



Chapter 6

Potential Environmental Impacts

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Chapter 6 – Potential Environmental Impacts

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Chapter 6 POTENTIAL ENVIRONMENTAL IMPACTS

This revised Draft SGEIS incorporates by reference the 1992 Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program - including the draft volumes released in 1988, the final volume released in 1992 - and the 1992 Findings Statement. Therefore, the text in this Supplement is not exhaustive with respect to potential environmental impacts, but instead focuses on new, different or additional information relating to potential impacts of horizontal drilling and high-volume hydraulic fracturing.

6.1 Water Resources

Protection of water resources is a primary emphasis of the Department. Water resource matters that may be impacted by activities associated with high-volume hydraulic fracturing are identified and discussed in Chapter 2.

Adverse impacts to water resources might reasonably be anticipated in the context of unmitigated high-volume hydraulic fracturing due to: 1) water withdrawals affecting surface or groundwater, including wetlands; 2) polluted stormwater runoff; 3) surface chemical or petroleum spills; 4) pit or surface impoundment failures or leaks; 5) groundwater contamination associated with improper well drilling and construction; and 6) improper waste disposal. NYC's subsurface water supply infrastructure that is located in areas outside the boundary of the NYC Watershed could also be impacted by unmitigated high-volume hydraulic fracturing. Potential surface water impacts discussed herein are applicable to all areas that might be developed for natural gas resources through high-volume hydraulic fracturing.

Three water resources issues were the subject of extensive comment during the public scoping process:

- 1) Potential degradation of NYC's surface drinking water supply;
- 2) Potential groundwater contamination from the hydraulic fracturing procedure itself; and
- 3) Adverse impacts to the Upper Delaware Scenic and Recreational River.

Geological factors as well as standard permit requirements that the Department proposes to impose that would limit or avoid the potential for groundwater contamination from high-volume hydraulic fracturing are discussed in Chapters 5, 7 and 8.

6.1.1 Water Withdrawals

Water for hydraulic fracturing may be obtained by withdrawing it from surface water bodies or new or existing water-supply wells drilled into aquifers. Without proper controls on the rate, timing and location of such withdrawals, modifications to groundwater levels, surface water levels, and stream flow could result in adverse impacts to aquatic ecosystems, downstream flow levels, drinking water assured yields, wetlands, and aquifer recharge. While surface-water bodies are still the primary source of water supplies for the drilling of Marcellus wells in Pennsylvania, municipal and public water-supply wells have been used there as well.

6.1.1.1 Reduced Stream Flow

Potential effects of reduced stream flow caused by withdrawals could include:

- insufficient supplies for downstream uses such as public water supply;
- adverse impacts to quantity and quality of aquatic, wetland, and terrestrial habitats and the biota that they support; and
- exacerbation of drought effects.

Unmitigated withdrawals could adversely impact fish and wildlife health due to exposure to unsuitable water temperature and dissolved oxygen concentrations, particularly in low-flow or drought conditions. It could also affect downstream dischargers whose effluent limits are linked to the stream's flow rate. Water quality could be degraded and adverse impacts on natural aquatic habitat increased if existing pollutants from point sources (e.g., discharge pipes) and/or non-point sources (e.g., runoff from farms and paved surfaces) become concentrated.

6.1.1.2 Degradation of a Stream's Best Use

New York State water use classifications are provided in Section 2.4.1. All of the uses are dependent upon sufficient water in the stream to support the specified use. As noted, uncontrolled withdrawals of water from streams in connection with high-volume hydraulic

fracturing has the potential to adversely impact stream water supply and thus stream water use classifications.

6.1.1.3 Impacts to Aquatic Habitat

Habitat for stream organisms is provided by the shape of the stream channel and the water that flows through it. It is important to recognize that the physical habitat (e.g., pools, riffles, in-stream cover, runs, glides, bank cover, etc.) essential for maintaining the aquatic ecosystem is formed by periodic disturbances that exist in the natural hydrograph; the seasonal variability in stream flow resulting from annual precipitation and associated runoff. Maintaining this habitat diversity within a stream channel is essential in providing suitable conditions for all the life stage of the aquatic organisms. Stream fish distribution, community structure, and population dynamics are related to channel morphology. Streamflow alterations that modify channel morphology and habitat would result in changes in aquatic populations and community shifts that alter natural ecosystems. Creating and maintaining high quality habitat is a function of seasonally high flows because scour of fines from pools and deposition of bedload in riffles is most predominant at high flow associated with spring snowmelt or high rain runoff. Periodic resetting of the aquatic system is an essential process for maintaining stream habitat that would continuously provide suitable habitat for all aquatic biota. Clearly, alteration of flow regimes, sediment loads and riparian vegetation would cause changes in the morphology of stream channels. Any streamflow management decision would not impair flows necessary to maintain the dynamic nature of a river channel that is in a constant state of change as substrates are scoured, moved downstream and re-deposited.

6.1.1.4 Impacts to Aquatic Ecosystems

Aquatic ecosystems could be adversely impacted by:

- changes to water quality or quantity;
- insufficient stream flow for aquatic biota stream habitat; or
- the actual water withdrawal infrastructure.

Native aquatic species possess life history traits that enable individuals to survive and reproduce within a certain range of environmental variation. Flow depth and velocity, water temperature,

substrate size distribution and oxygen content are among the myriad of environmental attributes known to shape the habitat that control aquatic and riparian species distributions. Streamflow alterations can impact aquatic ecosystems due to community shifts made in response to the corresponding shifts in these environmental attributes. The perpetuation of native aquatic biodiversity and ecosystem integrity depends on maintaining some semblance of natural flow patterns that minimize aquatic community shifts. The natural flow paradigm states that the full range of natural intra- and inter-annual variation of hydrologic regimes, and associated characteristics of timing, duration, frequency and rate of change, are critical in sustaining the full native biodiversity and integrity of aquatic ecosystems.

Improperly installed water withdrawal structures can result in the entrainment of aquatic organisms, which can remove any/all life stages of fish and macroinvertebrates from their natural habitats as they are withdrawn with water. While most of the water bodies supplying water for high-volume hydraulic fracturing contain species of fish whose early life stages are not likely to be entrained because of their life history and behavioral characteristics, fish in their older life stages could be entrained without measures to avoid or reduce adverse impacts. To avoid adverse impacts to aquatic biota from entrainment, intake pipes can be screened to prevent entry into the pipe. Additionally, the loss of biota that becomes trapped on intake screens, referred to as impingement, can be minimized by properly sizing the intake to reduce the flow velocity through the screens. Depending on the water body from which water is being withdrawn, the location of the withdrawal structure on the water body and the site-specific aquatic organisms requiring protection, project-specific technologies may be required to minimize the entrainment and impingement of aquatic organisms. Technologies and operational measures that are proven effective in reducing these impacts include but are not limited to narrow-slot width wedge-wire screens (0.5 mm-2.0 mm), fine mesh screening, low intake velocities (0.5 feet per second (fps) or less), and seasonal restrictions on intake operation. Transporting water from the water withdrawal location for use off-site, as discussed in Section 6.4.2.2, can transfer invasive species from one water body to another via trucks, hoses, pipelines, and other equipment. Screening of the intakes can minimize this transfer; however, additional site-specific mitigation considerations may be necessary.

6.1.1.5 Impacts to Wetlands

The existence and sustainability of wetland habitats directly depend on the presence of water at or near the surface of the soil. The functioning of a wetland is driven by the inflow and outflow of surface water and/or groundwater. As a result, withdrawal of surface water or groundwater for high-volume hydraulic fracturing could impact wetland resources. These potential impacts depend on the amount of water within the wetland, the amount of water withdrawn from the catchment area of the wetland, and the dynamics of water flowing into and out of the wetland. Even small changes in the hydrology of the wetland can have significant impacts on the wetland plant community and on the animals that depend on the wetland. It is important to preserve the hydrologic conditions and to understand the surface water and groundwater interaction to protect wetland areas.

6.1.1.6 Aquifer Depletion

The primary concern regarding groundwater withdrawal is aquifer depletion that could affect other uses, including nearby public and private water supply wells. This includes cumulative impacts from numerous groundwater withdrawals and potential aquifer depletion from the incremental increase in withdrawals if groundwater supplies are used for hydraulic fracturing. Aquifer depletion may also result in aquifer compaction which can result in localized ground subsidence. Aquifer depletion can occur in both confined and unconfined aquifers.

The depletion of an aquifer and a corresponding decline in the groundwater level can occur when a well, or wells in an aquifer are pumped at a rate in excess of the recharge rate to the aquifer. Essentially, surface water and groundwater are one continuous resource; therefore, it also is possible that aquifer depletion can occur if an excessive volume of water is removed from a surface water body that recharges an aquifer. Such an action would result in a reduction of recharge which could potentially deplete an aquifer. This “influents” condition of surface water recharging groundwater occurs mainly in arid and semi-arid climates, and is not common in New York, except under conditions such as induced infiltration of surface water by aquifer withdrawal (e.g., pumping of water wells).¹

¹ Alpha, 2009, p. 3-19, with updates from DEC.

Aquifer depletion can lead to reduced discharge of groundwater to streams and lakes, reduced water availability in wetland areas, and corresponding impacts to aquatic organisms that depend on these habitats. Flowing rivers and streams are merely a surface manifestation of what is flowing through the shallow soils and rocks. Groundwater wells impact surface water flows by intercepting groundwater that otherwise would enter a stream. In fact, many New York headwater streams rely entirely on groundwater to provide flows in the hot summer months. It is therefore important to understand the hydrologic relationship between surface water, groundwater, and wetlands within a watershed to appropriately manage rates and quantities of water withdrawal.²

Depletion of both groundwater and surface water can occur when significant water withdrawals are transported out of the basin from which they originated. These transfers break the natural hydrologic cycle, since the transported water never makes it downstream nor returns to the original watershed to help recharge the aquifer. Without the natural flow regime, including seasonal high flows, stream channel and riparian habitats critical for maintaining the aquatic biota of the stream may be adversely impacted.

6.1.1.7 Cumulative Water Withdrawal Impacts³

As noted in later in this chapter, it is estimated that within 30 years there could be up to 40,000 wells developed with the high-volume hydraulic fracturing technology. This could result in substantial water usage in the study area. There are several potential types of impacts, when considered cumulatively, that could result from these estimated new withdrawals associated with natural gas development. Those are:

- Stream flow, surface water and groundwater depletion;
- Loss of aquifer storage capacity due to compaction;
- Water quality degradation;
- Wetland hydrology and habitat;

² Alpha, 2009, p. 81.

³ Alpha, 2009 pp. 3-28.

- Fish and aquatic organism impacts;
- Significant habitats, endangered, rare or threatened species impacts; and
- Existing water users and reliability of their supplies.

Evaluation of the overall impact of multiple water withdrawals based on the projection of maximum activity consider the existing water usage, the non-continuous nature of withdrawals for natural gas development, and the natural replenishment of water resources. Natural replenishment is described in Section 2.4.8.

The DRBC and SRBC have developed regulations, policies, and procedures to characterize existing water use and track approved withdrawals. Changes to these systems also require Commission review. Review of the requirements of the DRBC and SRBC indicates that the operators and the reviewing authority would perform evaluations to assess the potential impacts of water withdrawal for well drilling, and consider the following issues and information.

- Comprehensive project description that includes a description of the proposed water withdrawal (location, volume, and rate) and its intended use;
- Existing water use in the withdrawal area;
- Potential impacts, both ecological and to existing users, from the new withdrawal;
- Availability of water resources (surface water and/or groundwater) to support the proposed withdrawals;
- Availability of other water sources (e.g., treated waste water) and conservation plans to meet some or all of the water demand;
- Contingencies for low flow conditions that include passby flow criteria;
- Public notification requirements;
- Monitoring and reporting;
- Inspections;
- Mitigation measures;
- Supplemental investigations, including but not limited to, aquatic surveys;

- Potential impact to significant habitat and endangered rare or threatened species; and
- Protection of subsurface infrastructure.

Existing Regulatory Scheme for Water Usage and Withdrawals

The DRBC and SRBC use a permit system and approval process to regulate existing water usage in their respective basins. The DRBC and SRBC require applications in which operators provide a comprehensive project description that includes the description of the proposed withdrawals.

The project information required includes site location, water source(s), withdrawal location(s), proposed timing and rate of water withdrawal and the anticipated project duration. The operators identify the amount of consumptive use (water not returned to the basin) and any import or export of water to or from the basin. The method of conveyance from the point(s) of withdrawal to the point(s) of use is also defined.

There are monitoring and reporting requirements once the withdrawal and consumptive use for a project has been approved. These requirements include metering withdrawals and consumptive use, and submitting quarterly reports to the Commission. Monitoring requirements can include stream flow and stage measurements for surface water withdrawals and monitoring groundwater levels for groundwater withdrawals.

The recently enacted Water Resources Law extends the Department's authority to regulate all water withdrawals over 100,000 gpd throughout all of New York State. This law applies to all such withdrawals where water would be used for high-volume hydraulic fracturing. Withdrawal permits issued in the future by the Department, pursuant to the regulations implementing this law, would include conditions to allow the Department to monitor and enforce water quality and quantity standards, and requirements. The Department is beginning the process for enacting regulations on this new law. These standards and requirements may include: passby flow; fish impingement and entrainment protections; protections for aquatic life; reasonable use; water conservation practices; and evaluation of cumulative impacts on other water withdrawals. The Department intends to seek consistency in water resource management within New York between the DRBC, SRBC and the Department.

Surface water and groundwater are withdrawn daily for a wide range of uses. New York ranks as one of the top states with respect to the total amount of water withdrawals. Figure 6.1 presents a graph indicating the total water withdrawal for New York is approximately 9 to 10 billion gpd, based on data from 2000. Figure 6.2 presents fresh water use in New York, including the projected peak water use for high-volume hydraulic fracturing.

The DRBC reports on the withdrawal of water for various purposes. The daily water withdrawals, exports, and consumptive uses in the Delaware River Basin are shown in Figure 6.3. The total water withdrawal from the Delaware River Basin was 8,736 MGD, based on 2003 water use records. The highest water use was for thermoelectric power generation at 5,682 million gpd (65%), followed by 875 million gpd (10%) for public water supply, 650 million gpd (7.4%) for the NYC public water supply, 617 million gpd (7%) for hydroelectric, and 501 million gpd (5.7%) for industrial purposes. The amount of water used for mining is 70 million gpd (0.8%). The “mining” category typically includes withdrawals for oil and gas drilling; however, DRBC has not yet approved water withdrawal for Marcellus Shale drilling operations. The information in Figure 6.3 shows that 4.3% (14 million gpd) of the water withdrawn for consumptive use is for mining and 88% (650 million gpd) of water exported from the Delaware River Basin is diverted to NYC.

Whereas certain withdrawals, like many public water supplies are returned to the basin’s hydrologic cycle, out-of-basin transfers, like the NYC water-supply diversion, some evaporative losses, and withdrawals for hydraulic fracturing, are considered as 100% consumptive losses because this water is essentially lost to the basin’s hydrologic cycle.

Withdrawals for High-Volume Hydraulic Fracturing

Current water withdrawal volumes when compared to withdrawal volumes associated with current natural gas drilling indicates that the historical percentage of withdrawn water that goes to natural gas drilling is very low. The amount of water withdrawn specifically for high-volume hydraulic fracturing also is projected to be relatively low when compared to existing overall levels of water use. The total volume of water withdrawn for high-volume hydraulic fracturing in New York would not be known with precision until applications are received, reviewed, and potentially approved or rejected by the appropriate regulatory agency or agencies, but can be

estimated based on activity in Pennsylvania and projections of potential levels of well drilling activity in New York.

Between July 2008 and February 2011, average water usage for high-volume hydraulic fracturing within the Susquehanna River Basin in Pennsylvania was 4.2 million gallons per well, based on data for 553 wells.⁴ Current practice is to use 80% - 90% fresh water and 10% - 20% recycled flowback water for high-volume hydraulic fracturing.⁵ Average fresh water use as 85% of the total used per well is consistent with statistics reported by the SRBC.⁶ This would equate to average fresh water use of 3.6 million gallons per well (85% of 4.2 million gallons). Industry projects a potential peak annual drilling rate in New York of 2,462 wells, a level of drilling that is projected to be at the very high end of activity. Although some of these wells may be vertical wells which require less water than horizontal wells where high-volume hydraulic fracturing is planned, all of the wells reflected in the peak drilling rate will be conservatively considered to be horizontal wells for the purpose of this analysis. Multiplying the peak projected annual wells by current average use per well results in calculated peak *annual* fresh water usage for high-volume hydraulic fracturing of 9 billion gallons. Total *daily* fresh water withdrawal in New York has been estimated at approximately 10.3 billion gallons.⁷ 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%. The potential relationship between water use for high-volume hydraulic fracturing and other purposes is shown in Figure 6.2.

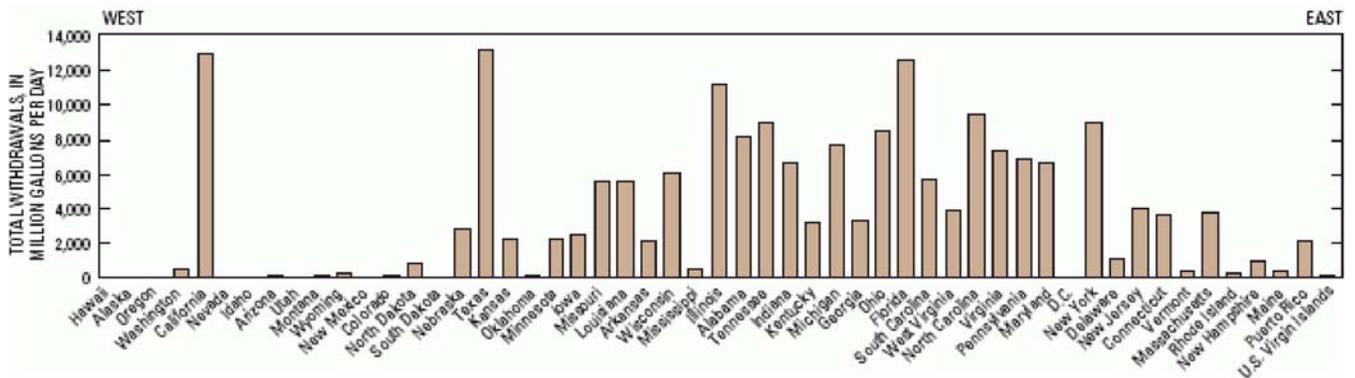
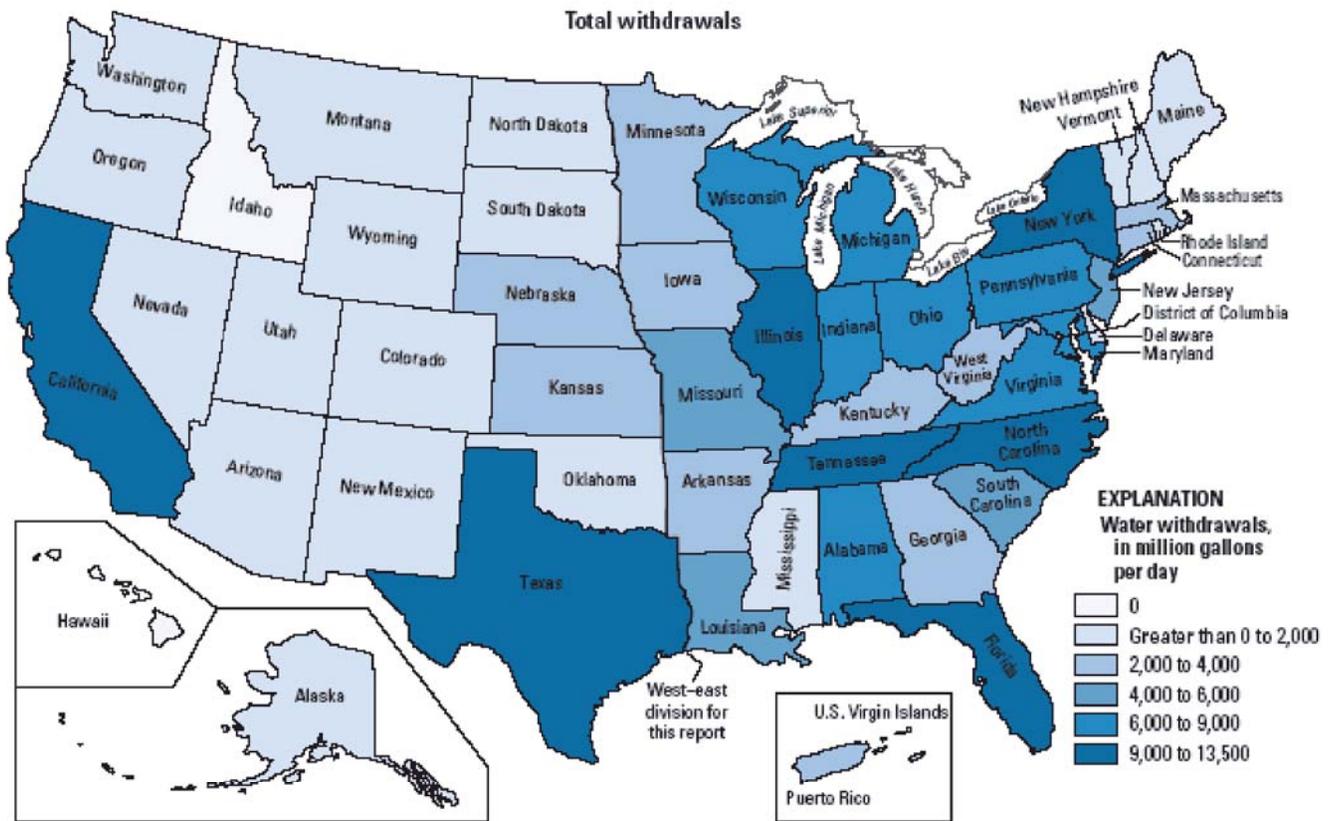
While projected water withdrawals and consumptive use of water are modest relative to overall water withdrawals in New York, there remains the potential for adverse impacts particularly when withdrawals take place during low-flow or drought conditions. Adverse impacts previously discussed may also occur when high or unsustainable withdrawals take place in localized ground or surface water that lack adequate hydrologic capacity.

⁴ SRBC 2011.

⁵ ALL Consulting, 2010, p. 74.

⁶ Richenderfer, 2010, p. 30.

⁷ Kenny et al, 2005, p.7.



