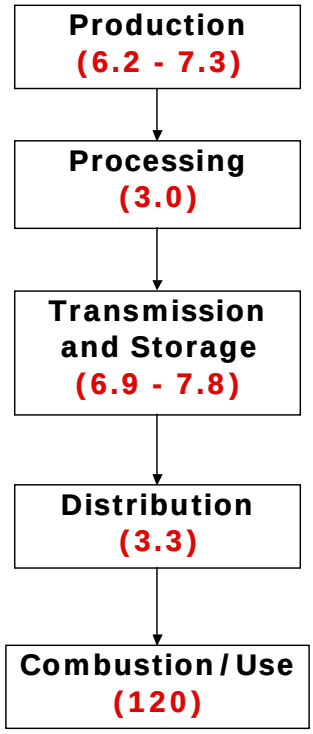

Figure 2: Carbon Dioxide Equivalent Emission Factors from North American Gas Lifecycle (All Units in lbs CO_2/MMBTU).

Greenhouse gas emissions from LNG lifecycle

As shown in Figure 1, the addition of liquefied natural gas (LNG) into the North American gas system introduces three additional stages into the lifecycle of natural gas: liquefaction, tanker transport, and regasification. It is assumed that natural gas produced in other countries and imported to the US in the form of LNG produces the same emissions in the production, processing, transmission, and distribution stages of the lifecycle as if the natural gas were produced in North America. Additional emission factors needed to be developed for the three additional lifecycle stages of LNG. Tamura et-al (11) has reported emission factors for the liquefaction stage in the range of 1.32 to 3,67 gr-C/MJ. Using these results, the emission factors for liquefaction were found in units of pounds of CO_2 per million BTUs, as shown in Table 4.

Table 4: Liquefaction Emission Factors.

Liquefaction	Emission Factors (lb CO_2/MMBTU)		
	Min	Average	Max
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Emissions from tanker transport of LNG were calculated using Equation 1.

$$EmissionFactor = \frac{(EF)\sum_x \left[\left(2 \times roundup\left(\frac{LNG_x}{TC}\right)\right) \times \frac{D_x}{TS} \times FC \times \frac{1}{24}\right]}{LNG_T}$$

Equation 1: Tanker Emission Factor.

Where EF is the tanker emission factor of 3,200 kg CO_2/ ton of fuel consumed; 2 is the number of trips each tanker does for every load (one bringing the LNG and one going back empty); LNG_x is the amount of natural gas (in cubic feet) brought from each country; TC is the tanker capacity in cubic feet of natural gas, assumed to be 120,000 cubic meters of LNG (1 m^3 LNG = 21,537 ft^3 NG); Dx is the distance from each country to US LNG facilities; TS is the tanker speed of 14 Knots; FC is a fuel consumption of 41 tons of fuel per day; and 24 is hours per day (12).

Exporting countries, their distances to the LNG facilities at Lake Charles, LA and Everett, MA, and the 2003 US imports can be seen in Table 5.

Table 5: LNG Exporting Countries in 2003 (4).

Exporting Country	Distance to Lake Charles Facility (nautical miles)	Distance to Everett, MA Facility (nautical miles)	2003 US Imports (million cubic feet NG)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

Emission factors for tanker transport from each country to both US facilities can be seen in Figure 3.