Source: USGS

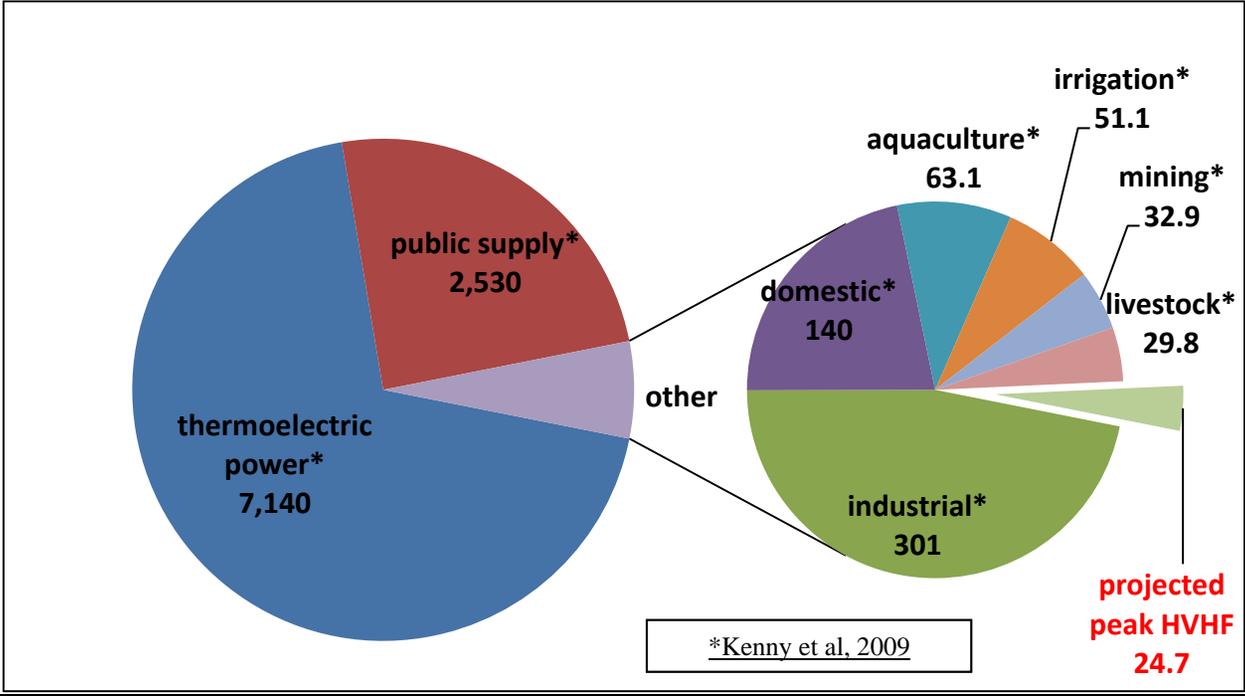


FIGURE 6.1

WATER WITHDRAWALS IN THE UNITED STATES

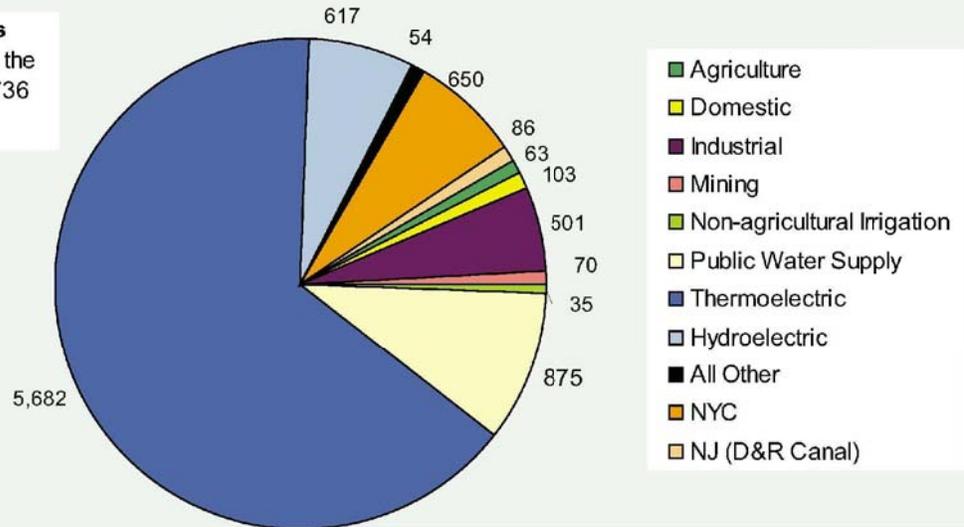
Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

Figure 6.2 - Fresh Water Use in NY (millions of gallons per day) with Projected Peak Water Use for High-Volume Hydraulic Fracturing (New July 2011)⁸

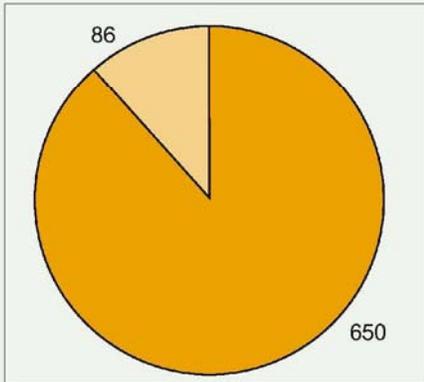


⁸ This figure is a replacement for Figure 6.2 in the 2009 draft SGEIS which was a bar graph prepared by SRBC showing projected water use in the Susquehanna River Basin.

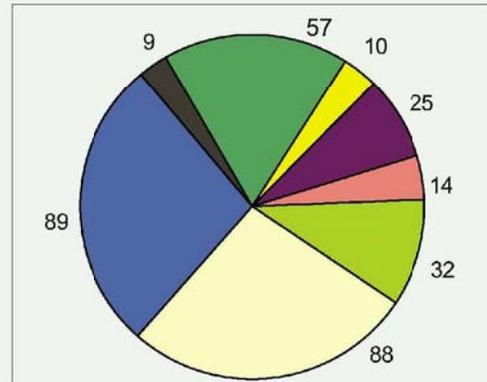
Total Water Withdrawals
(ground and surface) from the Delaware River Basin: 8,736 mgd



Major Exports from the Delaware River Basin: 736 mgd



Consumptive Use in the the Delaware River Basin: 324 mgd



Pie chart values in mgd
(million gallons per day)

Source: DRBC



FIGURE 6.3

**DAILY WATER WITHDRAWALS,
EXPORTS, AND CONSUMPTIVE USES
IN THE DELAWARE RIVER BASIN**

Technical Support Document to the
Draft Supplemental Generic
Environmental Impact Statement

6.1.2 Stormwater Runoff

Stormwater, whether as a result of rainfall or snowmelt, is a valuable resource. It is the source of water for lakes and streams, as well as aquifers. However, stormwater runoff, particularly when it interacts with the human environment, is a pathway for contaminants to be conveyed from the land surface to streams and lakes and groundwater. This is especially true for stormwater runoff from asphalt, concrete, gravel/dirt roads, other impervious surfaces, outdoor industrial activity, and earthen construction sites, where any material collected on the ground is washed into a nearby surface water body. Stormwater runoff may also contribute to heightened peak flows and flooding.

On an undisturbed landscape, precipitation is held by vegetation and pervious soil, allowing it to slowly filter into the ground. This benefits water resources by using natural filtering properties, replenishing groundwater aquifers and feeding lakes and streams through base flow during dry periods. On a disturbed or developed landscape, it is common for the ground surface to be compacted or otherwise made less pervious and for runoff to be shunted away quickly with greater force and significantly higher volumes. Such hydrological modifications result in less groundwater recharge and more rapid runoff to streams, which may cause increased stream erosion and result in water quality degradation, habitat loss and flooding.

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.

Excess sediment can fill or bury the rock cobble of streams that serve as spawning habitat for fish and the macro-invertebrate insects that serve as their food source. Stormwater runoff and heightened sediment loads carry excess levels of nutrient phosphorus and nitrogen that is a major cause of algae bloom, low dissolved oxygen and other water-quality impairments.

Initial land clearing exposes soil to erosion and more rapid runoff. Construction equipment is a potential source of contamination from such things as hydraulic, fuel and lubricating fluids. Equipment and any materials that are spilled, including additive chemicals and fuel, are exposed

to rainfall, so that contaminants may be conveyed off-site during rain events if they are not properly contained. 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 pit is proposed.

A production site, including access roads, is also a potential source of stormwater runoff impacts discussed above because its hydrologic characteristics, sediment, nutrient, contaminant, and water volumes may be substantially different from the pre-developed condition.

6.1.3 Surface Spills and Releases at the Well Pad

Spills or releases can occur as a result of tank ruptures, pipng failures, equipment or surface impoundment failures, overfills, vandalism, accidents (including vehicle collisions), ground fires, drilling and production equipment defects, or improper operations. Spilled, leaked or released fluids could flow to a surface water body or infiltrate the ground, reaching subsurface soils and aquifers.

To evaluate potential health impacts from spills or releases of additives, fracturing fluid containing diluted additives or residual diluted additive chemicals in flowback water, the NYSDOH reviewed the composition of additives proposed for high-volume hydraulic fracturing in New York. The NYSDOH concluded that the proposed additives contain similar types of chemical constituents as the products that have been used for many years for hydraulic fracturing of traditional vertical wells in NYS. Some of the same products are used in both well types. The total amount of fracturing additives and water used in hydraulic fracturing of horizontal wells is considerably larger than for traditional vertical wells. This suggests the potential environmental consequences of an upset condition could be proportionally larger for horizontal well drilling and fracturing operations. As mentioned earlier, the 1992 GEIS addressed hydraulic fracturing in Chapter 9, and NYSDOH's review did not identify any potential exposure situations associated with horizontal drilling and high-volume hydraulic fracturing that are qualitatively different from those addressed in the 1992 GEIS.

6.1.3.1 Drilling

Contamination of surface water bodies and groundwater resources during well drilling could occur as a result of failure to maintain stormwater controls, ineffective site management and inadequate surface and subsurface fluid containment practices, poor casing construction, or accidental spills and releases including well blow-outs during drilling or well component failures during completion operations. A release could also occur during a blow-out event if there are not trained personnel on site that are educated in the proper use of the BOP system. Surface spills would involve materials and fluids present at the site during the drilling phase. 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 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.

6.1.3.2 Hydraulic Fracturing Additives

As with the drilling phase, contamination of surface water bodies and groundwater resources during well stimulation could occur as a result of failure to maintain stormwater controls, ineffective site management and surface and subsurface fluid containment practices, poor well construction and grouting, or accidental spills and releases including failure of wellhead components during hydraulic fracturing. These issues are discussed in Chapters 8 and 9 of the 1992 GEIS, but are acknowledged here because of the larger volumes of fluids and materials to be managed for high-volume hydraulic fracturing. The potential contaminants are listed in Table 5.7 and grouped into categories recommended by NYSDOH in Table 5.8. URS compared the list of additive chemicals to the parameters regulated via federal and state primary or secondary drinking water standards, SPDES discharge limits (see Section 7.1.8), and DOW Technical and Operational Guidance Series 1.1.1 (TOGS111), Ambient Water Quality Standards and Guidance

Values and Groundwater Effluent Limitations.^{9,10} In NYS, the state drinking water standards (10 NYCRR 5) apply to all public water supplies and set maximum contaminant levels (MCLs) for essentially all organic chemicals in public drinking water. See Table 6.1.

6.1.3.3 Flowback Water and Production Brine

Gelling agents, surfactants and chlorides are identified in the 1992 GEIS as the flowback water components of greatest environmental concern.¹¹ Other flowback components can include other dissolved solids, metals, biocides, lubricants, organics and radionuclides. Opportunities for spills, leaks, and operational errors during the flowback water recovery stage are the same as they are during the prior stages with additional potential releases from:

- hoses or pipes used to convey flowback water to tanks or a tanker truck for transportation to a treatment or disposal site; and
- tank leakage.

In general, flowback water is water and associated chemical constituents returning from the borehole during or proximate in time to hydraulic fracturing activities. Production brine, on the other hand, is fluid that returns from the borehole after completion of drilling operations while natural gas production is underway. The chemical characteristics and volumes of flowback water and production brine are expected to differ in significant respects.

Flowback water composition based on a limited number of out-of-state samples from Marcellus wells is presented in Table 5.9. A comparison of detected flowback parameters, except radionuclides, to regulated parameters is presented in Table 6.1.¹²

Table 5.10 lists parameters found in the flowback analyses, except radionuclides, that are regulated in New York. The number of samples that were analyzed for the particular parameter is shown in Column 3, and the number of samples in which parameters were detected is shown in Column 4. The minimum, median and maximum concentrations detected are indicated in

⁹ URS, 2009, p. 4-18, et seq.

¹⁰ <http://www.dec.ny.gov/regulations/2652.html>.

¹¹ NYSDEC, 1992, GEIS, p. 9-37.

¹² URS, 2009, p. 4-18, et seq.

Columns 5, 6 and 7.¹³ Radionuclides data is presented in Chapter 5, and potential impacts and regulation are discussed in Section 6.8.

Table 5.11 lists parameters found in the flowback analyses that are not regulated in New York. Column 2 shows the number of samples that were analyzed for the particular parameter; column 3 indicates the number of samples in which the parameter was detected.¹⁴

Information presented in Tables 5.10 and 5.11 are based on limited data from Pennsylvania and West Virginia. Samples were not collected specifically for this type of analysis or under the Department's oversight. Characteristics of flowback from the Marcellus Shale in New York are expected to be similar to flowback from Pennsylvania and West Virginia, but not identical. The raw data for these tables came from several sources, with likely varying degrees of reliability, and the analytical methods used were not all the same for given parameters. Sometimes, laboratories need to use different analytical methods depending on the consistency and quality of the sample; sometimes the laboratories are only required to provide a certain level of accuracy. Therefore, the method detection limits may be different. The quality and composition of flowback from a single well can also change within a few days after the well is fractured. This data does not control for any of these variables.¹⁵

¹³ URS, 2009, pp. 4-10, 4-31 et seq.

¹⁴ URS, 2009, pp. 4-10, p. 4-35.

¹⁵ URS, 2009, p. 4-31.

Table 6.1 - Comparison of additives used or proposed for use in NY, parameters detected in analytical results of flowback from the Marcellus operations in PA and WV and parameters regulated via primary and secondary drinking water standards, SPDES or TOGS111 (Revised August 2011)^{16, 17}

CAS Number	Parameter Name	Used in Additives ^{18,19}	Found in Flowback ²⁰	USEPA MCL or TT (mg/L) ^{21,22}	SPDES Tables ²³	TOGS111 Tables	NYS MCL, (mg/L) ²⁴
106-24-1	(2E)-3,7-dimethylocta-2,6-dien-1-ol	Yes					0.05
67701-10-4	(C8-C18) And (C18) Unsaturated Alkylcarboxylic Acid Sodium Salt	Yes					\$\$

¹⁶ Table 6.1 was compiled by URS Corporation, 2011 and revised by the Department in coordination with NYSDOH.

¹⁷ This table includes parameters detected in the MSC Study.

¹⁸ Information in the “Used in Additives” column is based on the composition of additives used or proposed for use in New York.

¹⁹ Parameters marked with ¥ indicates that the compound dissociates, and its components are separately regulated. Not all dissociating compounds are marked.

²⁰ Information in the “Found in Flowback” column is based on analytical results of flowback from operations in Pennsylvania or West Virginia. There are/may be products used in fracturing operations in Pennsylvania that have not yet been proposed for use in New York for which, therefore, the Department does not have chemical composition data. Blank entries in the “Found in Flowback” column indicate that the parameter was either not sampled for or not detected in the flowback.

²¹ USEPA Maximum Contaminant Level (MCL) - The highest level of a contaminant that is allowed in drinking water. MCLs are set as close to MCLGs as feasible using the best available treatment technology and taking cost into consideration. MCLs are enforceable standards. From USEPA Title 40, Part 141--National Primary Drinking Water Regulations.

²² USEPA Treatment Technique (TT) – A required process intended to reduce the level of a contaminant in drinking water. From USEPA Title 40, Part 141 – National Primary Drinking Water Regulations.

²³ SPDES or TOGS typically regulates or provides guidance for the total substance, (e.g., iron) and rarely regulates or provides guidance for only its dissolved portion (e.g., dissolved iron). The dissolved component is implicitly covered in the total substance. Therefore, the dissolved component is not included in this table. Flowback analyses provided information for the total and dissolved components of metals. Understanding the dissolved vs. suspended portions of a substance is valuable when determining potential treatment techniques.

²⁴ 10 NYCRR Part 5-1.50 through 5-1.52. Under 10 NYCRR Part 5, organic contaminants (with very few exceptions) have either a Specific MCL (28 compounds plus 1 chemical mixture) or a General MCL of 0.05 mg/L for Unspecified Organic Contaminants (UOC) or 0.005 mg/L for Principal Organic Contaminants (POC). A total UOC + POC MCL of 0.1 mg/L also applies to all organic contaminants in drinking water. 10 NYCRR Part 5 also contains 23 MCLs for inorganic contaminants. A section sign (\$) indicates that, for organic salts, the free compound (the expected form in drinking water) would be a UOC, but that salts themselves would not be UOC. A double section sign (§§) indicates that, for parameters listed as a group or mixture of related chemicals (e.g., Ethoxylated alcohol (C14-15), petroleum distillates, essential oils) a state MCL does not apply to the group as a whole, but would apply to each individual component of the group if detected in drinking water. A triple section sign (§§§) indicates that, for parameters listed as a polymer, the UOC MCL would apply to the polymer itself, but either the UOC or POC MCL would apply to the individual monomer components. An asterisk (*) indicates that the total trihalomethane (THM) MCL of 0.08 mg/L also applies.

CAS Number	Parameter Name	Used in Additives ^{18,19}	Found in Flowback ²⁰	USEPA MCL or TT (mg/L) ^{21,22}	SPDES Tables ²³	TOGS111 Tables	NYS MCL, (mg/L) ²⁴
02634-33-5	1,2-Benzisothiazolin-2-one / 1,2-benzisothiazolin-3-one	Yes					0.05
00087-61-6	1,2,3-Trichlorobenzene		Yes		Table 9	Tables 1,5	0.005
00095-63-6	1,2,4-Trimethylbenzene	Yes	Yes		Table 9	Tables 1,5	0.005
93858-78-7	1,2,4-Butanetricarboxylic acid, 2-phosphono-, potassium salt	Yes					0.05
00108-67-8	1,3,5-Trimethylbenzene		Yes		Tables 9,10	Tables 1,5	0.005
00123-91-1	1,4-Dioxane	Yes			Table 8		0.05
03452-07-1	1-icosene	Yes					0.05
00629-73-2	1-hexadecene	Yes					0.05
104-46-1	1-Methoxy-4-propenylbenzene	Yes					0.05
124-28-7	1-Octadecanamine, N, N-dimethyl- / N,N-Timethyloctadecylamine	Yes					0.05
112-03-8	1-Octadecanaminium, N,N,N-Trimethyl-, Chloride / Trimethyloctadecylammonium chloride	Yes					0.05
00112-88-9	1-octadecene	Yes					0.05
40623-73-2	1-Propanesulfonic acid	Yes					0.05
01120-36-1	1-tetradecene	Yes					0.05
98-55-5	2-(4-methyl-1-cyclohex-3-enyl)propan-2-ol	Yes					0.05
10222-01-2	2,2-Dibromo-3-nitrilopropionamide	Yes			Table 9	Tables 1,5	
27776-21-2	2,2'-azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride	Yes					0.05
73003-80-2	2,2-Dibromomalonamide	Yes					0.05
00105-67-9	2,4-Dimethylphenol		Yes		Table 6	Tables 1,5	0.05
00087-65-0	2,6-Dichlorophenol		Yes		Table 8		0.005
15214-89-8	2-Acrylamido-2-methylpropanesulphonic acid sodium salt polymer	Yes					0.05
46830-22-2	2-acryloyloxyethyl(benzyl)dimethylammonium chloride	Yes					0.05
00052-51-7	2-Bromo-2-nitro-1,3-propanediol	Yes			Table 10		
00111-76-2	2-Butoxy ethanol / Ethylene glycol monobutyl ether / Butyl Cellusolve	Yes					0.05
01113-55-9	2-Dibromo-3-Nitrilopropionamide / 2-Monobromo-3-nitrilopropionamide	Yes					0.05
00104-76-7	2-Ethyl Hexanol	Yes					0.05
00091-57-6	2-Methylnaphthalene		Yes		Table 8	Tables 1,3	0.05

CAS Number	Parameter Name	Used in Additives ^{18,19}	Found in Flowback ²⁰	USEPA MCL or TT (mg/L) ^{21,22}	SPDES Tables ²³	TOGS111 Tables	NYS MCL, (mg/L) ²⁴
00095-48-7	2-Methylphenol		Yes		Table 8		0.05
109-06-8	2-Picoline (2-methyl pyridine)		Yes		Table 8	Table 3	0.05
00067-63-0	2-Propanol / Isopropyl Alcohol / Isopropanol / Propan-2-ol	Yes	Yes		Table 10		0.05
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-chloride, homopolymer	Yes					0.05
95077-68-2	2-Propenoic acid, homopolymer sodium salt	Yes					0.05
09003-03-6	2-propenoic acid, homopolymer, ammonium salt	Yes					0.05
25987-30-8	2-Propenoic acid, polymer with 2 p-propenamides, sodium salt / Copolymer of acrylamide and sodium acrylate	Yes					0.05
71050-62-9	2-Propenoic acid, polymer with sodium phosphinate (1:1)	Yes					0.05
66019-18-9	2-propenoic acid, telomer with sodium hydrogen sulfite	Yes					0.05
00107-19-7	2-Propyn-1-ol / Propargyl Alcohol	Yes					0.05
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.1 ^{3,7}]decane, 1-(3-chloro-2-propenyl)-chloride,	Yes					0.05
106-22-9	3,7 - dimethyl-6-octen-1-ol	Yes					0.05
5392-40-5	3,7-dimethyl-2,6-octadienal	Yes					0.005
00115-19-5	3-methyl-1-butyn-3-ol	Yes					0.05
00108-39-4	3-Methylphenol		Yes		Table 8		0.05
104-55-2	3-phenyl-2-propenal	Yes					0.005
127-41-3	4-(2,6,6-trimethyl-1-cyclohex-2-enyl)-3-buten-2-one	Yes					0.05
00072-55-9	4,4 DDE		Yes		Table 6	Tables 1,5	0.005
121-33-5	4-hydroxy-3-methoxybenzaldehyde	Yes					0.05
00106-44-5	4-Methylphenol		Yes		Table 8		0.05
127087-87-0	4-Nonylphenol Polyethylene Glycol Ether Branched / Nonylphenol ethoxylated / Oxyalkylated Phenol	Yes					0.05
00057-97-6	7,12-Dimethylbenz(a)anthracene		Yes		Table 8	Table 3	0.05
00064-19-7	Acetic acid	Yes	Yes		Table 10		0.05
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine	Yes					0.05
00108-24-7	Acetic Anhydride	Yes			Table 10		0.05

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00067-64-1	Acetone	Yes	Yes		Table 7	Tables 1,5	0.05
00098-86-2	Acetophenone		Yes			Table 3	0.05
00079-06-1	Acrylamide	Yes		TT	Table 9	Tables 1,5	0.005
38193-60-1	Acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer	Yes					0.05
25085-02-3	Acrylamide - Sodium Acrylate Copolymer or Anionic Polyacrylamide	Yes					0.05
69418-26-4	Acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride	Yes					0.05
15085-02-3	Acrylamide-sodium acrylate copolymer	Yes					0.05
00107-13-1	Acrylonitrile		Yes		Table 6	Tables 1,5	
68891-29-2	Alcohols C8-10, ethoxylated, monoether with sulfuric acid, ammonium salt	Yes					§,§§
68526-86-3	Alcohols, C11-14-iso-, C13-rich	Yes					§§
68551-12-2	Alcohols, C12-C16, Ethoxylated (a.k.a. Ethoxylated alcohol)	Yes					§§
00309-00-2	Aldrin		Yes			Tables 1,5	
	Aliphatic acids	Yes					§§
	Aliphatic alcohol glycol ether	Yes					0.05
64742-47-8	Aliphatic Hydrocarbon / Hydrotreated light distillate / Petroleum Distillates / Isoparaffinic Solvent / Paraffin Solvent / Napthenic Solvent	Yes					§§
	Alkalinity, Carbonate, as CaCO ₃		Yes		Table 10		
64743-02-8	Alkenes	Yes					§§
68439-57-6	Alkyl (C14-C16) olefin sulfonate, sodium salt	Yes					0.05
	Alkyl Aryl Polyethoxy Ethanol	Yes					0.05
	Alkylaryl Sulfonate	Yes					0.05
09016-45-9	Alkylphenol ethoxylate surfactants	Yes					§§
07439-90-5	Aluminum		Yes		Table 7	Tables 1,5	
01327-41-9	Aluminum chloride	Yes (¥)					
68155-07-7	Amides, C8-18 and C19-Unsatd., N,N-Bis(hydroxyethyl)	Yes					§§
73138-27-9	Amines, C12-14-tert-alkyl, ethoxylated	Yes					§§§
71011-04-6	Amines, Ditalow alkyl, ethoxylated	Yes					§§§
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates	Yes					§§§

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01336-21-6	Ammonia	Yes			Yes		
00631-61-8	Ammonium acetate	Yes			Table 10		§
68037-05-8	Ammonium Alcohol Ether Sulfate	Yes (¥)					0.05
07783-20-2	Ammonium bisulfate	Yes (¥)					
10192-30-0	Ammonium Bisulphite	Yes (¥)					
12125-02-9	Ammonium Chloride	Yes (¥)			Table 10		
07632-50-0	Ammonium citrate	Yes (¥)					§
37475-88-0	Ammonium Cumene Sulfonate	Yes (¥)					§
01341-49-7	Ammonium hydrogen-difluoride	Yes (¥)					
06484-52-2	Ammonium nitrate	Yes (¥)					
07727-54-0	Ammonium Persulfate / Diammonium peroxidisulphate	Yes (¥)					
01762-95-4	Ammonium Thiocyanate	Yes			Table 10		
	Anionic copolymer	Yes					
07440-36-0	Antimony		Yes	0.006	Table 6	Tables 1,5	0.006
07664-41-7	Aqueous ammonia	Yes	Yes		Table 7	Tables 1,5	
12672-29-6	Aroclor 1248		Yes		Table 6		0.0005
	Aromatic hydrocarbons	Yes					§§
	Aromatic ketones	Yes					§§
07440-38-2	Arsenic		Yes	0.01	Table 6	Tables 1,5	0.01
12174-11-7	Attapulgite Clay	Yes					
07440-39-3	Barium		Yes	2	Table 7	Tables 1,5	2
	Barium Strontium P.S. (mg/L)		Yes				
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex / organophilic clay	Yes					
00071-43-2	Benzene	Yes	Yes	0.005	Table 6	Tables 1,5	0.005
119345-04-9	Benzene, 1,1'-oxybis, tetrapropylene derivatives, sulfonated, sodium salts	Yes					0.05
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide	Yes					0.05
122-91-8	Benzenemethanol,4-methoxy-, 1-formate	Yes					0.05
1300-72-7	Benzenesulfonic acid, Dimethyl-, Sodium salt (aka Sodium xylene sulfonate)	Yes					0.05
00050-32-8	Benzo(a)pyrene		Yes		Table 6		0.0002

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00205-99-2	Benzo(b)fluoranthene		Yes			Tables 1,5	0.05
00191-24-2	Benzo(ghi)perylene		Yes		Table 6	Table 3	0.05
00207-08-9	Benzo(k)fluoranthene		Yes		Table 6	Tables 1,5	0.05
140-11-4	Benzyl acetate	Yes					0.05
00100-51-6	Benzyl alcohol		Yes		Table 8	Table 3	0.05
07440-41-7	Beryllium		Yes	0.004	Table 6	Tables 1,5	0.004
	Bicarbonates (mg/L)		Yes		Table 10		
76-22-2	Bicyclo (2.2.1) heptan-2-one, 1,7,7-trimethyl-	Yes					0.05
	Biochemical Oxygen Demand		Yes		Yes		
00111-44-4	Bis(2-Chloroethyl) ether		Yes		Table 6	Tables 1,5	0.005
00117-81-7	Bis(2-ethylhexyl)phthalate / Di(2-ethylhexyl)phthalate		Yes	0.006	Table 6	Tables 1,5	0.006
68153-72-0	Blown lard oil amine	Yes					\$\$
68876-82-4	Blown rapeseed amine	Yes					\$\$
1319-33-1	Borate Salt	Yes					
10043-35-3	Boric acid	Yes					
01303-86-2	Boric oxide / Boric Anhydride	Yes					
07440-42-8	Boron		Yes		Table 7	Tables 1,5	
24959-67-9	Bromide		Yes		Table 7	Tables 1,5	
00075-25-2	Bromoform		Yes		Table 6	Tables 1,5	0.005*
00071-36-3	Butan-1-ol	Yes			Table 10	Tables 1,5	
68002-97-1	C10 - C16 Ethoxylated Alcohol	Yes					\$\$
68131-39-5	C12-15 Alcohol, Ethoxylated	Yes					\$\$
07440-43-9	Cadmium		Yes	0.005	Table 6	Tables 1,5	0.005
07440-70-2	Calcium		Yes		Table 8		
1317-65-3	Calcium Carbonate	Yes			Table 10		
10043-52-4	Calcium chloride	Yes (¥)					
1305-62-0	Calcium Hydroxide	Yes					
1305-79-9	Calcium Peroxide	Yes					
00124-38-9	Carbon Dioxide	Yes	Yes				
00075-15-0	Carbondisulfide		Yes		Table 8	Tables 1,5	
68130-15-4	Carboxymethylhydroxypropyl guar	Yes					\$\$\$
09012-54-8	Cellulase / Hemicellulase Enzyme	Yes					\$\$\$
09004-34-6	Cellulose	Yes					\$\$\$

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	Cesium 137		Yes	Via beta radiation			Via beta radiation
	Chemical Oxygen Demand		Yes		Yes		
	Chloride		Yes		Table 7	Tables 1,5	250
10049-04-4	Chlorine Dioxide	Yes		MRDL=0.8	Table 10		MRDL=0.8
00124-48-1	Chlorodibromomethane		Yes		Table 6	Tables 1,5	0.005*
00067-66-3	Chloroform		Yes		Table 6	Tables 1,5	0.005*
78-73-9	Choline Bicarbonate	Yes					§
67-48-1	Choline Chloride	Yes					§
91-64-5	Chromen-2-one	Yes					0.05
07440-47-3	Chromium		Yes	0.1	Table 6	Tables 1,5	0.1
00077-92-9	Citric Acid	Yes					0.05
94266-47-4	Citrus Terpenes	Yes					§§
07440-48-4	Cobalt		Yes		Table 7	Table 1	
61789-40-0	Cocamidopropyl Betaine	Yes					0.05
68155-09-9	Cocamidopropylamine Oxide	Yes					0.05
68424-94-2	Coco-betaine	Yes					0.05
	Coliform, Total		Yes	0.05	Table 7		
	Color		Yes		Table 7		
07440-50-8	Copper		Yes	TT; Action Level=1.3	Table 6	Tables 1,5	Action Level = 1.3
07758-98-7	Copper (II) Sulfate	Yes (¥)					
14808-60-7	Crystalline Silica (Quartz)	Yes		Via solids and TSS			
07447-39-4	Cupric chloride dihydrate	Yes (¥)					
00057-12-5	Cyanide		Yes	0.2	Table 6	Tables 1,5	0.2
00319-85-7	Cyclohexane (beta BHC)		Yes		Table 6	Tables 1,5	0.005
00058-89-9	Cyclohexane (gamma BHC)		Yes	0.0002	Table 6	Tables 1,5	0.0002
1490-04-6	Cyclohexanol,5-methyl-2-(1-methylethyl)	Yes					0.05
8007-02-1	Cymbopogon citratus leaf oil	Yes					§§
8000-29-1	Cymbopogon winterianus jowitt oil	Yes					§§
01120-24-7	Decyldimethyl Amine	Yes (¥)					0.05
02605-79-0	Decyl-dimethyl Amine Oxide	Yes (¥)					0.05
00055-70-3	Dibenz(a,h)anthracene		Yes			Table 3	0.05

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03252-43-5	Dibromoacetonitrile	Yes			Table 9	Tables 1	0.05
00075-27-4	Dichlorobromomethane		Yes		Table 6	Tables 1,5	0.005*
25340-17-4	Diethylbenzene	Yes					0.05
00111-46-6	Diethylene Glycol	Yes			Table 10		0.05
22042-96-2	Diethylenetriamine penta (methylenephonic acid) sodium salt	Yes					0.05
28757-00-8	Diisopropyl naphthalenesulfonic acid	Yes					0.05
68607-28-3	Dimethylcocoamine, bis(chloroethyl) ether, diquatarnary ammonium salt	Yes					0.05
07398-69-8	Dimethyldiallylammonium chloride	Yes					0.05
00084-74-2	Di-n-butyl phthalate		Yes		Table 6	Tables 1,5	0.05
00122-39-4	Diphenylamine		Yes		Table 7	Tables 1,5	0.005
25265-71-8	Dipropylene glycol	Yes					0.05
34590-94-8	Dipropylene glycol methyl ether	Yes					0.05
00139-33-3	Disodium Ethylene Diamine Tetra Acetate	Yes					0.05
64741-77-1	Distillates, petroleum, light hydrocracked	Yes					§§
05989-27-5	D-Limonene	Yes					0.05
00123-01-3	Dodecylbenzene	Yes					0.05
27176-87-0	Dodecylbenzene sulfonic acid	Yes					0.05
42504-46-1	Dodecylbenzenesulfonate isopropanolamine	Yes					0.05
00050-70-4	D-Sorbitol / Sorbitol	Yes					0.05
37288-54-3	Endo-1,4-beta-mannanase, or Hemicellulase	Yes					0.05
00959-98-8	Endosulfan I		Yes		Table 6	Table 3	0.05
33213-65-9	Endosulfan II		Yes		Table 6	Table 3	0.05
07421-93-4	Endrin aldehyde		Yes		Table 6	Tables 1,5	0.005
149879-98-1	Erucic Amidopropyl Dimethyl Betaine	Yes					0.05
00089-65-6	Erythorbic acid, anhydrous	Yes					0.05
54076-97-0	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer	Yes					0.05
00107-21-1	Ethane-1,2-diol / Ethylene Glycol	Yes	Yes		Table 7	Tables 1,5	0.05
111-42-2	Ethanol, 2,2-iminobis-	Yes					0.05
26027-38-3	Ethoxylated 4-nonylphenol	Yes					0.05
09002-93-1	Ethoxylated 4-tert-octylphenol	Yes					0.05
68439-50-9	Ethoxylated alcohol	Yes					§§

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126950-60-5	Ethoxylated alcohol	Yes					§§
68951-67-7	Ethoxylated alcohol (C14-15)	Yes					§§
68439-46-3	Ethoxylated alcohol (C9-11)	Yes					§§
66455-15-0	Ethoxylated Alcohols	Yes					§§
67254-71-1	Ethoxylated Alcohols (C10-12)	Yes					§§
84133-50-6	Ethoxylated Alcohols (C12-14 Secondary)	Yes					§§
68439-51-0	Ethoxylated Alcohols (C12-14)	Yes					§§
78330-21-9	Ethoxylated branch alcohol	Yes					§§
34398-01-1	Ethoxylated C11 alcohol	Yes					§§
78330-21-8	Ethoxylated C11-14-iso, C13-rich alcohols	Yes					§§
61791-12-6	Ethoxylated Castor Oil	Yes					§§
61791-29-5	Ethoxylated fatty acid, coco	Yes					§§
61791-08-0	Ethoxylated fatty acid, coco, reaction product with ethanolamine	Yes					§§
68439-45-2	Ethoxylated hexanol	Yes					§§
09036-19-5	Ethoxylated octylphenol	Yes					0.05
09005-67-8	Ethoxylated Sorbitan Monostearate	Yes					0.05
09005-70-3	Ethoxylated Sorbitan Trioleate	Yes					0.05
118-61-6	Ethyl 2-hydroxybenzoate	Yes					0.05
00064-17-5	Ethyl alcohol / ethanol	Yes					0.05
00100-41-4	Ethyl Benzene	Yes	Yes	0.7	Table 6	Tables 1,5	0.005
93-89-0	Ethyl benzoate	Yes					0.05
00097-64-3	Ethyl Lactate	Yes					0.05
09003-11-6	Ethylene Glycol-Propylene Glycol Copolymer (Oxirane, methyl-, polymer with oxirane)	Yes					0.05
00075-21-8	Ethylene oxide	Yes			Table 9	Tables 1,5	0.05
05877-42-9	Ethyl octynol	Yes					0.05
8000-48-4	Eucalyptus globulus leaf oil	Yes					§§
61790-12-3	Fatty Acids	Yes					§§
68604-35-3	Fatty acids, C 8-18 and C18-unsaturated compounds with diethanolamine	Yes					§§
68188-40-9	Fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea	Yes					§§
09043-30-5	Fatty alcohol polyglycol ether surfactant	Yes					§§

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07705-08-0	Ferric chloride	Yes			Table 10		
07782-63-0	Ferrous sulfate, heptahydrate	Yes					
00206-44-0	Fluoranthene		Yes		Table 6	Tables 1,5	0.05
00086-73-7	Fluorene		Yes		Table 6	Tables 1,5	0.05
16984-48-8	Fluoride		Yes	4	Table 7	Tables 1,5	2.2
00050-00-0	Formaldehyde	Yes			Table 8	Tables 1,5	
29316-47-0	Formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane	Yes					0.05
153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide	Yes					0.05
00075-12-7	Formamide	Yes					0.05
00064-18-6	Formic acid	Yes			Table 10		0.05
00110-17-8	Fumaric acid	Yes			Table 10		0.05
65997-17-3	Glassy calcium magnesium phosphate	Yes					
00111-30-8	Glutaraldehyde	Yes					0.05
00056-81-5	Glycerol / glycerine	Yes					0.05
09000-30-0	Guar Gum	Yes					0.05
64742-94-5	Heavy aromatic petroleum naphtha	Yes					0.05
09025-56-3	Hemicellulase	Yes					0.05
00076-44-8	Heptachlor		Yes	0.0002		Tables 1,5	0.0004
01024-57-3	Heptachlor epoxide		Yes	0.0002		Tables 1,5	0.0002
	Heterotrophic plate count		Yes	TT ²⁵			
07647-01-0	Hydrochloric Acid / Hydrogen Chloride / muriatic acid	Yes					
07722-84-1	Hydrogen Peroxide	Yes			Table 10		
64742-52-5	Hydrotreated heavy naphthenic distillate	Yes					§§
00079-14-1	Hydroxy acetic acid	Yes					0.05
35249-89-9	Hydroxyacetic acid ammonium salt	Yes					0.05
09004-62-0	Hydroxyethyl cellulose	Yes					0.05
05470-11-1	Hydroxylamine hydrochloride	Yes					0.05
39421-75-5	Hydroxypropyl guar	Yes					0.05
00193-39-5	Indeno(1,2,3-cd)pyrene		Yes		Table 6	Tables 1,5	0.05

²⁵ Treatment Technology specified.

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07439-89-6	Iron		Yes		Table 7	Tables 1,5	0.3
35674-56-7	Isomeric Aromatic Ammonium Salt	Yes					0.05
64742-88-7	Isoparaffinic Petroleum Hydrocarbons, Synthetic	Yes					§§
00064-63-0	Isopropanol	Yes			Table 10		0.05
00098-82-8	Isopropylbenzene (cumene)	Yes	Yes		Table 9	Tables 1,5	0.005
68909-80-8	Isoquinoline, reaction products with benzyl chloride and quinoline	Yes					0.05
08008-20-6	Kerosene	Yes					§§
64742-81-0	Kerosine, hydrodesulfurized	Yes					§§
00063-42-3	Lactose	Yes					
8022-15-9	Lavandula hybrida abrial herb oil	Yes					§§
07439-92-1	Lead		Yes	TT; Action Level 0.015	Table 6	Tables 1,5	Action level = 0.015
64742-95-6	Light aromatic solvent naphtha	Yes					§§
01120-21-4	Light Paraffin Oil	Yes					§§
	Lithium		Yes		Table 10		
07439-95-4	Magnesium		Yes		Table 7	Tables 1,5	
546-93-0	Magnesium Carbonate	Yes					
1309-48-4	Magnesium Oxide	Yes					
1335-26-8	Magnesium Peroxide	Yes					
14807-96-6	Magnesium Silicate Hydrate (Talc)	Yes					
07439-96-5	Manganese		Yes		Table 7	Tables 1,5	0.3
07439-97-6	Mercury		Yes	0.002	Table 6	Tables 1,5	0.002
01184-78-7	Methanamine, N,N-dimethyl-, N-oxide	Yes					0.05
00067-56-1	Methanol	Yes	Yes		Table 10		0.05
119-36-8	Methyl 2-hydroxybenzoate	Yes					0.05
00074-83-9	Methyl Bromide		Yes		Table 6	Tables 1,5	0.005
00074-87-3	Methyl Chloride / chloromethane		Yes	0.005	Table 6	Tables 1,5	0.005
00078-93-3	Methyl ethyl ketone / 2-Butanone		Yes		Table 7	Tables 1,5	0.05
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched	Yes					0.05
08052-41-3	Mineral spirits / Stoddard Solvent	Yes					§§

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64742-46-7	Mixture of severely hydrotreated and hydrocracked base oil	Yes					§§
07439-98-7	Molybdenum		Yes		Table 7		
00141-43-5	Monoethanolamine	Yes					0.05
44992-01-0	N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride	Yes					0.05
64742-48-9	Naphtha (petroleum), hydrotreated heavy	Yes					§§
00091-20-3	Naphthalene	Yes	Yes		Table 6	Tables 1,5	0.05
38640-62-9	Naphthalene bis(1-methylethyl)	Yes					0.05
00093-18-5	Naphthalene, 2-ethoxy-	Yes					0.05
68909-18-2	N-benzyl-alkyl-pyridinium chloride	Yes					0.05
68139-30-0	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	Yes					0.05
07440-02-0	Nickel		Yes		Table 6	Tables 1,5	
	Nitrate, as N		Yes	10	Table 7	Tables 1,5	10
07727-37-9	Nitrogen, Liquid form	Yes					
	Nitrogen, Total as N		Yes			Table 5	
00086-30-6	N-Nitrosodiphenylamine		Yes		Table 6	Tables 1,5	0.05
26027-38-3	Nonylphenol Ethoxylate	Yes					0.05
68412-54-4	Nonylphenol Polyethoxylate	Yes					0.05
	Oil and Grease		Yes			Table 5	
8000-27-9	Oils, cedarwood	Yes					§§
121888-66-2	Organophilic Clays	Yes					
	Oxyalkylated alkylphenol	Yes					0.05
628-63-7	Pentyl acetate	Yes					0.05
540-18-1	Pentyl butanoate	Yes					0.05
8009-03-8	Petrolatum	Yes					§§
64742-65-0	Petroleum Base Oil	Yes					§§
	Petroleum distillate blend	Yes					
64742-52-5	Petroleum Distillates	Yes					§§
	Petroleum hydrocarbons		Yes				
64741-68-0	Petroleum naphtha	Yes					0.05
	pH		Yes			Table 5	

CAS Number	Parameter Name	Used in Additives ^{18,19}	Found in Flowback ²⁰	USEPA MCL or TT (mg/L) ^{21,22}	SPDES Tables ²³	TOGS111 Tables	NYS MCL, (mg/L) ²⁴
00085-01-8	Phenanthrene		Yes		Table 6	Tables 1,5	0.05
00108-95-2	Phenol		Yes		Table 6	Tables 1,5	0.05
	Phenols		Yes		Table 6	Tables 1,5	
101-84-8	Phenoxybenzene	Yes					0.05
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, ammonium salt	Yes					§
57723-14-0	Phosphorus		Yes		Table 7	Table 1	
08000-41-7	Pine Oil	Yes					§§
8002-09-3	Pine oils	Yes					§§
60828-78-6	Poly(oxy-1,2-ethanediyl), a-[3,5-dimethyl-1-(2-methylpropyl)hexyl]-w-hydroxy-	Yes					§§§
25322-68-3	Poly(oxy-1,2-ethanediyl), a-hydro-w-hydroxy / Polyethylene Glycol	Yes					§§§
24938-91-8	Poly(oxy-1,2-ethanediyl), α-tridecyl- ω-hydroxy	Yes					§§§
31726-34-8	Poly(oxy-1,2-ethanediyl),alpha-hexyl-omega-hydroxy	Yes					§§§
9004-32-4	Polyanionic Cellulose	Yes					§§§
51838-31-4	Polyepichlorohydrin, trimethylamine quaternized	Yes					§§§
56449-46-8	polyethylene glycol oleate ester	Yes					§§§
	Polyethoxylated alkanol	Yes					
9046-01-9	Polyethoxylated tridecyl ether phosphate	Yes					§§
63428-86-4	Polyethylene glycol hexyl ether sulfate, ammonium salt	Yes					§
62649-23-4	Polymer with 2-propenoic acid and sodium 2-propenoate	Yes					§§§
	Polymeric Hydrocarbons	Yes					§§
09005-65-6	Polyoxyethylene Sorbitan Monooleate	Yes					0.05
61791-26-2	Polyoxylated fatty amine salt	Yes					0.05
65997-18-4	Polyphosphate	Yes					
07440-09-7	Potassium		Yes		Table 8		
00127-08-2	Potassium acetate	Yes					§

CAS Number	Parameter Name	Used in Additives ^{18,19}	Found in Flowback ²⁰	USEPA MCL or TT (mg/L) ^{21,22}	SPDES Tables ²³	TOGS111 Tables	NYS MCL, (mg/L) ²⁴
1332-77-0	Potassium borate	Yes					
12712-38-8	Potassium borate	Yes					
20786-60-1	Potassium borate	Yes					
00584-08-7	Potassium carbonate	Yes					
07447-40-7	Potassium chloride	Yes					§
00590-29-4	Potassium formate	Yes					
01310-58-3	Potassium Hydroxide	Yes			Table 10		
13709-94-9	Potassium metaborate	Yes					
24634-61-5	Potassium Sorbate	Yes					§
112926-00-8	Precipitated silica / silica gel	Yes					
00057-55-6	Propane-1,2-diol, or Propylene glycol	Yes	Yes		Table 10	Table 3 ²⁶	1.0
00057-55-6	Propylene glycol						1.0
00107-98-2	Propylene glycol monomethyl ether	Yes			Table 10		0.05
00110-86-1	Pyridine		Yes		Table 7	Tables 1,5	0.05
68953-58-2	Quaternary Ammonium Compounds	Yes			Table 9	Tables 1	§§
62763-89-7	Quinoline,2-methyl-, hydrochloride	Yes					0.05
15619-48-4	Quinolinium, 1-(phenylmethyl),chloride	Yes					0.05
8000-25-7	Rosmarinus officinalis l. leaf oil	Yes					§§
00094-59-7	Safrole		Yes		Table 8	Table 3	0.05
	Salt of amine-carbonyl condensate	Yes					
	Salt of fatty acid/polyamine reaction product	Yes					
	Scale Inhibitor (mg/L)		Yes				
07782-49-2	Selenium		Yes	0.05	Table 6	Tables 1,5	0.05
07631-86-9	Silica, Dissolved	Yes			Table 8		
07440-22-4	Silver		Yes		Table 6	Tables 1,5	0.1
07440-23-5	Sodium		Yes		Table 7	Tables 1,5	
05324-84-5	Sodium 1-octanesulfonate	Yes					§
00127-09-3	Sodium acetate	Yes					§
95371-16-7	Sodium Alpha-olefin Sulfonate	Yes					§
00532-32-1	Sodium Benzoate	Yes					§
00144-55-8	Sodium bicarbonate	Yes					

²⁶ TOGS lists this parameter as CAS 58-55-6.