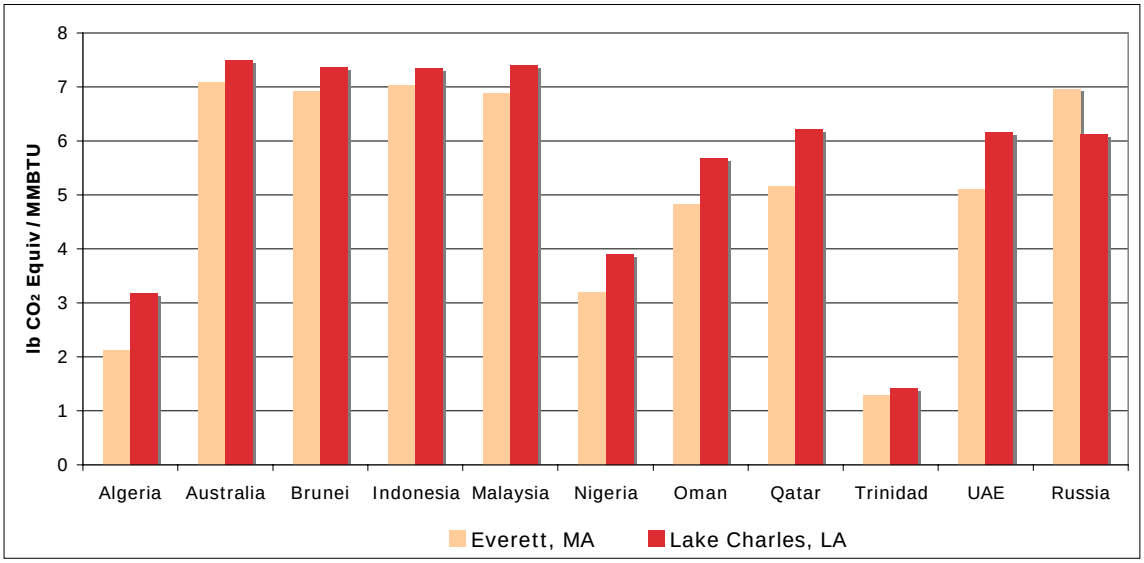

Figure 3: Tanker Emission Factors from Each Country

Since most of the LNG in 2003 was brought from Trinidad, the weighted average emission factor calculated for trips from each country to the Everett, MA facility is considered to be the a lower bound. An upper bound was obtained by assuming that all LNG was brought from Indonesia to the Lake Charles facility, and an average was obtained assuming all LNG was brought from Oman to the Lake Charles, LA facility. These resulting numbers can be seen in Table 6.

Table 6: Tanker Transport Emission Factors.

Emission Factors (lb CO_2/MMBTU)	
Min	1.8
Average	5.7
Max	7.3

Regasification emissions were reported by Tamura et-al to be 0.1 gr C/ MJ (0.85 lb CO_2/MMBTU) (11). Ruether et-al reports an emission factor of 1.6 gr CO_2/MJ (3.75 lb CO_2/MMBTU) for this stage of the LNG lifecycle by assuming that 3% of the gas is used to run the regasification equipment (13). These values were used as the lower and upper bounds of the range of emission from regasification of LNG. Total LNG lifecycle emissions are shown in Figure 4. They range between 154 and 184 lbs CO_2/MMBTU

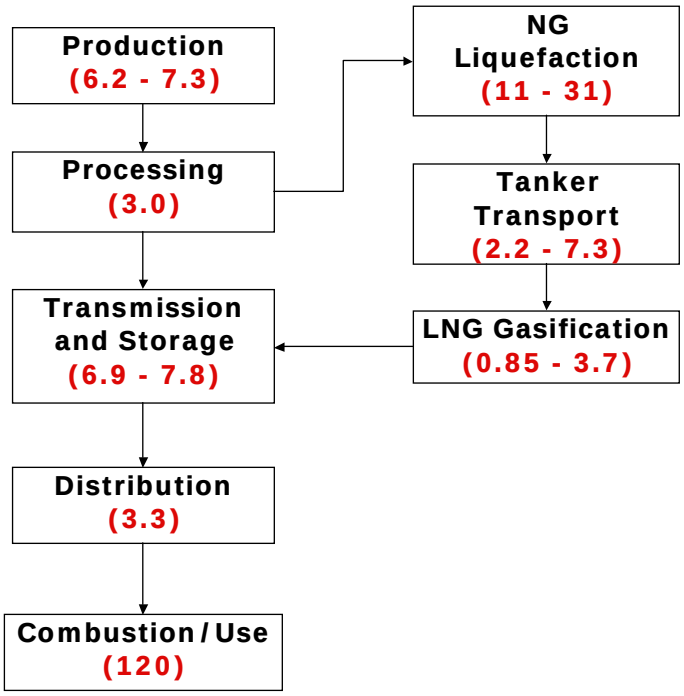

Figure 4: LNG Lifecycle Emission Factors (All Units in lbs CO_2/MMBTU).

Coal Lifecycle and its Greenhouse Gas Emissions for Electricity Generation

The coal lifecycle is conceptually simpler than the natural gas lifecycle, consisting of only three steps, as shown in Figure 5.

Figure 5: Coal Lifecycle.

In the US, 67% of the coal produced is mined in surface mines, while the remaining 33% is extracted from underground mines (1). Mined coal is then processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (14). Emissions from these lifecycle steps were calculated using the EIO-LCA tool developed at Carnegie Mellon University. In order to use this tool, economic values for each step of the lifecycle were necessary. In 1997, the year for which the EIO-LCA tool has data, the price of coal was $18.14/ton (15). Moreover, the cost for rail transport, barge, and truck transport was $11.06/ton, $3.2/ton, and $5.47/ton respectively (14). For a million tons of coal the following emission information was obtained using EIO-LCA.