CAS Number	Parameter Name	Used in Additives ^{18,19}	Found in Flowback ²⁰	USEPA MCL or TT (mg/L) ^{21,22}	SPDES Tables ²³	TOGS111 Tables	NYS MCL, (mg/L) ²⁴
07631-90-5	Sodium bisulfate	Yes					
07647-15-6	Sodium Bromide	Yes					
00497-19-8	Sodium carbonate	Yes					
07647-14-5	Sodium Chloride	Yes					
07758-19-2	Sodium chlorite	Yes					1.0 (chlorite)
03926-62-3	Sodium Chloroacetate	Yes					§
00068-04-2	Sodium citrate	Yes					§
06381-77-7	Sodium erythorbate / isoascorbic acid, sodium salt	Yes					§
02836-32-0	Sodium Glycolate	Yes					§
1301-73-2	Sodium hydroxide	Yes					
01310-73-2	Sodium Hydroxide	Yes			Table 10		
07681-52-9	Sodium hypochlorite	Yes			Table 10		
07775-19-1	Sodium Metaborate .8H2O	Yes					
10486-00-7	Sodium perborate tetrahydrate	Yes					
07775-27-1	Sodium persulphate	Yes					
68608-26-4	Sodium petroleum sulfonate	Yes					
09003-04-7	Sodium polyacrylate	Yes					§
07757-82-6	Sodium sulfate	Yes			Table 10		
01303-96-4	Sodium tetraborate decahydrate	Yes					
07772-98-7	Sodium Thiosulfate	Yes					
01338-43-8	Sorbitan Monooleate	Yes					0.05
	Specific Conductivity		Yes				
07440-24-6	Strontium		Yes		Table 9	Table 1	
00057-50-1	Sucrose	Yes					
	Sugar	Yes					
05329-14-6	Sulfamic acid	Yes					
14808-79-8	Sulfate		Yes		Table 7	Tables 1,5	250
	Sulfide		Yes		Table 7	Tables 1,5	
14265-45-3	Sulfite		Yes		Table 7	Table 1	
	Surfactant blend	Yes					
68442-77-3	Surfactant: Modified Amine	Yes					§§
	Surfactants MBAS		Yes				

CAS Number	Parameter Name	Used in Additives ^{18,19}	Found in Flowback ²⁰	USEPA MCL or TT (mg/L) ^{21,22}	SPDES Tables ²³	TOGS111 Tables	NYS MCL, (mg/L) ²⁴
112945-52-5	Synthetic Amorphous / Pyrogenic Silica / Amorphous Silica	Yes					
68155-20-4	Tall Oil Fatty Acid Diethanolamine	Yes					§§
08052-48-0	Tallow fatty acids sodium salt	Yes					§,§§
72480-70-7	Tar bases, quinoline derivs., benzyl chloride-quaternized	Yes					§§
68647-72-3	Terpene and terpenoids	Yes					§§
68956-56-9	Terpene hydrocarbon byproducts	Yes					§§
00127-18-4	Tetrachloroethylene		Yes	0.005	Table 6	Tables 1,5	0.005
00533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione / Dazomet	Yes					0.05
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate (THPS)	Yes					0.05
00075-57-0	Tetramethyl ammonium chloride	Yes					§
00064-02-8	Tetrasodium Ethylenediaminetetraacetate	Yes					§
07440-28-0	Thallium		Yes	0.002	Table 6	Tables 1,5	0.002
00068-11-1	Thioglycolic acid	Yes					0.05
00062-56-6	Thiourea	Yes			Table 10		0.05
68527-49-1	Thiourea, polymer with formaldehyde and 1-phenylethanone	Yes					§§§
68917-35-1	Thuja plicata donn ex. D. don leaf oil	Yes					§§
07440-32-6	Titanium		Yes		Table 7		
00108-88-3	Toluene	Yes	Yes	1	Table 6	Tables 1,5	0.005
	Total Dissolved Solids		Yes			Table 5	
	Total Kjeldahl Nitrogen		Yes		Yes		
	Total Organic Carbon		Yes		Yes		
	Total Suspended Solids		Yes		Yes		
81741-28-8	Tributyl tetradecyl phosphonium chloride	Yes					§
	Triethanolamine	Yes					0.05
68299-02-5	Triethanolamine hydroxyacetate	Yes					0.05
00112-27-6	Triethylene Glycol	Yes					0.05
52624-57-4	Trimethylolpropane, Ethoxylated, Propoxylated	Yes					§§
00150-38-9	Trisodium Ethylenediaminetetraacetate	Yes					§
05064-31-3	Trisodium Nitrilotriacetate	Yes					§0.05

CAS Number	Parameter Name	Used in Additives ^{18,19}	Found in Flowback ²⁰	USEPA MCL or TT (mg/L) ^{21,22}	SPDES Tables ²³	TOGS111 Tables	NYS MCL, (mg/L) ²⁴
07601-54-9	Trisodium ortho phosphate	Yes					
00057-13-6	Urea	Yes					0.05
07440-62-2	Vanadium		Yes		Table 7	Table 1	
25038-72-6	Vinylidene Chloride/Methylacrylate Copolymer	Yes					§§§
	Volatile Acids		Yes		27		
7732-18-5	Water	Yes					
8042-47-5	White Mineral Oil	Yes					§§
11138-66-2	Xanthan gum	Yes					§§§
	Xylenes	Yes	Yes	10		Table 1,5	0.005
13601-19-9	Yellow Sodium of Prussiate	Yes					
07440-66-6	Zinc		Yes		Table 6	Tables 1,5	5.0
	Zirconium		Yes				0.05
							§,§§

²⁷ Several volatile compounds regulated via SPDES Table 6. Need to evaluate constituents.

6.1.3.4 Potential Impacts to Primary and Principal Aquifers

An uncontained and unmitigated surface spill could result in rapid contamination of a portion of a Primary or Principal aquifer.

Aside from the NYC Watershed and water supply system, about one half of New Yorkers rely on groundwater as a source of potable water. To enhance regulatory protection in areas where groundwater resources are most highly productive and vulnerable, NYSDOH identified categories of areas for use in geographic targeting. In order of priority, these areas are designated as follows: public water supply wellhead areas; primary water supply aquifer areas; principal aquifer areas; and other areas. The Department's Division of Water Technical & Operational Guidance Series (TOGS) 2.1.3 clarifies the meaning of Primary Water Supply Aquifer (also referred to as a Primary Aquifer) and Principal Aquifer. TOGS 2.1.3 further defines "highly vulnerable" areas as "aquifers which are highly susceptible to contamination from human activities at the land surface over the identified aquifer." This TOGS also further defines "highly productive" aquifers as those "with capability to provide water for public water supply of a quantity and natural background quality which is of regional significance."

NYSDOH identified eighteen Primary Aquifers across New York State, defined in TOGS 2.1.3 as "highly productive aquifers presently utilized as sources of water supply by major municipal water supply systems." Primary Aquifers are generally capable of providing more than 100 gallons of drinking water per minute from an individual well.

NYSDOH has also identified Principal Aquifers, which are defined in the TOGS as "highly productive but which are not intensively used as sources of water supply by major municipal systems at the present time." The TOGS further states that these areas need special protections, but awards Principal Aquifers a slightly lower priority than that afforded Primary Aquifers. Principal Aquifers are used by individual households, as well as smaller public water supply systems, such as schools or restaurants. However, Principal Aquifers are generally capable of providing 10 to 100 or more gpm of drinking water. Principal Aquifers could become Primary Aquifers depending on future public water supply use.

The groundwater table in the Primary and Principal Aquifers generally ranges from 0 to 20 feet in depth, and is overlain with sands and gravels. Because Primary and Principal Aquifers are largely located and contained in unconsolidated material (i.e., sand and gravel), the high permeability of soils that overlie these aquifers and the shallow depth to the water table make these aquifers particularly susceptible to contamination from surface activity. TOGS 2.1.3 notes that the aquifer designations provide a rationale for enhancing regulatory protections beyond those provided by existing programs including the SPDES, Chemical Bulk Storage, and Solid and Hazardous Wastes.

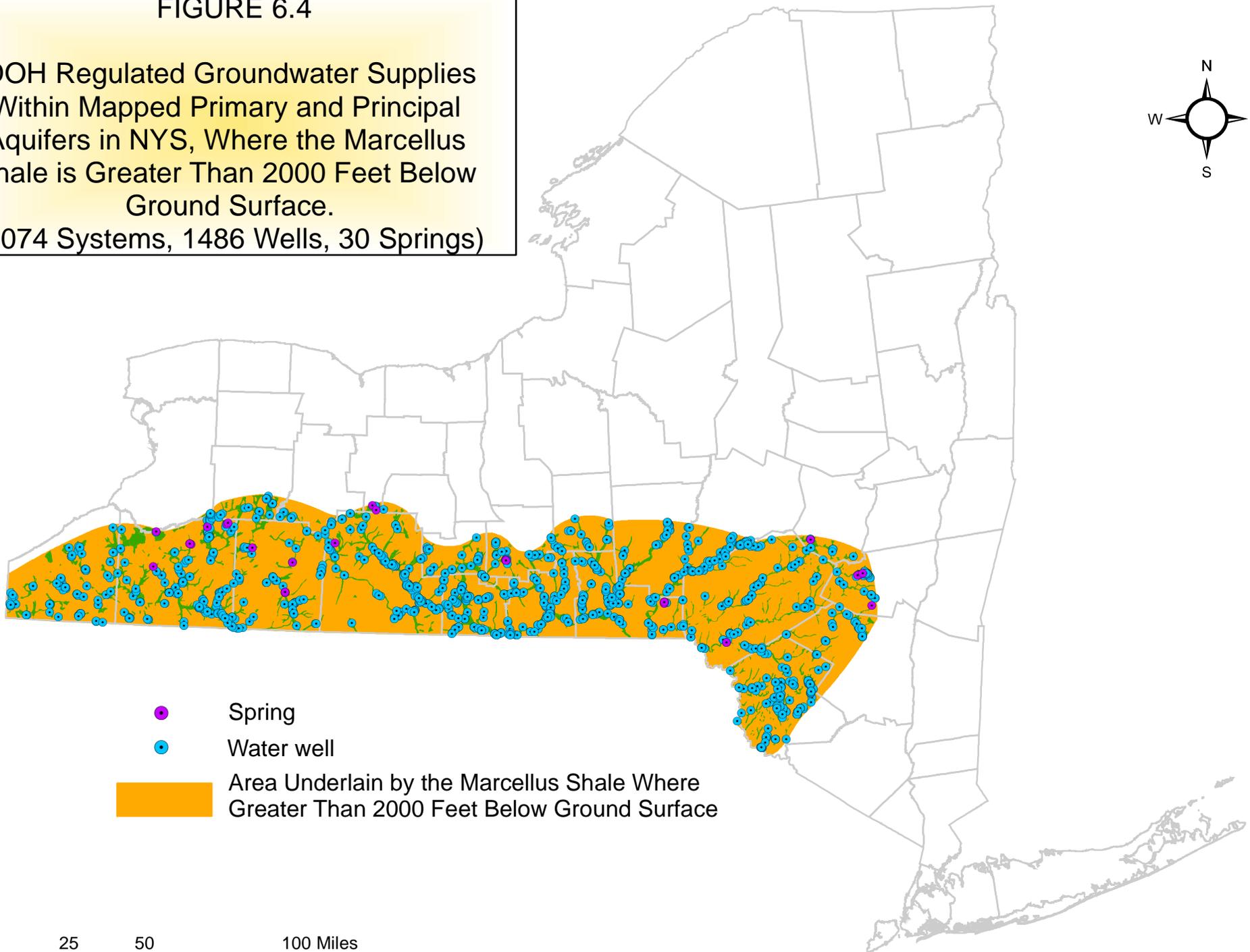
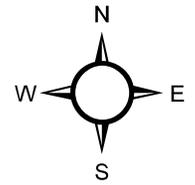
The Department has issued regulations prohibiting installation of certain facilities that threaten these aquifers. For example, 6 NYCRR Part 360 "Solid Waste Facilities" provides that landfills are generally not permitted to be constructed above, or within, Primary or Principal Aquifer areas. Likewise, the Department has, since 1982, inserted special conditions into permits for drilling oil, gas and other ECL 23 wells within the boundaries of these aquifers.

As an example of the number and distribution of public supply systems that rely on Primary and Principal Aquifers within areas that could be developed by high-volume hydraulic fracturing, Figure 6.4 depicts public water supply systems that draw from Primary and Principal Aquifers within the area underlain by the Marcellus Shale where the shale occurs at a depth of at least 2,000 feet below the ground surface. The Primary Aquifer areas in this area follow the major river valleys, and serve hundreds of public water supplies, including a number of significantly sized municipalities, such as Binghamton and Endicott, as well as their surrounding areas. There are approximately 1,074 public supply systems that rely on Primary and Principal Aquifers in this area, and the total population served by these combined water supplies is at least 544,740. The total population within the area is approximately 906,000. Therefore, roughly 60.1% of the population in this prospective area is served by community groundwater supplies that draw from Primary and Principal Aquifer areas. The remainder of the population in this area is served by individual private wells or public surface water supplies or community supplies outside of Primary and Principal Aquifer areas.

FIGURE 6.4

**DOH Regulated Groundwater Supplies
Within Mapped Primary and Principal
Aquifers in NYS, Where the Marcellus
Shale is Greater Than 2000 Feet Below
Ground Surface.**

(1074 Systems, 1486 Wells, 30 Springs)



● Spring

● Water well

■ Area Underlain by the Marcellus Shale Where
Greater Than 2000 Feet Below Ground Surface



The Department is chiefly concerned with surface contamination in Primary and Principal Aquifer areas because of the risk that uncontained and unmitigated surface spills could reach the aquifer in a short amount of time, due to the permeable character of the soils above the aquifers, and the shallow depth to the aquifers (generally 0-20 feet below the ground). Water quality management programs for such aquifers focus on preventing contaminants from reaching the waters in the first instance, because once they become contaminated, it is difficult and expensive to reclaim an aquifer as a source of drinking water.

As discussed elsewhere, detailed well pad containment requirements and setbacks proposed for high-volume hydraulic fracturing are likely to effectively contain most surface spills at and in the vicinity of well pads. Nevertheless, despite the best controls, there is a risk of releases to Primary or Principal Aquifers of chemicals, petroleum products and drilling fluids from the well pad.

Therefore, the Department concludes that high-volume hydraulic fracturing operations have the potential to cause a significant adverse impact to the quality of the drinking water resources provided by Primary and Principal Aquifers, even if the risk of such events is relatively small.

Conclusion

The Department finds that the proposed high-volume hydraulic fracturing operations, although temporary in nature, may pose risks to Primary and Principal Aquifers that are not fully mitigated by the measures identified in this SGEIS.

The proposed activity could result in a degradation of drinking water supplies from accidents, construction activity, runoff and surface spills. Accordingly, the Department concludes that high-volume hydraulic fracturing operations within Primary and Principal Aquifers pose the risk of causing significant adverse impacts to water resources. As discussed in Chapter 7, standard mitigation measures may only partially mitigate such impacts. Such partial mitigation would be unacceptable due to the potential consequences posed by such impacts.

6.1.4 Groundwater Impacts Associated With Well Drilling and Construction

The wellbore being drilled, completed or produced, or a nearby wellbore that is ineffectively sealed, has the potential to provide subsurface pathways for groundwater pollution from well drilling, flowback or production operations. Pollutants could include:

- turbidity;
- fluids pumped into or flowing from rock formations penetrated by the well; and
- natural gas present in the rock formations penetrated by the well.

These potential impacts are not unique to horizontal wells and are described by the 1992 GEIS. The unique aspect of the proposed multi-well development method is that continuous or intermittent activities would occur over a longer period of time at any given well pad. This does not alter the per-well likelihood of impacts from the identified subsurface pathways because existing mitigation measures apply on an individual well basis regardless of how many wells are drilled at the same site. Nevertheless, the potential impacts are acknowledged here and enhanced procedures and mitigation measures are proposed in Chapter 7 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. As mentioned earlier, the 1992 GEIS addressed hydraulic fracturing in Chapter 9, and NYSDOH's review did not identify any potential exposure situations associated with horizontal drilling and high-volume hydraulic fracturing that are qualitatively different from those addressed in the 1992 GEIS.

6.1.4.1 Turbidity

The 1992 GEIS stated that “review of Department complaint records revealed that the most commonly validated impact from oil and gas drilling activity on private water supplies was a short-term turbidity problem.”²⁸ This remains the case today. Turbidity, or suspension of solids in the water supply, can result from any aquifer penetration (including monitoring wells, water wells, oil and gas wells, mine shafts and construction pilings) if sufficient porosity and permeability or a natural subsurface fracture is present to transmit the disturbance. The majority of these situations correct themselves in a short time.

²⁸ NYSDEC 1992, GEIS, p. 47.

6.1.4.2 Fluids Pumped Into the Well

Fluids for hydraulic fracturing are pumped into the wellbore for a short period of time per fracturing stage, until the rock fractures and the proppant has been placed. For each horizontal well the total pumping time is generally between 40 and 100 hours. ICF International, under its contract with NYSERDA to conduct research in support of SGEIS preparation, provided the following discussion and analysis with respect to the likelihood of groundwater contamination by fluids pumped into a wellbore for hydraulic fracturing (emphasis added):²⁹

In the 1980s, the American Petroleum Institute (API) analyzed the risk of contamination from properly constructed Class II injection wells to an Underground Source of Drinking Water (USDW) due to corrosion of the casing and failure of the casing cement seal. Although the API did not address the risks for production wells, production wells would be expected to have a lower risk of groundwater contamination due to casing leakage. Unlike Class II injection wells which operate under sustained or frequent positive pressure, a hydraulically fractured production well experiences pressures below the formation pressure except for the short time when fracturing occurs. During production, the wellbore pressure would be less than the formation pressure in order for formation fluids or gas to flow to the well. *Using the API analysis as an upper bound for the risk associated with the injection of hydraulic fracturing fluids, the probability of fracture fluids reaching a USDW due to failures in the casing or casing cement is estimated at less than 2×10^{-8} (fewer than 1 in 50 million wells).*

More recently, regulatory officials from 15 states have testified that groundwater contamination as a result of hydraulic fracturing, which includes this pumping process, has not occurred (Appendix 15).

6.1.4.3 Natural Gas Migration

As discussed above, turbidity is typically a short-term problem which corrects itself as suspended particles settle. The probability of groundwater contamination from fluids pumped into a properly-constructed well is very low. Natural gas migration is a more reasonably anticipated risk posed by high-volume hydraulic fracturing. The 1992 GEIS, in Chapters 9, 10 and 16, describes the following scenarios related to oil and gas well construction where natural gas could migrate into potable groundwater supplies:

²⁹ ICF Task 1, 2009, p. 21.

- Inadequate depth and integrity of surface casing to isolate potable fresh water supplies from deeper gas-bearing formations;
- Inadequate cement in the annular space around the surface casing, which may be caused by gas channeling or insufficient cement setting time; gas channeling may occur as a result of naturally occurring shallow gas or from installing a long string of surface casing that puts potable water supplies and shallow gas behind the same pipe; and
- Excessive pressure in the annulus between the surface casing and intermediate or production casing. Such pressure could break down the formation at the shoe of the surface casing and result in the potential creation of subsurface pathways outside the surface casing. Excessive pressure could occur if gas infiltrates the annulus because of insufficient production casing cement and the annulus is not vented in accordance with required casing and cementing practices.

As explained in the 1992 GEIS, potential migration of natural gas to a water well 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. Well construction practices designed to prevent gas migration would also form a barrier to other formation fluids such as oil or brine. Although gas migration may not manifest itself until the production phase, its occurrence would result from well construction (i.e., casing and cement) problems.

The 1992 GEIS 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 document explains how the natural occurrence of shallow methane in New York can affect water wells, which needs to be considered when evaluating complaints of methane migration that are perceived to be related to natural gas development.

6.1.5 Unfiltered Surface Drinking Water Supplies: NYC and Syracuse

There are two major surface drinking water sources and systems located within New York that have been granted permission by EPA and NYSDOH to operate as unfiltered drinking water supplies pursuant to regulations promulgated under the federal SDWA, known as the Surface Water Treatment Rule (SWTR). These unfiltered systems are the NYC and City of Syracuse water supplies and associated watersheds. For a drinking water system to qualify for filtration avoidance under the SWTR, the system cannot be the source of a waterborne disease outbreak, must meet source water quality limits for coliform and turbidity and meet coliform and total

trihalomethane MCLs in finished water. Disinfectant residual levels and redundant disinfection capability also must be maintained. Filtration avoidance further requires that a watershed control program be implemented to minimize microbial contamination of the source water. This program must characterize the watershed's hydrology, physical features, land use, source water quality and operational capabilities. It must also identify, monitor and control manmade and naturally occurring activities that are detrimental to water quality. The watershed control program must also be able to control activities through land ownership or written agreements.