Table 7: EIO-LCA Emission Data for Coal Lifecycle (16).

Sector	Total GHG Emissions (MT CO_2 Equiv)
Mining	75,000
Rail Transportation	36,000
Water Transportation	3,700
Truck Transportation	5,000

Using a weighted average US coal heat content of 10,266 BTU/lb (17) and the data previously discussed, it was found that the average emission factor for coal mining and transport is 11 lb CO_2/MMBTU.

In 1999, the National Renewable Energy Lab published a report on lifecycle emissions for power generation from coal (18). Upstream coal emissions (including transportation) from underground mines are reported to be 15 lbs CO_2/MMBTU, while upstream coal emissions from surface mines is 9.9 lbs CO_2/MMBTU. As previously mentioned, 67% of coal is currently mines in surface mines, while 33% is mined in underground mines (1). Using this information, the current coal upstream emissions average 12 lbs CO_2/MMBTU, which is very close to the emission factor obtained using EIO-LCA. In the future, the distribution of US mines could change, affecting the average emission factor. For this reason, the range of coal upstream emissions from underground and surface mines described above is used for this paper. Moreover, the average emission factors for coal combustion at utility plants used is 205 lb CO_2/MMBTU (10).

Comparing Natural Gas and Coal Lifecycle Emissions

Emissions factors for the natural gas lifecycle and the coal lifecycle were previously reported in pounds of CO_2 per MMBTU of fuel. Coal and natural gas power plants have

different efficiencies; thus one million BTU of coal does not generate the same amount of electricity as one million BTU of natural gas. For this reason, emission factors must be converted to units of pounds of CO_2 per kWh of electricity generated. This conversion was done using the heat rates of natural gas and coal plants. Figure 6 shows the distribution of these heat rates, and Figure 7 shows the resulting emission factor distribution for coal and natural gas. These distributions were obtained using the cumulative distribution function of EIA electricity generation data for all utility plants in 2003 (7). The minimum value represents the heat rate at which 5% of the electricity generated with the specific fuel is seen. Similarly the mean and maximum values are the heat rates at which 50% and 95% of the electricity has been generated with each fuel. As seen in Figure 6, the average heat rate for natural gas plants is lower than the average heat rate for coal plants, however the upper range of heat rates for natural gas plants surpasses the heat rates for coal plants.

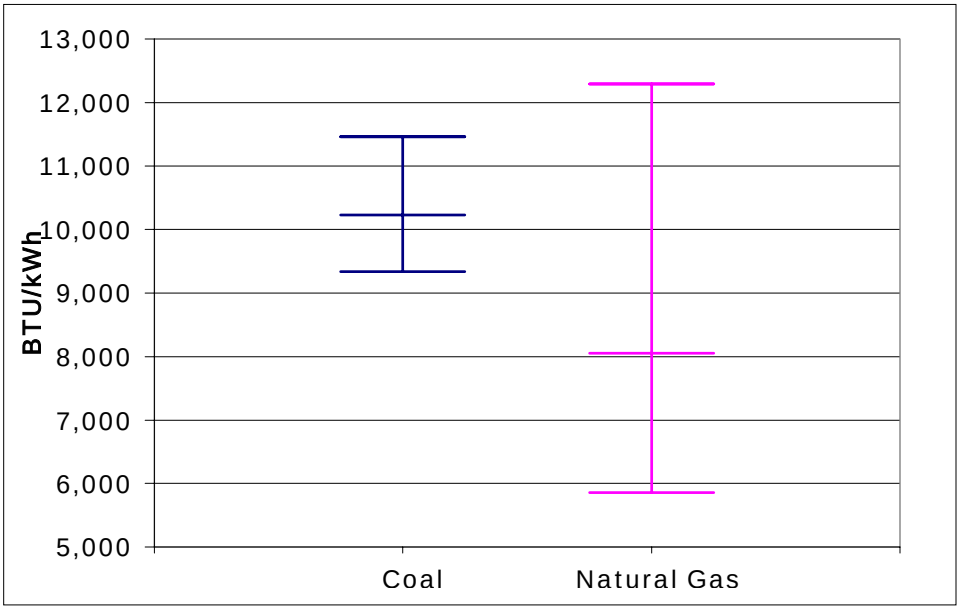

Figure 6: Natural Gas and Coal Plant Heat Rates (7).