Heightened public health sensitivities are associated with unfiltered surface water systems because the only treatment that these drinking waters receive before human consumption is basic disinfection through such methods as chlorine addition or ultraviolet light irradiation. In unfiltered systems, there is no application of widely employed treatment measures such as chemical coagulation/flocculation or physical filtration to remove pathogens, sediments, organic matter or other contaminants from the drinking water.

The NYC drinking water supply watershed (NYC Watershed) is located in portions of Delaware, Dutchess, Greene, Putnam, Schoharie, Sullivan, Ulster and Westchester Counties.

Approximately 9.4 million residents rely on the NYC water supply: 8.4 million in NYC and 1 million in portions of Orange, Putnam, Ulster and Westchester Counties. The NYC Watershed contains 19 reservoirs and 3 controlled lakes that supply, on average, 1.1 to 1.3 billion gallons of potable water daily. Historically, 90% of this system's drinking water has been supplied by the "Catskill" and "Delaware" portions of the NYC Watershed, which are located west of the Hudson River (an area that may be described as the "Catskill/Delaware Watershed"). On average, the remaining 10% of the water supply flows from the "Croton" portion of the NYC Watershed that is located in the counties to the east of the Hudson River. An extensive system of aqueducts and tunnels transmit waters by gravity throughout the NYC Watershed and water supply system. The NYC Watershed covers 2,000 square miles, an area that comprises 4.2% of the total land area of New York State.

Eight of the reservoirs located in the Croton portion of the NYC Watershed have been formally determined by the Department, pursuant to Clean Water Act sec. 303(d), to be impaired due to excess nutrient phosphorus (Amawalk, Croton Falls, Diverting, East Branch, Middle Branch,

Muscoot, New Croton and Titicus Reservoirs). Designation as "impaired" means that these reservoirs are in a condition that violates state water quality standards due to a specified pollutant. The Cannonsville Reservoir in Delaware County previously had been declared to be impaired due to excess nutrient phosphorus; however, its status was improved by active water quality remedial management efforts, including wastewater treatment plant upgrades, septic system repairs and replacements, construction of stormwater retrofits, and installation of best management practices on several hundred farms located throughout the Catskill and Delaware Watershed, most notably in Delaware County. As a result of this comprehensive and aggressive watershed protection program, the Department has determined that the Cannonsville Reservoir has been returned to regulatory compliance. The two reservoirs located in the Catskill portion of the NYC Watershed have been determined by the Department to be impaired due to excessive levels of suspended sediment (Ashokan and Schoharie Reservoirs).

The most recent EPA Filtration Avoidance Determination (FAD) was granted to NYC by EPA, in consultation with NYSDOH, in 2007 for the unfiltered use of the Catskill and Delaware systems and interconnected reservoir basins located in watershed communities to the east of the Hudson River. Waters flowing from the Croton portion of the NYC Watershed have been required to be filtered by EPA (at a cost of approximately \$3 billion for construction of the filtration plant). Systems of aqueducts and interchanges, however, allow for Croton waters to be transferred and intermixed with waters from the Catskill and Delaware systems to assure an adequate water supply in stressed or emergency situations, such as significant drought or major infrastructure failure.

The City of Syracuse, with a population of approximately 145,000, has also been granted permission by EPA and NYSDOH to operate an unfiltered drinking water supply. The most recent filtration avoidance determination was issued by NYSDOH to Syracuse in 2004. The unfiltered source water is Skaneateles Lake, a Finger Lake that is located approximately 20 miles to the south and west of Syracuse. The Skaneateles Lake watershed comprises a total area of 59 square miles that includes the lake - which is approximately 14 miles long and 1 mile wide. Reports issued by the Syracuse Department of Water state that Skaneateles Lake generally provides between 32 and 34 million gallons of potable water daily. The most recent NYSDOH source water assessment found that Skaneateles Lake had a moderate susceptibility to

contamination, including a level of farm pasture land that results in a high potential for protozoan contamination. Copper sulfate treatments are at times administered to Skaneateles Lake to control phosphorus-induced algae growth and associated adverse impacts such as poor taste and odor.

6.1.5.1 Pollutants of Critical Concern in Unfiltered Drinking Water Supplies

One of the fundamental concepts framing the effective protection of unfiltered drinking water is "source water protection." Management programs in such watershed necessarily focus on systematically preventing contaminants from reaching the waters in the first instance, as there is no mechanism in place (such as a filtration plant) to remove contaminants once they have entered the water. Once polluted, it very difficult and very expensive to return these water supplies back to their original condition. In both the NYC and City of Syracuse watersheds, extensive efforts have been undertaken to stringently treat sewage discharges. Within the Skaneateles Lake watershed, any discharge, whether treated sewage effluent or otherwise, to any surface water is prohibited. Within the NYC Watershed, all sewage treatment plants must achieve an extraordinarily stringent level of treatment consistent with "tertiary treatment, micro-filtration and biological phosphorus removal." These are the most technologically advanced sewage treatment plants in New York State. Therefore, the critical remaining potential for impairment of these two unfiltered water supplies stems from human activities that place contaminants on the ground that can then be washed into reservoirs and tributaries via storm water runoff, or flow into them from contaminated groundwater.

The National Research Council of the National Academies of Sciences undertook a detailed assessment of the risks and sensitivities associated with the NYC Watershed and water supply system. This peer-reviewed report provides useful background on the distinctive nature of risks resulting from potential surface pollution in unfiltered drinking water watersheds and supplies.³⁰ The concerns and management methods discussed in this report are also relevant and applicable to the City of Syracuse drinking water supply.

In general, the pollutants of key concern when managing an unfiltered drinking water system are: (i) nutrient phosphorus; (ii) microbial pathogens; (iii) suspended sediment (or "turbidity"); and

³⁰ National Research Council, 2000.

(iv) toxic compounds. As explained below, the adverse impacts of these contaminants are substantially heightened in unfiltered drinking water systems.

Phosphorus: Excess phosphorus leads to algae blooms, including increased growth of toxin emitting blue-green algae. Algae blooms lead to high bacteria growth (due to bacterial consumption of algae) that, in turn, deplete the reservoir bottom waters of dissolved oxygen. Low dissolved oxygen suffocates or drives off fish. Low oxygen levels cause a change in the biology of reservoir waters (to anaerobic conditions) that result in impaired water taste, odor, and color. For example, iron, manganese and H₂S are brought into the water column under these low oxygen conditions. The higher levels of dead algae, bacteria and other chemicals in the water constitute an increase in organic matter that can react with chlorine during the drinking water disinfection process - causing elevated levels of "disinfection by-products"; many of these chlorinated organic compounds are suspected by the EPA of being carcinogens and have been identified in a number of medical studies as a factor linked to early term miscarriage. Finally, the increased material suspended in water, which results from phosphorus-induced algae blooms, can interfere with the effectiveness of chlorination and ultraviolet light irradiation on pathogens, and thereby foster the transport waterborne pathogens to water consumers.

Phosphorus is a naturally-occurring element that is found in human and animal wastes, animal and plant materials, fertilizers and eroded soil particles. While essential for life, excess phosphorus at very low levels can cause the adverse environmental and public health impacts discussed above during the warm weather growing season. Guidance value concentrations, set by the Department to limit adverse impacts from phosphorus in NYC Watershed reservoirs, range between 15 and 20 parts per billion (ppb).

Microbial Pathogens: A surface drinking water source may be adversely impacted by a range of disease-causing microorganisms such as bacteria, viruses and protozoa. Such organisms can result from a variety of sources but to a significant extent result from human and animal wastes or possible re-growth in bio-slimes that may form within a drinking water supply system. Both the NYC and Syracuse drinking water supplies are required by EPA and NYSDOH regulations to employ two forms of disinfection in series that, when combined with effective source water

protection programs, are highly effective in destroying or de-activating bacteria, viruses and protozoa.

However, there are two disinfection-resistant protozoa that have emerged in recent decades that can cause significant intestinal illness in otherwise healthy humans, and result in severe illness and even death in individuals with compromised immune systems. These protozoa, *Giardia lamblia* and *Cryptosporidium parvum*, both have life stages where they form cysts (or oocysts) that can survive standard disinfection treatments and infect human hosts. The basic public health management response to such organisms is to limit specific human and animal waste transmission pathways to waters on the landscape and to require controls that limit such occurrences as algae blooms and suspended sediments, which can assist in the transmittal of pathogens. As discussed below, inadequately effective controls will likely result in the imposition of a costly filtration requirement by EPA or NYSDOH in accordance with the SDWA and the underlying SWTR.

Sediment or Turbidity: Sediment laden, or turbid, water can increase the effective transportation of pathogens, serve as food for pathogens, promote the re-growth of pathogens in the water distribution system, and shelter pathogens from exposure to attack by disinfectants such as chlorine or ultraviolet light. The organic particles that are a cause of turbidity can combine with chlorine to create problematic disinfection by-products that are possible carcinogens and suspected by medical studies of increasing the risk of miscarriage.

EPA, in its SWTR, prohibits raw water turbidity measurements in unfiltered drinking water at the intake to the distribution system in excess of 5 nephelometric turbidity units (essentially, very clear water).³¹ More than one violation per year is grounds for EPA or NYSDOH to require construction of a water filtration plant. Such a plant for the Catskill and Delaware portions of the NYC water supply has been estimated to cost between \$8 to \$10 billion with an additional \$200 (plus) million a year in operational and maintenance expenses. An overview of the public health concerns raised by turbidity in drinking water are discussed in greater detail at: *U.S. EPA, Guidance Manual for Compliance with the Interim Enhanced Surface Water Treatment Rule: Turbidity Provisions*, Office of Water, EPA 815-R-99-010, April 1999, Chapter 7 (and numerous

³¹ 40 CFR §141.71(a)(2).

cited references); *see also* Kistemann, T., *et al.*, *Microbial Load of Drinking Water Reservoir Tributaries During Extreme Rainfall and Runoff*, *Applied Environmental Microbiology*, Vol. 68, No. 5, pp. 2188-2197 (May 2002); Naumova, E., *et al.*, *The Elderly and Waterborne Cryptosporidium Infection: Gastroenteritis Hospitalizations Before and During the 1993 Milwaukee Outbreak*, *Emerging Infectious Diseases*, Vol. 9 No. 4, pp. 418-425 (2003).

Toxic Compounds: Unfiltered drinking water supplies have a heightened sensitivity to chemical discharges as there is no immediately available method to remove contaminants from the drinking water source waters. Well pad containment practices and setbacks are likely to effectively contain most spills at those locations. There is a continuing risk, however, of releases from chemicals, petroleum products and drilling fluids from the well pad 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. The intensive level of trucking activity associated with high-volume hydraulic fracturing, including the transport of chemical and petroleum products, presents an additional risk of surface water contamination due to truck accidents and associated releases. Given the topography of much of the NYC and Skaneateles Lake watersheds, many of the roadways are in immediate proximity to tributaries. Such proximity increases the risk that chemical and petroleum spills would not, or could not, be effectively intercepted before entering the drinking water supply.

6.1.5.2 Regulatory and Programmatic Framework for Filtration Avoidance

The basic statutory and regulatory framework applicable to unfiltered drinking water supplies is provided by the federal Safe Drinking Water Act (SDWA), 42 U.S.C. sec. 300f, et al. The SDWA directed EPA to adopt regulations requiring public water supplies using surface waters to apply filtration systems to treat their water unless protective "criteria" or "standards" could be met. Pursuant to this grant of authority, EPA issued the SWTR, 40 CFR sec. 141.71, et al. Subject to continuing oversight, EPA has delegated authority to administer the SDWA within New York to the NYSDOH pursuant to State statutory and regulatory authority that is consistent with the federal protocol.

There are numerous "filtration avoidance criteria" specified in the SWTR. These criteria must be met for a drinking water supply system to maintain its unfiltered status. The first two criteria address fecal coliform and turbidity limits in raw water before disinfection. The next four criteria address assuring the effectiveness of disinfection and the maintenance of sufficient levels of disinfection agents in the water distribution system. The next five criteria variously address landscape control programs for *Giardia lamblia*, water supply system inspections, prohibition on waterborne disease outbreaks, and maximum contaminant level compliance for total coliform and disinfection by-products in drinking water after disinfection.

Another key provision operates to drive overarching watershed planning and protection programs, along with cooperative agreements with individuals and municipalities situated within the unfiltered watershed: "The public water system must demonstrate through ownership and/or written agreements with landowners within the watershed that it can control *all human activities which may have an adverse impact on the microbiological quality of the source water.*" 40 CFR sec. 141.71(b)(2)(iii) (emphasis added). High-volume hydraulic fracturing and associated activities are within the scope of "human activities" covered by this regulatory provision. As discussed above, human activities that increase levels of phosphorus and sediment, or heighten storm water flows that could transmit microbial pathogens into waters, would all have an "impact on the microbiological quality of the source water."

Major efforts have been undertaken to cooperatively assure equitable implementation of programs to protect the NYC Watershed and water supply. In 1997, essentially all stakeholders associated with the NYC Watershed entered into the "1997 New York City Watershed Memorandum of Agreement." This binding three volume agreement specified extensive programs with respect to land acquisition, extra-territorial regulations promulgated by NYC, the establishment of a Watershed Protection and Partnership Council, and an array of specific programs to limit pollution from septic systems, construction excavations, salt storage facilities, runoff from impervious surfaces, timber harvesting, waste water treatment plants, unstable streams and farms. An extensive and updated source water protection program also is detailed in the FAD that was issued to NYC (covering environmental infrastructure, protection and remedial water quality efforts, watershed monitoring and regulatory implementation). Protection programs, as well as programs to equitably address the concerns of local residents, were also

detailed in a Department Water Supply Permit that was finalized and issued to NYC in January 2011. It is estimated that at least \$1.6 billion has been invested in NYC Watershed protection programs since 1997.

Syracuse has developed similar programs to prevent contamination of Skaneateles Lake and its watershed. Specific regulations have been developed to address a range of human activities that could adversely impact water quality – including sewage treatment plants, septic systems, and erosion and sediment controls at construction sites. Syracuse implements a "Watershed Agricultural Program" to cooperatively limit pollution that could result from crop land and animal agricultural activities. A program of conservation easements in certain sensitive lands has also been developed to limit human activity that might harm water quality.

6.1.5.3 Adverse Impacts to Unfiltered Drinking Waters from High-Volume Hydraulic Fracturing Activities associated with high-volume hydraulic fracturing involve a significant amount of land clearing and excavation. New roads, sufficient to reach the well pad and of a design capable of handling a high volume of fully loaded truck traffic, would need to be cleared and cut. The often steep terrain of the NYC and Skaneateles Lake watersheds would necessitate a significant level of cut and fill roadway excavations, as well as soil stockpiles, that would expose soils to erosive activities. The excavation and grading of level well pads (generally ranging from 3 to 5 acres in size) to support drilling activities would create significant additional amounts of exposed soils and cut and fill excavations. Gas transmission pipelines of various sizes would necessarily be cut through the watersheds, often in straight lines and down hills in a manner that can accelerate and channelize water during precipitation events. Both the NYC Watershed and Skaneateles Lake watershed regularly receive high precipitation events that operate to mobilize exposed soil particles.

The clearing of vegetation, and the excavation and compaction of soils, associated with new roads, pipelines and drilling well pads in the NYC and Skaneateles Lake watersheds also will increase the volume and intensity of stormwater runoff, even if subject to stormwater control. While not fully "impervious" this less pervious landscape will increase runoff. Moreover, to support high volumes of truck traffic, narrow existing dirt roads may need to be paved and widened, as has been the experience in Pennsylvania. One acre of impervious surface is

estimated to create the same amount of runoff as 16 acres of naturally vegetated meadow or forest.³² Therefore, new impervious surfaces (as well as the substantially less-pervious surfaces created by the removal of vegetation and compaction of soils associated with construction excavations) can transmit very high volumes of stormwater relative to natural conditions that then operate to destabilize road-side ditches and streams, and cause additional erosion. As discussed, elevated turbidity or suspended sediment levels present particular public health concerns in an unfiltered drinking water supply, a problem that already significantly affects the Catskill portion of the NYC Watershed, including the Schoharie and Ashokan Reservoirs.

As in other areas of the state, erosion and sediment control measures would significantly limit the adverse impacts of stormwater flow from construction excavations, erosion, soils compaction and increased imperviousness associated with high-volume hydraulic fracturing. However, even with such stormwater controls, the heightened sensitivity of these unfiltered watersheds make the potential for adverse impacts to water quality from sedimentation due to construction excavations significant during levels of projected peak activity. Even with state-of-the art stormwater controls a risk of increased stormwater runoff from accidents or other unplanned events cannot be entirely eliminated. The potential consequences of such events – loss of the FAD – is significant even if the risk of such events occurring is relatively small. Similarly, the risks associated with high volumes of truck traffic transporting chemical and petroleum products associated with high-volume hydraulic fracturing is inconsistent with effective protection of an unfiltered drinking water supply. This is especially so, as a number of factors, discussed above, are already operating to stress the NYC and Syracuse source waters. This concern is exemplified by an extensive study by researchers from SUNY ESF and Yale published in 2008. This peer-reviewed report concluded that the current rate of excavations and associated increases in impervious and less pervious surfaces within the NYC Watershed would likely result in the phosphorus impairment of all reservoirs over an approximate 20 year time frame. Hall, M., R. Germain, M. Tyrell, and N. Sampson, *Predicting Future Water Quality from Land Use Change Projections in the Catskill-Delaware Watersheds*, pp. 217-268 (2008) (available at <http://www.esf.edu/es/faculty/hall.asp>). This report does not take into consideration the accelerated development associated with high-volume hydraulic fracturing.

³² Schuler, 1994, p. 100.

6.1.5.4 Conclusion

The Department finds that high-volume hydraulic fracturing activity is not consistent with the preservation of the NYC and Syracuse watersheds as unfiltered drinking water supplies. Even with all of the criteria and conditions identified in the revised draft SGEIS, 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 FADs and result in the affected municipalities incurring substantial costs to filter their drinking water supply.

Accordingly, and for all of the aforementioned reasons, the Department concludes that high-volume hydraulic fracturing operations within the NYC and Syracuse watersheds pose the risk of causing significant adverse impacts to water resources. As discussed in Chapter 7, standard mitigation measures such as stormwater controls would only partially mitigate such impacts. Such partial mitigation is unacceptable due to the potential consequences – adverse impacts to human health and loss of filtration avoidance – posed by such impacts.

6.1.6 Hydraulic Fracturing Procedure

Concern has been expressed that potential impacts to groundwater from the high-volume hydraulic fracturing procedure itself could result from:

- wellbore failure as a result of an improperly constructed well; or
- movement of unrecovered fracturing fluid out of the target fracture formation through subsurface pathways such as:
 - a nearby poorly constructed or improperly plugged wellbore;
 - fractures created by the hydraulic fracturing process;
 - natural faults and fractures; and
 - movement of fracturing fluids through the interconnected pore spaces in the rocks from the fracture zone to a water well or aquifer.

As summarized in Section 8.4.5, regulatory officials from 15 states have recently testified that groundwater contamination from the hydraulic fracturing procedure is not known to have occurred despite the procedure's widespread use in many wells over several decades.

Nevertheless, NYSEERDA contracted ICF International to evaluate factors which affect the likelihood of groundwater contamination from high-volume hydraulic fracturing.³³

6.1.6.1 Wellbore Failure

As described in Section 6.1.4.2, the probability of fracture fluids reaching an underground source of drinking water (USDW) from properly constructed wells due to subsequent failures in the casing or casing cement due to corrosion is estimated at less than 2×10^{-8} (fewer than 1 in 50 million wells). Hydraulic fracturing is not known to cause wellbore failure in properly constructed wells.

6.1.6.2 Subsurface Pathways

Reference is made in Section 5.9 to ICF International's calculations of the rate at which fracturing fluids could move away from the wellbore through fractures and the rock matrix during pumping operations under hypothetical assumptions of a hydraulic connection. Appendix 11 provides ICF's full discussion of the principles governing potential fracture fluid flow under this hypothetical condition. ICF's conclusion is that "hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers."³⁴ Specific conditions or analytical results supporting this conclusion include:

- 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;
- 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;
- 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; and

³³ ICF Task 1, 2009,

³⁴ ICF Task 1, 2009, p. 34

- Any flow of fracturing fluid toward an aquifer through open fractures or an unplugged wellbore would be reversed during flowback, with any residual fluid further flushed by flow from the aquifer to the production zone as pressures decline in the reservoir during production.

As noted in Section 2.4.6, a depth of 850 feet to the base of potable water is a commonly used and practical generalization for the maximum depth of potable water in New York. Alpha Environmental, under its contract with NYSEDA, provided the following additional information regarding the Marcellus and Utica Shales:³⁵

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

Natural Controls on Underground Fluid Migration

As noted by ICF (Subpart 5.11.1.1 and Appendix 11) and Alpha (as cited above) , 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. Figure 4.2 shows that 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 rocks 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 a significant length of time, implying that there is no mechanism for discharge.

As previously discussed, 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

³⁵ Alpha, 2009, p. 3-3.

diminished once the rock has fractured, and is reversed toward the wellbore during the flowback and production phases.

Darcy's Law is a universally accepted scientific principle of hydrogeology. It states the relationship that explains fluid flow in porous media. Flow rate, Q, is calculated by

$$Q=KA(P_{\text{high}}-P_{\text{low}})/\mu L$$

where K= permeability, A= cross sectional area, P=pressure, μ =fluid viscosity and L=length of flow. The factor “ $P_{\text{high}}-P_{\text{low}}$ ” describes a pressure differential, and Darcy’s Law explains the relationship between pressure and fluid flow. During hydraulic fracturing operations, the pressure in the well is greater than the pressure in the formation and drives the fluid and sand into the rock creating the induced fractures. If induced fractures do intersect an open fault or wellbore that diverts fluid from the target formation during pumping, this would be detected by required pressure monitoring during the fracturing process. Permit conditions will require pumping operations to cease if this occurs, until the anomalous condition is evaluated and addressed. Cessation of pumping will remove the pressure differential and stop further flow away from the target formation. Additionally, the force exerted by lithostatic pressure (i.e., the weight of overlying rocks) tends to close natural fissures at depth, so even when such fissures exist they are not necessarily transmissive. This is the reason that hydraulic fracturing requires the use of proppant to keep induced fractures open to transmit natural gas to the wellbore. Also, even if it is assumed that fractures in overlying strata are transmissive, there is no reason to believe that the fractures of different strata are aligned in a manner that would make hydraulic connections possible.

Once pumping ceases and hydraulic fracturing is accomplished, the well is turned into the production system at the surface which is at a much lower pressure than the formation. Therefore gas flows to the well and the surface. At this point there is no pressure differential that would cause fluid to move in any direction other than towards the gas well.

All of the above factors that inhibit vertical fracturing fluid migration would also inhibit horizontal migration beyond the fracture zone for the distances required to impact potable water wells in the Marcellus and other shales from high-volume hydraulic fracturing under the

conditions specified by ICF. Because of regional dip, the geographic location of any target reservoir where it is more than 1,000 feet below the presumed base of fresh water would be at least several miles south of any location where water wells are completed in the same rock formation.

Mapped Marcellus Hydraulic Fracturing Stages

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.³⁶ 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.

6.1.7 Waste Transport

Drilling and fracturing fluids, mud-drilled cuttings, pit liners, flowback water and production brine are classified as non-hazardous industrial-commercial waste which would be hauled under a New York State Part 364 waste transporter permit issued by the Department. All Part 364 transporters would identify the general category of wastes transported and obtain written authorization from each destination facility, which must be maintained at the place of business and made available to the Department upon request.

Manifesting is not required for non-hazardous industrial-commercial waste, so there is no tracking and verification of disposal destination on an individual load basis. Although the Department's regulations do not classify drilling and production wastes as hazardous, like all wastes they must be handled and disposed of in accordance with all applicable regulatory requirements. One concern is that wastes will not be properly identified or may not be taken to appropriate, permitted facilities. Chapter 7 provides mitigation for this concern in the form 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. It should be noted that the developing practice of treating and reusing flowback water

³⁶ Fisher, 2010, pp. 30-33.

on the same well pad would reduce the number of truck trips for hauling flowback water to other destinations. Information about traffic management related to high-volume hydraulic fracturing is presented in Section 7.8.

6.1.8 *Fluid Discharges*

Direct discharge of fluids onto the ground or into surface water bodies from the well pad are prohibited. Discharges would be managed at treatment facilities, appropriately recycled, or in permitted disposal wells.

6.1.8.1 POTWs

Surface water discharges from water treatment facilities are regulated under the Department's SPDES program. Acceptance by a POTW of a waste stream that upsets its system or exceeds its capacity may result in a SPDES permit effluent violation or a violation of water quality standards within the receiving water. Water pollution degrades surface waters, potentially making them unsafe for drinking, fishing, swimming, and other activities or unsuitable for their classified best uses.

Flowback water may be sent to POTWs. However, treatability of flowback water presents a potential environmental concern because residual fracturing chemicals and naturally-occurring constituents from the rock formation could be present in flowback water and have 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. Tables 6.1, 6.2 and 6.3 provide information on flowback water composition based on a limited number of samples from Pennsylvania and West Virginia.

Appendix 21 is a list of POTWs with approved pretreatment and mini-pretreatment programs. Note that this is not a list of facilities approved to accept wastewater from high-volume hydraulic fracturing. Rather, it is a list of facilities that have SPDES permit conditions and requirements allowing them to accept wastewater from hauled or other significant industrial sources in accordance with 40CFR Part 403. To accept a source of wastewater, the 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; that analysis is known as a Maximum Allowable Headworks Loading analysis (MAHW, or headworks analysis). In addition, any industrial wastewater source, including this source of wastewater, may only be discharged utilizing all treatment processes within the POTW. Admixture of untreated flowback water or other well development water to the treated effluent of the POTW is not allowed. Improper handling could result in noncompliance with terms of the permit or the ECL and result in formal enforcement actions.

The large volumes of return water from high-volume hydraulic fracturing combined with the diverse mixture of chemicals and high concentrations of TDS that exist in both flowback water and production water, requires that the permittee submit a headworks analysis specific to the parameters expected present in high-volume hydraulic fracturing wastewater, including TDS and NORM, to both the Department and EPA Region 2 for review in accordance with DOW's Technical and Operational Guidance Series (TOGS) 1.3.8, *New Discharges to Publicly Owned Treatment Works*. TOGS 1.3.8., was developed to assist Department permit writers in evaluating the potential effect of a new, substantially increased, or changed non-domestic discharge to a POTW on that facility's SPDES permit and pretreatment program. The DOW and EPA must determine whether the POTW has adequately evaluated the effects of the proposed discharge on POTW operation, sludge disposal, effluent quality, and POTW health and safety; whether the discharge will result in the discharge of a substance that will be subject to effluent limits, action levels, or other monitoring requirements in the facility's SPDES permit; and whether the proposed discharge contains any Bioaccumulative Chemicals of Concern or persistent toxic substances that may be subject to SPDES effluent limits or other Departmental permit requirements or controls. Appendix C of TOGS 1.3.8, *Guidance for Acceptance of New Discharges*, describes the analyses and submittals necessary for a POTW to accept a new source of wastewater. Note that if a facility has a currently approved headworks analysis in place for the parameters and concentrations of those parameters typically found in flowback water and production water, the permittee may assess the impacts of the proposed discharge against the existing headworks analysis.

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.

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.

Specific information regarding high volume hydraulic fracturing additives, such as chemical makeup and aquatic toxicity, will be required for this analysis. A complete listing of all ingredients in each chemical additive to be used shall be included as part of a headworks analysis, along with aquatic toxicity data for each of the additives. If any confidentiality is allowed under State law based upon the existence of proprietary material, that fact may be noted in the submission. However, in no circumstance shall a fracturing additive be approved or evaluated in a headworks analysis without aquatic toxicity data. Department approval of the

headworks analysis, and the modification of the POTW's SPDES permit if necessary, must be received prior to the acceptance of flowback water or production water from wells permitted pursuant to this Supplement.

In conducting the headworks analysis, the parameters that must be analyzed include, at a minimum:

- pH, range, SU;
- Oil and Grease;
- Solids, Total Suspended;
- Solids, Total Dissolved;
- Chloride;
- Sulfate;
- Alkalinity, Total (CaCO₃);
- BOD, 5 day;
- Chemical Oxygen Demand (COD);
- Total Kjeldahl Nitrogen (TKN);
- Ammonia, as N;
- Total Organic Carbon;
- Phenols, Total;
- the following scans:
 - Priority Pollutants Metals;
 - Priority Pollutants VOC;
 - Priority Pollutants SVOC Base/Neutral; and
 - Priority Pollutants SVOC Acid Extractable;

- Radiological analysis including:
 - Gross Alpha - EPA Method 900.0, Standard Methods 7110-B;
 - Gross Beta - EPA Method 900.0, Standard Methods 7110-B;
 - Radium - EPA Method 903.0, Standard Methods 7500-Ra B;
 - Uranium - EPA Method 908, Standard Methods 7500-U;and
 - Thorium - EPA Method 910, Standard Methods 7500-Th;
- constituents that were present in the hydraulic fracturing additives.

The high concentrations of TDS present in this source of wastewater may prove to be inhibitory to biological wastewater treatment systems. It has been noted that the concentrations of TDS in the return and process water increase as a higher percentage of native water is produced and then stabilize over the life of the well. The expected concentrations of TDS for both the initial flowback water as well as for the ongoing well operation must therefore be considered in the development of the headworks analysis. It is incumbent upon the POTW to determine whether the volumes and concentrations of chemicals present in the flowback water or production water would result in adverse impacts to the facility's treatment processes as part of the above headworks analysis.

The Department has performed a very basic analysis to determine the potential available capacity for POTWs to accept high-volume hydraulic fracturing wastewater. The Department estimates that the POTWs within the approximate area of shale development in New York have an aggregate available flow capacity of approximately 300 MGD, which is the difference between existing flow and permitted flow. Based on this capacity, an estimate was developed to determine the existing total treatment capacity based on the actual flows, existing TDS levels and allowable TDS discharge limits. This estimate was based on a conservative assumption of influent TDS from production water. This estimate assumes that all of these POTWs would be willing to accept this wastewater to their maximum available capacity, and that no other increased discharges or other growth in the service area are expected. A TDS level of 350,000 mg/L will be used, as this is on the upper end of expected concentrations. Discharge levels from POTWs would be limited to 1,000 mg/L. Typical influent levels of TDS at a POTW are

approximately 300 mg/L. Therefore, a typical POTW can be expected to have a disposal capacity of approximately 700 mg/L (1,000 – 300mg/L) of TDS. Again assuming an influent level of 350,000 mg/L of TDS and a disposal capacity of 700 mg/L at an existing POTW, the dilution ratio of existing POTW flow to allowable high-volume hydraulic fracturing wastewater influent flow is 500:1 (350,000 divided by 700). Based on this analysis, the maximum total capacity for disposal of high-volume hydraulic fracturing wastewater is estimated to be less than 1 MGD. The estimated production water per well may range from 400 gpd to 3,400 gpd depending on the life of the well.

The above analysis is subject to a number of assumptions which, when actual conditions are factored in, will limit the available capacity to much less than 1 MGD. The analysis assumes that the treatment facilities are willing to accept this source of wastewater; following its December 2008 letter to POTWs outlining the requirements to accept high-volume hydraulic fracturing wastewater, the Division of Water has yet to receive any requests from any POTW in the State to accept this source of wastewater. The analysis assumes that POTWs are equipped to take this source of wastewater and that haulers are willing to pump the waste into the POTW at the rate that will be required to protect the POTW; no POTWs in New York State currently have TDS-specific treatment technologies, so the ability to accept this wastewater is limited by influent concentration and flow rates. The analysis assumes that the receiving water has assimilative capacity to accept additional TDS loadings from POTWs and that the background TDS in the receiving water is less than the in-stream water quality standard of 500 mg/L; there are several streams in New York State which cannot accept additional TDS loads. Based on the above, there is questionable available capacity for POTWs in New York State to accept high-volume hydraulic fracturing wastewater.

Case Study: One wellpad is expected to have 8 wells. Each well is expected to produce 3,000 gallons of production water. Assuming 3,000 gpd x 8 wells = 24,000 gpd. With a 500:1 ratio needed for disposal, a POTW with an existing flow of 12 mgd would be needed to dispose of the production water from this single wellpad.

Further, because of the inability of biological treatment systems to remove certain high-volume hydraulic fracturing additives in flowback water, as previously described, POTWs are not

usually equipped to accept influent containing these contaminants. The potential for inhibition of biological activity and sludge settling and the potential for radionuclide concentration in the sludge impacts sludge disposal options.

As noted previously, acceptance of wastewater from high-volume hydraulic fracturing operations must consider the impacts to POTW operation, sludge disposal, effluent quality, and POTW health and safety. Concentrations of NORM, specifically radium, in natural gas drilling wastewater have the potential to impact POTW sludge disposal. At this time there is a lack of detailed information on levels of NORM in POTW sludge and to what extent NORM that is introduced to a POTW is concentrated in the sludge. Therefore, to ensure that POTW sludge disposal is not affected, an influent radium-226 limit of 15 pCi/L for high-volume hydraulic fracturing wastewater, to be determined prior to admixture with other POTW influents, would be required in SPDES permits for any POTW that proposes to accept high-volume hydraulic fracturing wastewater. It is noted that there are a number of water bodies in NY where the ambient levels of TDS already exceed the water quality standard or where TDS has already been fully allocated in existing SPDES permits. This may further limit the ability of POTWs to accept these discharges.

6.1.8.2 Private Off-site Wastewater Treatment and/or Reuse Facilities

Privately owned facilities built specifically for the reuse and/or treatment and disposal of industrial wastewater from high-volume hydraulic fracturing operate in other states, including Pennsylvania. Similar facilities that might be constructed in New York would require a SPDES permit if the operator of the facility intends to discharge treated effluent to surface or groundwater. The treatment methods that would be applicable to these facilities are discussed in Chapter 5. A number of adverse impacts are possible resulting from improper maintenance or overloading of these systems, resulting in either surface or water discharges that do not comply with applicable standards. However, properly maintained and regulated systems, along with waste tracking and SPDES permitting control measures as described in Chapter 7 would mitigate the potential for these impacts. The same limitations and impacts noted regarding the effects of discharges from POTWs to the waters of the State, including the ability of the receiving water to accept additional TDS loads, as described in Section 6.1.8.1 above, also apply to privately-owned off-site treatment works.

6.1.8.3 Private On-site Wastewater Treatment and/or Reuse Facilities

As noted in Chapter 5 of this Draft SGEIS, on-site treatment of flowback water for purposes of reuse is currently being used in Pennsylvania and other states. The treated water is blended with fresh water at the well site and reused for hydraulic fracturing, with the treatment system residue hauled off-site. A number of adverse impacts are possible resulting from improper maintenance or overloading of these systems, resulting in either surface or water discharges that do not comply with applicable standards. However, properly maintained and operated treatment and/or reuse systems, along with the waste tracking measures described in Chapter 7, would mitigate the potential for these impacts. Because all applicable technology-based requirements must be applied in NPDES/SPDES permits under the Clean Water Act section 402(a) and implementing regulations at 40 CFR 125.3, an NPDES/SPDES permit issued for drilling activity would need to be consistent with 40 CFR Part 435, Subpart C, which states that “there shall be no discharge of wastewater pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (i.e. production brine, drilling muds, drill cuttings, and produced sand.”

6.1.8.4 Disposal Wells

As stated in the 1992 GEIS, the primary environmental consideration with respect to disposal wells is the potential for movement of injected fluids into or between potential underground sources of drinking water. The Department is not proposing to alter its 1992 Finding that proposed disposal wells require individual site-specific review. 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.

6.1.8.5 Other Means of Wastewater Disposal

Wastewater generated by high-volume hydraulic fracturing would be able to be treated and disposed of to the extent that available capacity exists using the disposal options referenced in Section 6.1.8.4 above. Should wastewater be generated in volumes exceeding available capacity within the State, the wastewater would require transport and disposal at facilities not located in New York State, or additional treatment facilities to be constructed. Potential impacts that may

result from insufficient wastewater treatment capacity would include either storage of wastewater and associated potential for leaks or spillage, illegal discharge of wastewater to the ground surface or directly to waters of the State, and increased truck traffic resulting from transport of wastewater to out of state treatment and disposal facilities.

6.1.9 Solids Disposal

Most waste generated at a well site is in liquid form. Rock cuttings and the reserve pit liner are the significant exception. The 1992 GEIS describes potential adverse impacts to agricultural operations if materials are buried at too shallow a depth or work their way back up to the surface. Concerns unique to Marcellus development and multi-well pad drilling are discussed below.

6.1.9.1 NORM Considerations - Cuttings

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 likely to pose a problem because – as set forth in Section 5.2.4.2 – the levels are similar to those naturally encountered in the surrounding environment.

6.1.9.2 Cuttings Volume

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. The geotechnical stability and bearing capacity of buried cuttings, if left in a common pit, may need to be reviewed prior to pit closure.³⁷

³⁷ Alpha, 2009, p. 6-7.

6.1.9.3 Cuttings and Liner Associated With Mud-Drilling

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.

6.2 Floodplains

Flooding is hazardous to life, property and structures. Chapter 2 describes Flood Damage Prevention Laws implemented by local communities to govern development in floodplains and floodways and also provides information about recent flooding events in the Susquehanna and Delaware River Basins. The GEIS summarizes the potential impacts of flood damage relative to mud or reserve pits, production brine and oil tanks, other fluid tanks, brush debris, erosion and topsoil, bulk supplies (including additives) and accidents. Severe flooding is described as “one of the few ways” that bulk supplies such as additives “might accidentally enter the environment in large quantities.”³⁸ Accordingly, construction of drill pads within flood plains raises serious and significant environmental issues and risks.

6.3 Freshwater Wetlands

State regulation of wetlands is described in Chapter 2. The 1992 GEIS summarizes the potential impacts to wetlands associated with interruption of natural drainage, flooding, erosion and sedimentation, brush disposal, increased access and pit location, and those potential impacts are applicable to high-volume hydraulic fracturing. Potential impacts to downstream wetlands as a result of surface water withdrawal are discussed in Section 6.1.1.4 of this Supplement. Other concerns described herein relative to stormwater runoff and surface spills and releases, also extend to wetlands.

6.4 Ecosystems and Wildlife

The 1992 GEIS discusses the significant habitats known to exist at the time in or near then-existing oil and gas fields (heronries, deer wintering areas, and uncommon, rare and endangered plants). Significant habitats are defined as areas that provide one or more of the key factors required for survival, variety, or abundance of wildlife, and/or for human recreation associated

³⁸ NYSDEC, 1992, GEIS, p. 8-44

with such wildlife. This section considers the potential impact of high-volume hydraulic fracturing on all terrestrial habitat types, including forests, grasslands (including old fields managed for grasslands, and pasture and hay fields) and shrublands. Four areas of concern related to high-volume hydraulic fracturing are:

- 1) fragmentation of habitat;
- 2) potential transfer of invasive species;
- 3) potential impacts on endangered and threatened species; and
- 4) use of certain State-owned lands.

When the 1992 GEIS was developed, the scale and scope of the anticipated impact of oil and gas drilling in New York State was much different than it is today. Development of low-permeability reservoirs by high-volume hydraulic fracturing have the potential to draw substantial development into New York, which is reasonably anticipated to result in potential impacts to habitats (fragmentation, loss of connectivity, degradation, etc.), species distributions and populations, and overall natural resource biodiversity.

The development of Marcellus Shale gas will have a large footprint.³⁹ In addition to direct loss of habitat, constant activity on each well pad from construction, drilling, and waste removal can be expected for 4 to 10 months, further affecting species. If a pad has multiple wells, it might be active for several years. More land is disturbed for multi-well pads, but fewer access roads, infrastructure, and total pads would be needed. Well pad sites are partially restored after drilling, but 1-3 acres is typically left open for the life of the well (as are access roads and pipelines), which is expected to be 20 to 40 years.

6.4.1 Impacts of Fragmentation to Terrestrial Habitats and Wildlife

Fragmentation is an alteration of habitats resulting in changes in area, configuration, or spatial patterns from a previous state of greater continuity, and usually includes the following:

³⁹ Environmental Law Clinic, 2010.

- Reduction in the total area of the habitat;
- Decrease of the interior to edge ratio;
- Isolation of one habitat fragment from other areas of habitat;
- Breaking up of one patch of habitat into several smaller patches; and
- Decrease in the average size of each patch of habitat.

General Direct, Indirect, and Cumulative Impacts:

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.⁴⁰

Habitat loss is the direct conversion of surface area to uses not compatible with the needs of wildlife, and can be measured by calculating the physical dimensions of well pads, roads, and other infrastructure. In addition to loss of habitat, other potential direct impacts on wildlife from drilling in the Marcellus Shale include increased mortality, increase of edge habitats, altered microclimates, and increased traffic, noise, lighting, and well flares. Existing regulation of wellhead and compressor station noise levels is designed to protect human noise receptors. Little definitive work has been done on the effects of noise on wildlife.⁴¹

Habitat degradation is the diminishment of habitat value or functionality; its indirect and cumulative effects on wildlife are often assessed through analysis of landscape metrics. Indirect and cumulative impacts may include a loss of genetic diversity, species isolation, population declines in species that are sensitive to human noise and activity or dependent on large blocks of habitat, increased predation, and an increase of invasive species. Certain life-history characteristics, including typically long life spans, slow reproductive rates, and specific habitat requirements for nesting and foraging, make raptor (birds of prey) populations especially vulnerable to disturbances. Direct habitat loss has less impact than habitat degradation through

⁴⁰ Environmental Law Clinic, 2010.

⁴¹ New Mexico Dept. Game & Fish, 2007.

fragmentation and loss of connectivity due to widespread activities like oil and gas development.⁴²

Biological systems are exceedingly complex, and there can be serious cascading ecological consequences when these systems are disturbed. Little baseline data are available with which comparisons can later be made in the attempt to document changes, or lack thereof, due to oil and gas development. In cases where serious adverse consequences may reasonably be expected, it is prudent to err on the side of caution.⁴³

Habitat fragmentation from human infrastructure has been identified as one of the greatest threats to biological diversity. Research on habitat fragmentation impacts from oil and gas development specific to New York is lacking. However, the two following studies from the western United States are presented here to illustrate qualitatively the potential impacts to terrestrial habitats that could occur in New York. A quantitative comparison between these studies and potential impacts in New York is not possible because these studies were conducted under a regulatory structure that resulted in well spacing that differs from those anticipated for high-volume hydraulic fracturing in New York. Additional research would be necessary to determine the precise impacts to species and wildlife expected from such drilling in New York's Marcellus Shale.

While fragmentation of all habitats is of conservation concern, the fragmentation of grasslands and interior forest habitats are of utmost concern in New York. Some of the bird species that depend on these habitat types are declining. This decline is particularly dramatic for grasslands where 68% of the grassland-dependent birds in New York are declining.⁴⁴

Projected Direct Impacts

Study 1, General Discussion: The Wilderness Society conducted a study in 2008⁴⁵ that provided both an analytical framework for examining habitat fragmentation and results from a

⁴² New Mexico Dept. Game & Fish, 2007.

⁴³ New Mexico Dept. Game & Fish, 2007.

⁴⁴ Post 2006.

⁴⁵ Wilbert et al., 2008.

hypothetical GIS analysis simulating the incremental development of an oil and gas field to progressively higher well pad numbers over time. Results of the sample analysis gave a preliminary estimate of the minimum potential fragmentation impacts of oil and gas development on wildlife and their habitats; the results were not intended to be a substitute for site-specific analyses.

The study identified a method to measure fragmentation (landscape metrics), and a way to tie various degrees of fragmentation to their impacts on wildlife (from literature). Two fragmentation indicator values (road density and distance-to-nearest-road or well pad) were analyzed for impacts to a few important wildlife species present in oil and gas development areas across the western U.S.

Study 1, Findings: The total area of direct disturbance from well pads and roads used in oil and gas development was identified for a hypothetical undeveloped 120-acre site, with seven separate well-pad densities - one pad per 640 acres, 320 acres, 160 acres, 80 acres, 40 acres, 20 acres, and 10 acres:

1. Well pads: the disturbance area increased approximately linearly as pad density increased;
2. Total road length: the disturbance area increased more rapidly in the early stages of development;
3. Mean road density: the rate of increase was higher at earlier stages of development. The size of the pre-development road system had an effect on the magnitude of change between subsequent development stages, but the effect decreased as development density increased;
4. Distance-to-nearest-road (or well pad): the rate of decrease was higher at earlier stages of development than at later stages; and
5. Significant negative effects on wildlife were predicted to occur over a substantial portion of a landscape, even at the lower well pad densities characteristic of the early stages of development in gas or oil fields.

This suggests that landscape-level planning for infrastructure development and analysis of wildlife impacts need to be done prior to initial development of a field. Where development has already occurred, the study authors recommend that existing impacts on local wildlife species be

measured and acknowledged, and the cumulative impacts from additional development be assessed.

Study 1, Implications for New York: The study results emphasize the importance of maintaining undeveloped areas. Note that the degree of habitat fragmentation and the associated impacts on wildlife from such development in real landscapes would be even greater than those found in the study, which used conservative estimates of road networks (no closed loops, shorter roads, and few roads pre-development) and did not include pipelines and other infrastructure.