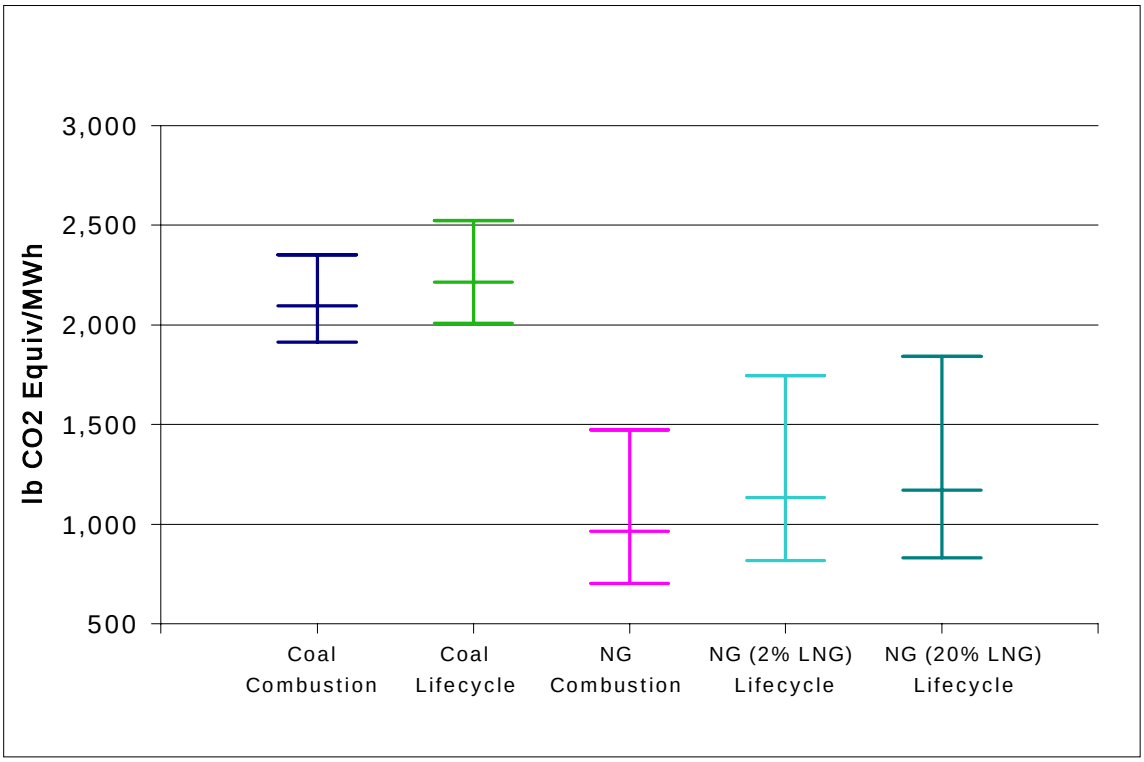

Figure 7: Emission Factors for Coal and Natural Gas Lifecycles.

Note that the average emission factor for coal combustion is higher than the emission factor for natural gas combustion. This does not change too much when the whole lifecycle is considered. More important seems to be the effect that including upstream emissions have in the range of emission factors for natural gas. While the average emission factor for the total coal lifecycle only increases by 5% compared to combustion emissions, the average emission factor for a natural gas mix with 20% LNG is 21% higher than the combustion emissions. Moreover, the maximum emission factor of the natural gas lifecycle gets closer to the minimum coal lifecycle emission factor. These results imply that if emissions at the combustion stage of the lifecycle could be controlled, natural gas would not be a much better alternative to coal in terms of greenhouse gas emissions.

New Generation Capacity

According to the DOE, by 2025 43 GW of inefficient gas and oil fired facilities will be retired, while 281 GW of new capacity will be installed (3). IGGC and NGCC power plants will probably be installed. These plants are generally more efficient than current technologies (average HHV Efficiencies are 37.5% and 50.2% respectively) (19) and thus have lower carbon emissions at the combustion stage. In addition, carbon capture and sequestration (CCS) can be performed more easily with these newer technologies. CCS is a process by which carbon emissions at the power plant are separated from other combustion products, captured and injected into underground geologic formations such as saline formations and depleted oil/gas fields. Experts believe that 90% CCS will be

technologically and economically feasible in the future. Having CCS at IGCC and NGCC plants decreases the efficiency of the plants to average HHV efficiencies of 32.4% and 42.8% respectively (19) but overall lifecycle emissions would be greatly reduced and would be essentially the same for coal and natural gas (with 20% LNG). However, the major contributor for coal emissions would be at the combustion stage, while for natural gas the majority of the emissions would come from upstream processes. Figure 8, shows total emissions with CCS for IGCC and NGCC plants using average upstream emission factors of 11.6 lbs CO_2 Equiv/MMBTU and 25.6 lbs CO_2 Equiv/MMBTU for coal and natural gas respectively