Projected Indirect and Cumulative Impacts

Study 2, General Discussion: The Wilderness Society conducted a study in 2002⁴⁶ that analyzed the landscape of an existing gas and oil field in Wyoming to identify habitat fragmentation impacts. As fragmentation of the habitat occurred over a wide area, cumulative and indirect impacts could not be adequately addressed at the individual well pad site level. Rather, analyzing the overall ecological impacts of fragmentation on the composition, structure, and function of the landscape required a GIS spatial analysis. A variety of metrics were developed to measure the condition of the landscape and its level of fragmentation, including: density of roads and linear features; acreage of habitat in close proximity to infrastructure; and acreage of continuous uniform blocks of habitat or core areas.

Study 2, Findings: The study area covered 166 square miles, and contained 1864 wells, equaling a density of 11 wells per square mile.⁴⁷ The direct physical footprint of oil and gas infrastructure was only 4% of the study area; however, the ecological impact of that infrastructure was much greater. The entire study area was within one-half mile of a road, pipeline corridor, well head, or other infrastructure, while 97% fell within one-quarter mile. Study results also showed the total number, total acreage, and the percent of study area remaining in core areas decreased as the width of the infrastructure impact increased. No core areas remained within one-half mile of infrastructure, and only 27% remained within 500 feet of infrastructure. These results, combined with a review of the scientific literature for

⁴⁶ Weller et al. 2002.

⁴⁷ Note that this density is between that of single horizontal wells (9 per square mile) and vertical wells (16 per square mile) expected in New York (section 5.1.3.2).

fragmentation impacts to western focal species, indicated there was little to no place in the study area where wildlife would not be impacted.

Study 2, Implications for New York: This study demonstrated that impacts to wildlife extended beyond the direct effects from the land physically altered by oil and gas fields. Note that the overall impacts predicted in the study were likely conservative as the data were only assessed at the individual gas field scale, not the broader landscape. While well densities from multiple horizontal wells from a common pad (a minimum of 1 well pad per square mile) would be less than in this study, all three drilling scenarios might result in negative impacts to wildlife in New York, as the impacts predicted to the complement of species in Wyoming were so extreme.

6.4.1.1 Impacts of Grassland Fragmentation

Grassland birds have been declining faster than any other habitat-species suite in the northeastern United States.⁴⁸ The primary cause of these declines is the fragmentation of habitat caused by the abandonment of agricultural lands, causing habitat loss due to reversion to later successional stages or due to sprawl development. Remaining potential habitat is also being lost or severely degraded by intensification of agricultural practices (e.g., conversion to row crops or early and frequent mowing of hayfields).

Stabilizing the declines of populations of grassland birds has been identified as a conservation priority by virtually all of the bird conservation initiatives, groups, and agencies in the northeastern US, as well as across the continent, due to concern over how precipitous their population declines have been across portions of their ranges (for the list of species of concern and their population trends, see Table 6.2). In New York, grassland bird population declines are linked strongly to the loss of agricultural grasslands, primarily hayfields and pastures; it is therefore critical to conserve priority grasslands in order to stabilize or reverse these declining trends.

⁴⁸ Morgan and Burger 2008.

Table 6.2 - Grassland Bird Population Trends at Three Scales from 1966 to 2005.⁴⁹ (New July 2011)

Species	New York		USFWS Region 5		Survey-wide	
	trend (%/year)	population remaining (%)	trend (%/year)	population remaining (%)	trend (%/year)	population remaining (%)
Northern Harrier ¹	-3.4	25.9	1.1	153.2	-1.7	51.2
Upland Sandpiper ¹	-6.9	6.2	-0.7	76.0	0.5	121.5
Short-eared Owl ¹	--	--	--	--	-4.6	15.9
Sedge Wren ¹	-11.5	0.9	0.5	121.5	1.8	200.5
Henslow's Sparrow	-13.8	0.3	-12.6	0.5	-7.9	4.0
Grasshopper Sparrow ¹	-9.4	2.1	-5.2	12.5	-3.8	22.1
Bobolink ¹	-0.5	82.2	-0.3	88.9	-1.8	49.2
Loggerhead Shrike ¹	--	--	-11.4	0.9	-3.7	23.0
Horned Lark ²	-4.7	15.3	-2.1	43.7	-2.1	43.7
Vesper Sparrow ²	-7.9	4.0	-5.4	11.5	-1.0	67.6
Eastern Meadowlark ²	-4.9	14.1	-4.3	18.0	-2.9	31.7
Savannah Sparrow ²	-2.6	35.8	-2.3	40.4	-0.9	70.3

¹Highest priority or ²High priority for conservation

Note: Background colors correspond with "regional credibility measures" for the data as provided by the authors. **Blue** indicates no deficiencies, **Yellow** (yellow) indicates a deficiency, and **Red** indicates an important deficiency.

Bold indicates significant trends (P<0.05).

Some of New York's grassland birds have experienced steeper declines than others, or have a smaller population size and/or distribution across the state or region, and are therefore included in the highest priority tier in Table 6.2: northern harrier (*Circus cyaneus*), upland sandpiper (*Bartramia longicauda*), short-eared owl (*Asio flammeus*), sedge wren (*Cistothorus platensis*), Henslow's sparrow (*Ammodramus henslowii*), grasshopper sparrow (*Ammodramus savannarum*), bobolink (*Dolichonyx oryzivorus*), and loggerhead shrike (*Lanius ludovicianus*). Species included in the high priority tier are those that have been given relatively lower priority, but whose populations are also declining and are in need of conservation. The high priority tier in

⁴⁹ Morgan and Burger, 2008.

Table 6.2 includes: horned lark (*Eremophila alpestris*), vesper sparrow (*Pooecetes gramineus*), eastern meadowlark (*Sturnella magna*), and savannah sparrow (*Passerculus sandwichensis*).

While these birds rely on grasslands in New York as breeding habitat (in general), two of these species (northern harrier and short-eared owl) and several other raptor species also rely on grasslands for wintering habitat. For this reason, a third target group of birds are those species that rely on grassland habitats while they over-winter (or are year-round residents) in New York, and include: snowy owl (*Bubo scandiacus*), rough-legged hawk (*Buteo lagopus*), red-tailed hawk (*Buteo jamaicensis*), American kestrel (*Falco sparverius*), and northern shrike (*Lanius excubitor*).

The specific effects of drilling for natural gas on nesting grassland birds are not well studied. However, the level of development expected for multi-pad horizontal drilling and minimum patch sizes of habitat necessary for bird reproduction, unless mitigated, will result in substantial impacts from the fragmentation of existing grassland habitats. Minimum patch sizes would vary by species and by surrounding land uses, but studies have shown that a minimum patch size of between 30-100 acres is necessary to protect a wide assemblage of grassland-dependent species.⁵⁰

6.4.1.2 Impacts of Forest Fragmentation

Forest fragmentation issues were the subject of two assessments referenced below which are specific to the East and address multiple horizontal well drilling from common pads. These studies, therefore, are more directly applicable to New York than previously mentioned western studies of vertical drilling. The Multi-Resolution Land Characteristic Dataset (“MRLC”) (2004) indicates the following ratios of habitat types in the area underlain by the Marcellus shale in New York: 57% forested; 28% grassland/agricultural lands; and 3% scrub/shrub. The other 12% is divided evenly between developed land and open water/wetlands. As forests are the most common cover type, it is reasonable to assume that development of the Marcellus Shale would have a substantial impact on forest habitats and species.

⁵⁰ USFWS, Sample and Mossman 1997, Mitchell et al, 2000.

Today, New York is 63% (18.95 million acres) forested⁵¹ and is unlikely to substantially increase. Current forest parcelization and fragmentation trends will likely result in future losses of large, contiguous forested areas.⁵² Therefore, protecting these remaining areas is very important for maintaining the diversity of wildlife in New York.

The forest complex provides key ecosystem services that provide substantial ecological, economic, and social benefits (water quality protection, clean air, flood protection, pollination, pest predation, wildlife habitat and diversity, recreational opportunities, etc.) that extend far beyond the boundaries of any individual forested area.

Large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, and provide more habitat for forest interior species. They are also more resistant to the spread of invasive species, suffer less tree damage from wind and ice storms, and provide more ecosystem services – from carbon storage to water filtration – than small patches,⁵³

Lands adjacent to well pads and infrastructure can also be affected, even if they are not directly cleared. This is most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on interior forest conditions.

Forest ecologists call this the edge effect. While the effect is somewhat different for each species, research has shown measurable impacts often extend at least 330 feet (100 meters) into forest adjacent to an edge.⁵⁴ Interior forest species avoid edges for different reasons. Black-throated blue warblers and other interior forest birds, for example, avoid areas near edges during nesting season because of the increased risk of predation. Tree frogs, flying squirrels and certain woodland flowers are sensitive to forest fragmentation because of changes in canopy cover, humidity and light levels. Some species, such as white-tailed deer and cowbirds, are attracted to forest edges – often resulting in increased competition, predation, parasitism, and herbivory.

⁵¹ NYSDEC, Forest Resource Assessment and Strategy, 2010.

⁵² NYSDEC, Forest Resource Assessment and Strategy, 2010.

⁵³ Johnson, 2010, p. 19.

⁵⁴ Johnson, 2010, p. 11.

Invasive plant species, such as tree of heaven, stilt grass, and Japanese barberry, often thrive on forest edges and can displace native forest species. As large forest patches become progressively cut into smaller patches, populations of forest interior species decline.

Lessons Learned from Pennsylvania

Assessment 1, General Discussion: The Nature Conservancy (TNC) conducted an assessment in 2010⁵⁵ to develop credible energy development projections for horizontal hydraulic fracturing in Pennsylvania's Marcellus Shale by 2030, and how those projections might affect high priority conservation areas, including forests. The projections were informed scenarios, not predictions, for how much energy development might take place and where it was more and less probable. Project impacts, however, were based on measurements of actual spatial footprints for hundreds of well pads.

Potential Direct Impacts, Methodology and Assessment Findings: Projections of future Marcellus gas development impacts depended on robust spatial measurements for existing Marcellus well pads and infrastructure. This assessment compared aerial photos of Pennsylvania Department of Environmental Protection (PADEP) Marcellus well permit locations taken before and after development and precisely documented the spatial foot print of 242 Marcellus well pads (totaling 435 drilling permits) in Pennsylvania.

Well pads in Pennsylvania occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad (Figure 6.5).⁵⁶

⁵⁵ Johnson, 2010.

⁵⁶ This is larger than the 7.4 acres predicted by IOGA to be disturbed in New York (section 6.4b).

Average Spatial Disturbance for Marcellus Shale Well Pads in Forested Context (acres)		
Forest cleared for Marcellus Shale well pad	3.1	8.8
Forest cleared for associated infrastructure (roads, pipelines, water impoundments, etc.)	5.7	
Indirect forest impact from new edges	21.2	
TOTAL DIRECT AND INDIRECT IMPACTS	30	

Figure 6.5 - Average Spatial Disturbance for Marcellus Shale Well Pads in Forested Context⁵⁷ (New July 2011)

Another key variable for determining land-use and habitat impacts in this assessment was the number of wells on each pad; more wells per pad translated to less disturbance and infrastructure on the landscape. It is technically possible to put a dozen or more Marcellus wells on one pad. For the 242 well pads assessed in this study, the average in Pennsylvania has been 2 wells per pad to date (IOGA estimates the same for New York) as companies quickly moved on to drill other leases to test productivity and to secure as many potentially productive leases as possible (leases typically expire after 5 years if there is no drilling activity). TNC assumed that in many cases, the gas company would return to these pads later and drill additional wells. This assumption may not be valid in New York where there is a three-year limit on well development (ECL 23-0501).

The TNC assessment developed low, medium, and high scenarios for the amount of energy development that might take place in Pennsylvania. The projections included a conservative

⁵⁷ Taken from Johnson, 2010, p. 10.

estimate of 250 horizontal drilling rigs, each of which could drill one well per month, resulting in an estimated 3,000 wells drilled annually. Estimates in New York predict less activity than this, but activity could result in approximately 40,000 wells by 2040.

The low scenario (6,000 well pads) assumed that each pad on average would have 10 wells, or 1 well pad per 620 acres. Because many leases are irregularly shaped, in mixed ownership, or their topography and geology impose constraints, TNC concluded that it is unlikely this scenario would develop in Pennsylvania. It would take relatively consolidated leaseholds and few logistical constraints for this scenario to occur.⁵⁸

The medium scenario for well pads assumed 6 wells on average would be drilled from each pad (10,000 well pads), or 1 pad per 386 acres. Industry generally agreed that 6 is the most likely number of wells they would be developing per pad for most of their leaseholds in Pennsylvania.⁵⁹

The high scenario assumed each pad would have 4 wells drilled on average (15,000 well pads), or 1 pad per 258 acres. This scenario is more likely if there is relatively little consolidation of lease holds between companies in the next several years. While this scenario would result in a loss of less than 1% of Pennsylvania's total forest acreage, areas with intensive Marcellus gas development could see a loss of 2-3% of local forest habitats.

In summary, 60,000 wells could be drilled by 2030 in the area underlain by the Marcellus Shale in Pennsylvania on between 6,000 and 15,000 new well pads (there are currently about 1,000), depending on how many wells are placed on each pad.

A majority (64%) of projected well locations were found in a forest setting for all three scenarios. By 2030, a range of between 34,000 and 82,000 acres of forest cover could be cleared by new Marcellus gas development in Pennsylvania. Some part of the cleared forest area would

⁵⁸ Note that while no definitive number is provided in section 5.1.3.2, this is expected to be the most common spacing for horizontal drilling in New York's Marcellus Shale.

⁵⁹ Note that IOGA assumes that 6 horizontal wells would be drilled per pad in New York.

become reforested after drilling is completed, but there has not been enough time to establish a trend since the Marcellus development started.

Potential Direct Impacts, Implications for New York: Direct land disturbance from horizontal hydraulic fracturing of Marcellus Shale in New York is expected to result in 7.4 acres of direct impacts from each well pad and associated infrastructure. This is different from the experiences in Pennsylvania where nearly 9 acres of habitat was removed for each well pad and its associated infrastructure. Under either scenario, the direct impacts are substantial.

The most likely drilling scenario in Pennsylvania would result in a density of 1 pad per 386 acres. However, given New York's regulatory structure, a spacing of 1 pad per 640 acres is anticipated. If spacing units are less than 640 acres, or if there are less than 6-8 horizontal wells per pad, the percentage of land disturbance could be greater. Again, using the set of currently pending applications as an example, the 47 proposed horizontal wells would be drilled on eleven separate well pads, with between 2 and 6 wells for each pad. Therefore, greater than 1.2% land disturbance per pad estimated by industry can be expected in New York.

Potential Indirect Impacts, Methodology and Assessment Findings: To assess the potential interior forest habitat impact, a 100-meter buffer was created into forest patches from new edges created by well pad and associated infrastructure development (Figure 6.6). For those well sites developed in forest areas or along forest edges (about half of the assessed sites), TNC calculated an average of 21 acres of interior forest habitat was lost. Thus, the total combined loss of habitat was 30 acres per well pad due to direct and indirect impacts (Figure 6.4 summarizes these data).

In addition to the direct clearing of between 34,000 to 82,000 acres of forest cover in Pennsylvania, forest interior species could be negatively impacted within an additional 85,000 to 190,000 forest acres adjacent to Marcellus development. Forest impacts would be concentrated where many of Pennsylvania's largest and most intact forest patches occur, resulting in fragmentation into smaller patches by well pads, roads, and other infrastructure. In contrast to overall forest loss, projected Marcellus gas development scenarios in Pennsylvania indicate a more pronounced impact on large forest patches. Impacts to forest interior species would vary depending on their geographic distribution and density. Some species, such as the black-throated

blue warbler, could see widespread impacts to their relatively restricted breeding habitats in the state, while widely distributed species such as the scarlet tanager, would be relatively less affected.

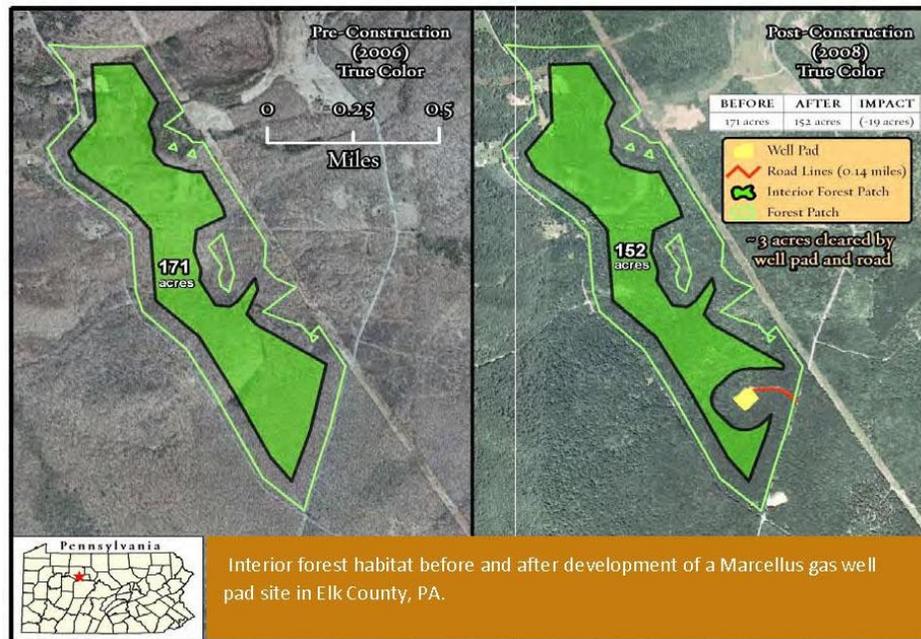


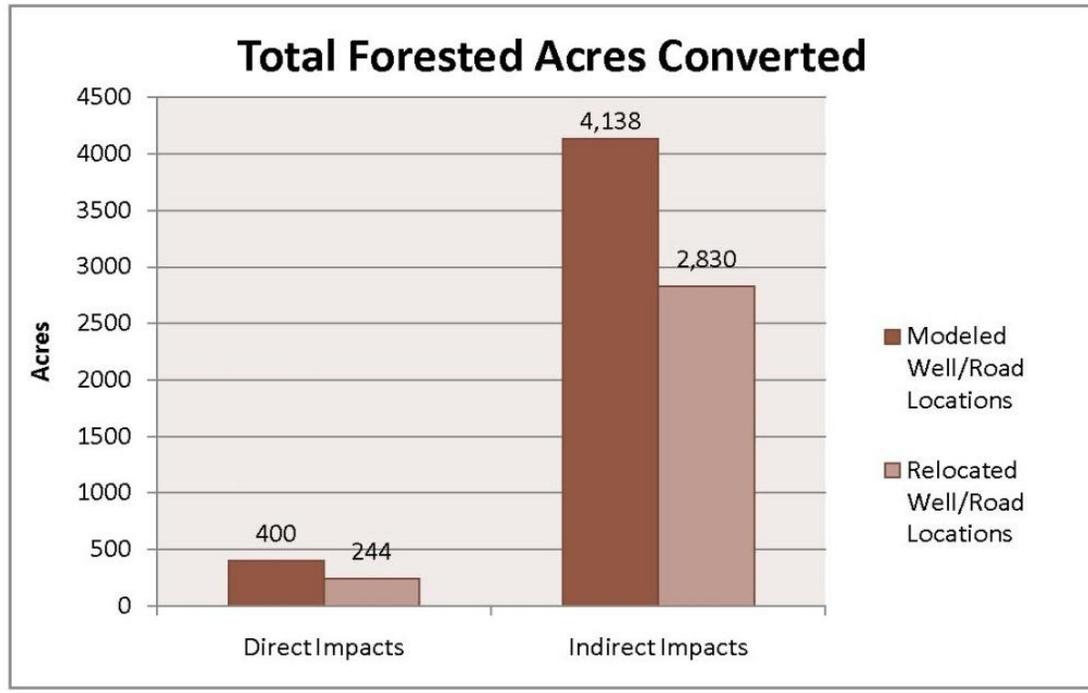
Figure 6.6 – Interior Forest Habitat Before & After Development of a Marcellus Gas Well Pad, Elk County PA⁶⁰ (New July 2011)

This study went on to find that locating energy infrastructure in open areas or toward the outer edges of large patches can significantly reduce impacts to important forest areas. To address this finding and explore potential ways in which conservation impacts could be minimized, TNC examined how projected Marcellus gas pads could be relocated to avoid forest patches in a specific region of Pennsylvania. To reduce the impacts to forest habitats, the wells were hypothetically relocated, where practicable, to nearby existing openings maintained by human activity (e.g., old fields, agricultural fields). If nearby open areas did not exist, the locations of the well pads were moved toward the edges of forest patches to minimize impacts to forest interior habitats. This exercise did not eliminate forest impacts in this heavily forested Pennsylvania landscape, but there was a significant reduction in impacts. Total forest loss

⁶⁰ Taken from Johnson, 2010, p. 11.

declined almost 40% while impacts to interior forest habitats adjacent to new clearings declined by one-third (Figure 6.7). The study authors recommend that information about Pennsylvania's important natural habitats be an important part of the calculus about trade-offs and optimization as energy development proceeds.

Figure 6.7 - Total Forest Areas Converted⁶¹ (New July 2011)



Potential Indirect Impacts, Implications for New York: For each acre of forest directly cleared for well pads and infrastructure in New York, an additional 2.5 acres can be expected to be indirectly impacted. Interior forest bird species with restricted breeding habitats, such as the black-throated blue and cerulean warblers, might be highly impacted.

Additional assessment work conducted for New York based on estimates and locations of well pad densities across the Marcellus landscape could better quantify expected impacts to forest interior habitats and wildlife.

⁶¹ Taken from Johnson, 2010, p. 27

New York Forest Matrix and Landscape Connectivity

Forest matrix blocks contain mature forests with old trees, understories, and soils that guarantee increased structural diversity and habitat important to many species. They include important stabilizing features such as large, decaying trunks on the forest floor and big, standing snags. Set within these matrix forests are smaller ecosystems offering a wide range of habitat (wetlands, streams, and riparian areas) that depend on the surrounding forested landscape for their long-term persistence and health. These large, contiguous areas are viable examples of the dominant forest types that, if protected, and in some cases allowed to regain their natural condition, serve as critical source areas for all species requiring interior forest conditions. Few remnants of such matrix blocks remain in the Northeast; it is therefore critical to conserve these priority areas to ensure long-term conservation of biodiversity.⁶²

Assessment 2, General Discussion: The New York Natural Heritage program in 2010⁶³
identified New York's forest matrix blocks and predicted corresponding forest connectivity areas. Securing connections between major forested landscapes and their imbedded matrix forest blocks is important for the maintenance of viable populations of species, especially those that are wide-ranging and highly mobile, and ecological processes such as dispersal and pollination over the long term. Identifying, maintaining, and enhancing these connections represents a critical adaptation strategy if species are to shift their ranges in response to climate change and other landscape changes.