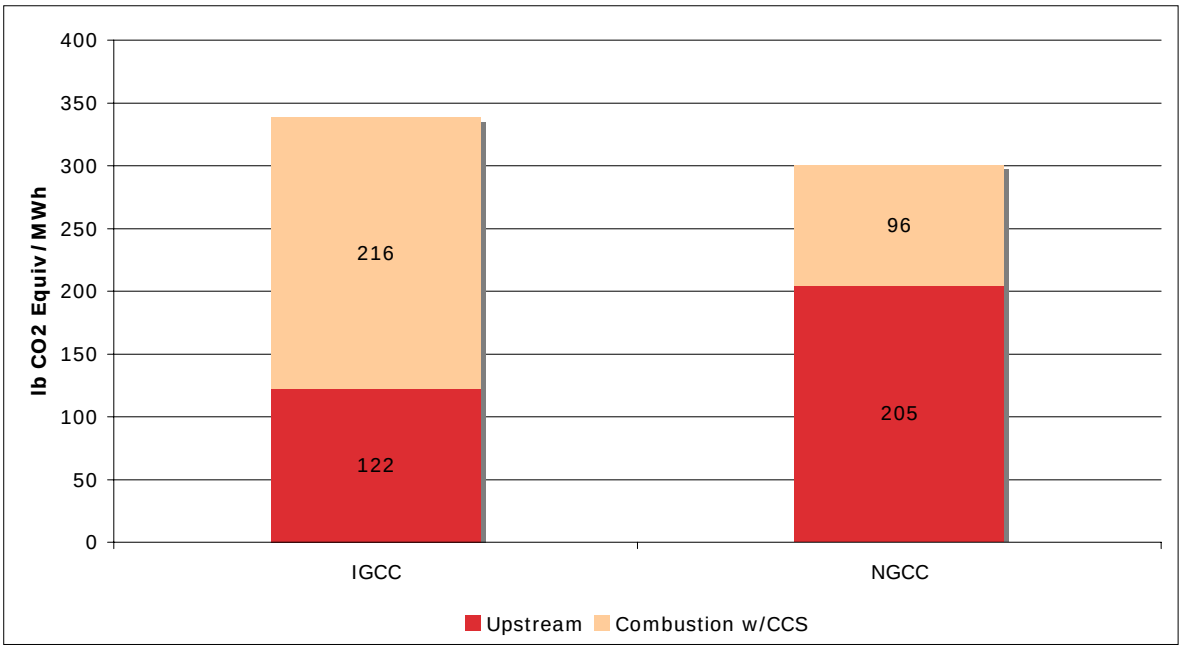

Figure 8: Lifecycle Emission Factors for IGCC and NGCC plants w/ CCS.

Discussion

It has been shown that there is high uncertainty about overall lifecycle carbon emissions for coal and LNG. In the future, as newer generation technologies and CCS are installed, overall emissions from electricity generated with coal and electricity generated with natural gas could be surprisingly similar. There is push right now from power generator to increase import of LNG. They seem to hope that the price of natural gas will decrease with these imports and they will be able to recover the investment they made in natural gas plants that are currently producing under capacity. These investments should be considered sunk costs and it is important to revaluate whether investing billions of dollars in LNG infrastructure will lead us into an energy path that cannot be easily changed as it will be harder to consider these investments as sunk costs once the expected environmental benefits are not achieved.

The analysis presented here only includes carbon emission, and no consideration was given to issues like energy security. Increasingly, LNG will come from areas of the world that are politically unstable. Policymakers should evaluate this increased dependence on foreign fuel before making decisions about future energy investments. In addition, the analysis presented only considers the use of natural gas for electricity generation. Natural gas is an indispensable fuel for many sectors of the US economy. As demand for natural gas from the electric utilities increases, these other sectors will probably be affected by higher natural gas prices. It is important to analyze whether these other sectors constitute a better use for natural gas than electricity generation, which has alternative fuels at its disposal.

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UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 9

Jamarillo, et al., *Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation* (Oct. 12, 2005)

January 27, 2012