Assessment 2, Findings. Figure 6.8 depicts the large forested landscapes within New York and predicts the linkages between them, called least-cost path (LCP). A least-cost path corridor represents the most favorable dispersal path for forest species based on a combination of percent natural forest cover in a defined area, barriers to movement, and distance traveled. Thus, as many species that live in forests generally prefer to travel through a landscape with less human development (i.e., fewer impediments to transit) as well as in a relatively direct line, the predicted routes depict a balance of these sometimes opposing needs.

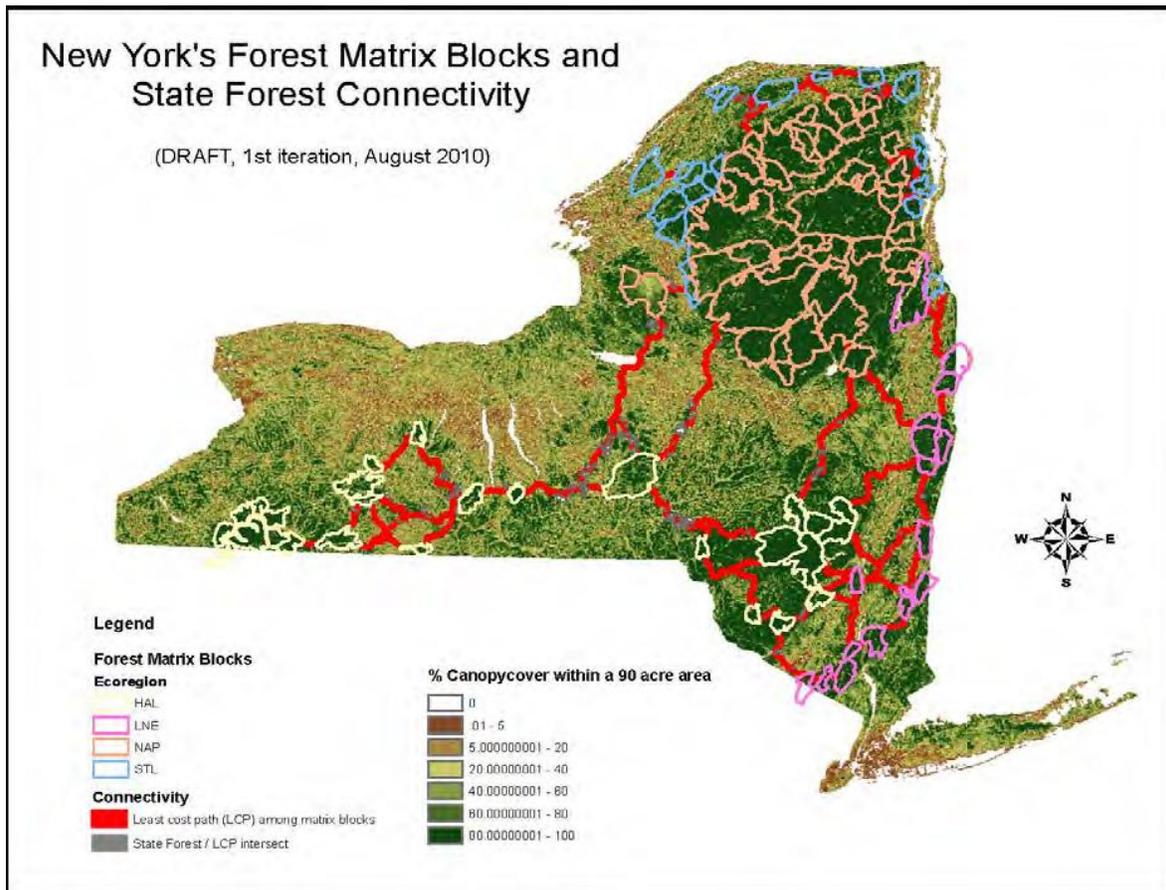
⁶² TNC 2004.

⁶³ NYSDEC, Strategic Plan for State Forest Management, 2010.

Assessment 2, Implications for New York: The area underlain by the Marcellus Shale in New York is 57% forested with about 7% of that forest cover occurring on State-owned lands. It is reasonable to assume high-volume horizontal hydraulic fracturing would have negative impacts to forest habitats similar to those predicted in Pennsylvania (Section 6.4.1.1.a).

In order to minimize habitat fragmentation and resulting restrictions to species movement in the area underlain by the Marcellus, it is recommended that forest matrix blocks be managed to create, maintain, and enhance the forest cover characteristics that are most beneficial to the priority species that may use them.

Figure 6.8 - New York's Forest Matrix Blocks and State Connectivity⁶⁴ (New July 2011)



HAL = High Allegheny Plateau; LNE = Lower New England/Northern Piedmont; NAP= Northern Appalachian/ Acadian; STL= St. Lawrence-Champlain Valley

⁶⁴ Taken from NYSDEC, Strategic Plan for State Forest Management, 2010.

6.4.2 *Invasive Species*

An invasive species, as defined by ECL §9-1703, is a species that is nonnative to the ecosystem under consideration and whose introduction causes or is likely to cause economic or environmental harm or harm to human health. Invasive species can be plants, animals, and other organisms such as microbes, and can impact both terrestrial and aquatic ecosystems.

While natural means such as water currents, weather patterns and migratory animals can transport invasive species, human actions - both intentional and accidental - are the primary means of invasive species introductions to new ecosystems. Once introduced, invasive species usually spread profusely because they often have no native predators or diseases to limit their reproduction and control their population size. As a result, invasive species out-compete native species that have these controls in place, thus diminishing biological diversity, altering natural community structure and, in some cases, changing ecosystem processes. These environmental impacts can further impose economic impacts as well, particularly in the water supply, agricultural and recreational sectors.⁶⁵

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.

6.4.2.1 *Terrestrial*

Terrestrial plant species which are widely recognized as invasive⁶⁶ or potentially-invasive in New York State, and are therefore of concern, are listed in Table 6.3 below.

⁶⁵ ECL §9-1701.

⁶⁶ As per ECL §9-1703.

Table 6.3 - Terrestrial Invasive Plant Species In New York State (Interim List)^{67,68}

Terrestrial - Herbaceous	
Common Name	Scientific Name
Garlic Mustard	<i>Alliaria petiolata</i>
Mugwort	<i>Artemisia vulgaris</i>
Brown Knapweed	<i>Centaurea jacea</i>
Black Knapweed	<i>Centaurea nigra</i>
Spotted Knapweed	<i>Centaurea stoebe</i> ssp. <i>micranthos</i>
Canada Thistle	<i>Cirsium arvense</i>
Bull Thistle	<i>Cirsium vulgare</i>
Crown vetch	<i>Coronilla varia</i>
Black swallow-wort	<i>Cynanchum louiseae</i> (<i>nigrum</i>)
European Swallow-wort	<i>Cynanchum rossicum</i>
Fuller's Teasel	<i>Dipsacus fullonum</i>
Cutleaf Teasel	<i>Dipsacus laciniatus</i>
Giant Hogweed	<i>Heracleum mantegazzianum</i>
Japanese Stilt Grass	<i>Microstegium vimineum</i>
Terrestrial - Vines	
Common Name	Scientific Name
Porcelain Berry	<i>Ampelopsis brevipedunculata</i>
Oriental Bittersweet	<i>Celastrus orbiculatus</i>
Japanese Honeysuckle	<i>Lonicera japonica</i>
Mile-a-minute Weed	<i>Persicaria perfoliata</i>
Kudzu	<i>Pueraria montana</i> var. <i>lobata</i>
Terrestrial - Shrubs & Trees	
Common Name	Scientific Name
Norway Maple	<i>Acer platanoides</i>
Tree of Heaven	<i>Ailanthus altissima</i>
Japanese Barberry	<i>Berberis thunbergii</i>

⁶⁷ NYSDEC, DFWMR March 13, 2009. Interim List of Invasive Plant Species in New York State

⁶⁸ This list was prepared pursuant to ECL §9-1705(5)(b) and ECL §9-1709(2)(d), but is not the so-called “four-Tier lists” referenced in ECL §9-1705(5)(h). As such the interim list is expected to be supplanted by the “four-Tier list” at such time that it becomes available.

Terrestrial - Herbaceous	
Common Name	Scientific Name
Russian Olive	<i>Elaeagnus angustifolia</i>
Autumn Olive	<i>Elaeagnus umbellata</i>
Glossy Buckthorn	<i>Frangula alnus</i>
Border Privet	<i>Ligustrum obtusifolium</i>
Amur Honeysuckle	<i>Lonicera maackii</i>
Shrub Honeysuckles	<i>Lonicera morrowii/tatarica/x bella</i>
Bradford Pear	<i>Pyrus calleryana</i>
Common Buckthorn	<i>Rhamnus cathartica</i>
Black Locust	<i>Robinia pseudoacacia</i>
Multiflora Rose	<i>Rosa multiflora</i>

Operations involving land disturbance such as the construction of well pads, access roads, and engineered surface impoundments for fresh water storage have the potential to both introduce and transfer invasive species populations. Machinery and equipment used to remove vegetation and soil may come in contact with invasive plant species that exist at the site and may inadvertently transfer those species' seeds, roots, or other viable plant parts via tires, treads/tracks, buckets, etc. to another location on site, to a separate project site, or to any location in between.

The top soil that is stripped from the surface of the site during construction and set aside for re-use during reclamation also presents an opportunity for the establishment of an invasive species population if it is left exposed. Additionally, fill sources (e.g., gravel, crushed stone) brought to the well site for construction purposes also have the potential to act as a pathway for invasive species transfer if the fill source itself contains viable plant parts, seeds, or roots.

6.4.2.2 Aquatic

The presence of non-indigenous aquatic invasive species in New York State waters is recognized, and, therefore, operations associated with the withdrawal, transport, and use of water for horizontal well drilling and high volume hydraulic fracturing operations have the potential to transfer invasive species. Species of concern include, but are not necessarily limited to; zebra mussels, eurasian watermilfoil, alewife, water chestnut, fanwort, curly-leaf pondweed, round

goby, white perch, didymo, and the spiny water flea. Other aquatic, wetland and littoral plant species that are of concern due to their status as invasive⁶⁹ or potentially-invasive in New York State are listed in Table 6.4.

Table 6.4 - Aquatic, Wetland & Littoral Invasive Plant Species in New York State (Interim List)^{70,71}

Floating & Submerged Aquatic	
Common Name	Scientific Name
Carolina Fanwort	<i>Cabomba caroliniana</i>
Rock Snot (didymo)	<i>Didymosphenia geminata</i>
Brazilian Elodea	<i>Egeria densa</i>
Water thyme	<i>Hydrilla verticillata</i>
European Frog's Bit	<i>Hydrocharis morus-ranae</i>
Floating Water Primrose	<i>Ludwigia peploides</i>
Parrot-feather	<i>Myriophyllum aquaticum</i>
Variable Watermilfoil	<i>Myriophyllum heterophyllum</i>
Eurasian Watermilfoil	<i>Myriophyllum spicatum</i>
Brittle Naiad	<i>Najas minor</i>
Starry Stonewort (green alga)	<i>Nitellopsis obtusa</i>
Yellow Floating Heart	<i>Nymphoides peltata</i>
Water-lettuce	<i>Pistia stratiotes</i>
Curly-leaf Pondweed	<i>Potamogeton crispus</i>
Water Chestnut	<i>Trapa natans</i>
Emergent Wetland & Littoral	
Common Name	Scientific Name
Flowering Rush	<i>Butomus umbellatus</i>
Japanese Knotweed	<i>Fallopia japonica</i>
Giant Knotweed	<i>Fallopia sachalinensis</i>
Yellow Iris	<i>Iris pseudacorus</i>
Purple Loosestrife	<i>Lythrum salicaria</i>
Reed Canarygrass	<i>Phalaris arundinacea</i>
Common Reed- nonnative variety	<i>Phragmites australis</i> var. <i>australis</i>

⁶⁹ As per ECL §9-1703.

⁷⁰ NYSDEC, DRWMR March 13, 2009 Interim List of Invasive Plant Species in New York State

⁷¹ This list was prepared pursuant to ECL §9-1705(5)(b) and ECL §9-1709(2)(d) , but is not the so-called “four-Tier lists” referenced in ECL §9-1705(5)(h). As such the interim list is expected to be supplanted by the “four-Tier list” at such time that it becomes available.

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

6.4.3 Impacts to Endangered and Threatened 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 (Table 6.5 and Figure 6.8) protected under the State Endangered Species Law (ECL 11-0535) and associated regulations (6 NYCRR Part 182). Some species, such as the northern harrier and upland sandpiper, are dependent upon grassland habitat for breeding and foraging and can be found in many counties within the project area. Species such as the rayed bean mussel and mooneye fish are aquatic species limited to only two counties on the western edge of the project area. Other species are associated with woodlands, with bald eagles nesting in woodlands adjacent to lakes, rivers and ponds throughout many counties within the project area. The area also includes habitat for cerulean warblers and eastern hellbenders, two species currently under consideration for listing by both the State and the federal government.

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. If these actions occur during the time of year that species are breeding, there can be a direct loss of eggs and/or young. For species that are limited to specific habitat types for breeding, the loss of the breeding area can result in a loss of productivity in future years as adults are forced into less suitable habitat. Any road construction through streams or wetlands within habitats occupied by these species can result in the creation of impermeable barriers to movement for aquatic species and reduce dispersal for some terrestrial species. Other impacts from the project, such as increased vehicle traffic, can result in direct mortality of adult animals. In general, the loss of habitat in areas

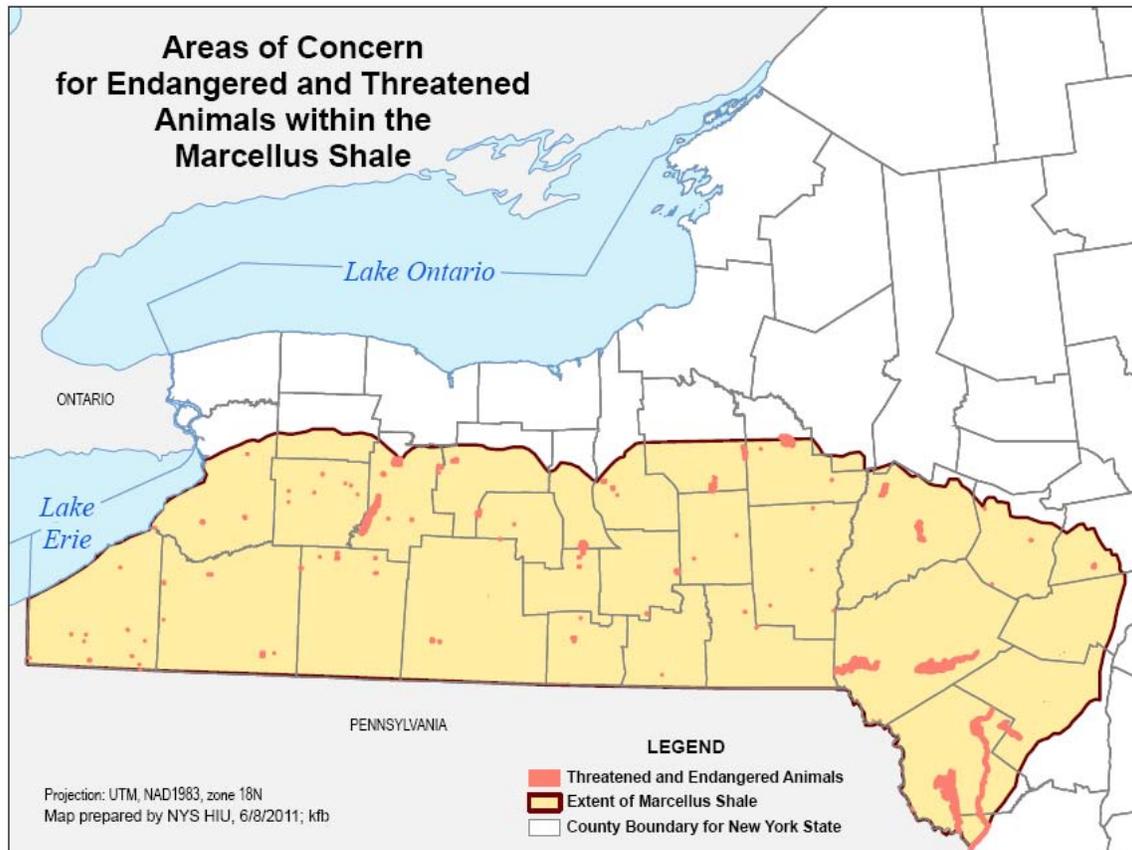
occupied by listed species can result in reduced numbers of breeding pairs and lowered productivity.

Table 6.5 - Endangered & Threatened Animal Species within the Area Underlain by the Marcellus Shale ⁷²(New July 2011)

Common Name	Scientific name	NYS Listing	Primary Habitats
Henslow's Sparrow	<i>Ammodramus henslowii</i>	Threatened	Grassland
Short-eared Owl	<i>Asio flammeus</i>	Endangered	Grassland
Upland Sandpiper	<i>Bartramia longicauda</i>	Threatened	Grassland
Northern Harrier	<i>Circus cyaneus</i>	Threatened	Grassland, wetlands
Sedge Wren	<i>Cistothorus platensis</i>	Threatened	Grassland
Peregrine Falcon	<i>Falco peregrinus</i>	Endangered	Cliff faces
Bald Eagle	<i>Haliaeetus leucocephalus</i>	Threatened	Forest, open water
Least Bittern	<i>Ixobrychus exilis</i>	Threatened	Wetlands
Pie-billed Grebe	<i>Podilymbus podiceps</i>	Threatened	Wetlands
Eastern Sand Darter	<i>Ammocrypta pellucida</i>	Threatened	Streams
Mooneye	<i>Hiodon tergisus</i>	Endangered	Large Lakes, Rivers
Longhead Darter	<i>Percina macrocephala</i>	Threatened	Large Streams, Rivers
Brook Floater	<i>Alasmidonta varicosa</i>	Threatened	Streams and Rivers
Wavyrayed Lampmussel	<i>Lampsilis fasciola</i>	Threatened	Small, Medium Streams
Green Floater	<i>Lasmigona subviridis</i>	Threatened	Small, Medium Streams
Clubshell	<i>Pleurobema clava</i>	Endangered	Small, Medium Streams
Rayed Bean	<i>Villosa fabalis</i>	Endangered	Small Streams
Timber rattlesnake	<i>Crotalus horridus</i>	Threatened	Forest

⁷² November 3, 2010

Figure 6.9-Areas of Concern for Endangered and Threatened Animal Species within the Area Underlain by the Marcellus Shale in New York, March 31, 2011 (New July 2011)



6.4.4 Impacts to State-Owned Lands

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. They represent the most significant portions of large contiguous forest patch in the study area. Industrial development on these lands is, for the most part, prohibited, and any type of clearing and development on these lands is limited and managed. Given the level of development expected for multi-pad horizontal drilling, it is anticipated that there would be additional pressure for surface disturbance on state-owned lands. Surface disturbance associated with gas extraction

could have a significant adverse impact on habitats contained on the state-owned lands, and recreational use of those lands.

Forest Habitat Fragmentation

As described earlier, large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, and provide more habitat for forest interior species. State-owned lands, by their very nature, consist of large contiguous forest patches. While some fragmentation has occurred, the level of activity associated with multi-well horizontal drilling (e.g., well pad construction, access roads, pipelines, etc.) would negatively impact the state's ability to maintain the existing large contiguous patches of forest.

The Department has stated that protecting these areas from further fragmentation is a high priority. One of the objectives stated in the Strategic Plan for State Forest Management is to "emphasize closed canopy and interior forest conditions to maintain and enhance" forest matrix blocks. It is critical therefore, that any additional road, pipeline and well pad construction be carefully assessed in order to avoid further reducing this habitat (see also Section 6.4.1). Given the State's responsibility to protect these lands as steward of the public trust, the State has a heightened responsibility, as compared to its role with respect to private lands, to ensure that any State permitted action does not adversely impact the ecosystems and habitat on these public lands so that they may be enjoyed by future generations.

Public Recreation

State-owned lands have been acquired over the past century to provide compatible public recreation opportunities, protect watersheds, and provide sustainable timber harvesting. Drilling and trucking activities disturb the tranquility found on these lands and can cause significant visual impacts. Also, many State Forest roads serve as recreational trails for bicyclists, horseback riders, snowmobilers and others. The level of truck traffic associated with horizontal drilling and high-volume hydraulic fracturing presents safety issues, and would significantly degrade the experience for users of these roads, if not altogether during the drilling and construction phases of development.

Legal Considerations

State Forests have an identity that is distinct from private lands, prescribed by the NYS Constitution, the ECL and the Environmental Quality Bond Acts of 1972 and 1986, under the provisions of which they were acquired. New York State Constitution Article XIV, Section 3(1) states:

“Forest and wild life conservation are hereby declared to be policies of the state. For the purposes of carrying out such policies the legislature may appropriate moneys for the acquisition by the state of land, outside of the Adirondack and Catskill parks as now fixed by law, for the practice of forest or wild life conservation.”

ECL Section 9-0501(1), in keeping with the above constitutional provision, authorizes the state to acquire reforestation areas, “which are adapted for reforestation and the establishment and maintenance thereon of forests for watershed protection, the production of timber and other forests products, and for recreation and kindred purposes,. . .which shall be forever devoted to the planting, growth and harvesting of such trees...”

Similarly, ECL Section 11-2103(1) authorizes the state to acquire “lands, waters or lands and waters...for the purpose of establishing and maintaining public hunting, trapping and fishing grounds.”

ECL Section 9-0507 provides the Department discretionary authority to lease oil and gas rights on reforestation areas, provided that “such leasehold rights shall not interfere with the operation of such reforestation areas for the purposes for which they were acquired and as defined in Section 3 of Article XIV of the Constitution.” The expected volume of truck traffic, the expected acreage that would be converted to non-forest use in the form of well pads, roads and pipelines, and noise and other impacts, raise serious questions as to how the surface activities anticipated with horizontal drilling and high-volume hydraulic fracturing could be viewed as consistent with this provision of the ECL.

For Wildlife Management Areas (WMAs) there are additional legal considerations stemming from the use of federal funds. Many WMAs were purchased using Federal Aid in Wildlife Restoration (Pittman-Robertson) funds and all are managed/maintained using Pittman-Robertson

funds. Under these provisions, any surface use of the land must not be in conflict with the intended use as a WMA. These areas are managed for natural habitats to benefit wildlife, and disturbance associated with multi-pad wells raises questions about compatibility with essential wildlife behaviors such as breeding, raising young, and preparation for migration. Also, selling or leasing of minerals rights must be approved by the U.S. Fish and Wildlife Service, and may require reimbursement of the federal government for revenue generated. In addition, siting well pads on WMAs purchased with Conservation Fund monies may require additional mitigation under federal statutes and/or compensation.

6.5 Air Quality

6.5.1 Regulatory Overview

This section provides a comprehensive list of federal and New York State regulations which could potentially be applicable to air emissions and air quality impacts associated with the drilling, completion (hydraulic fracturing and flowback) and production phases (processing, transmission and storage). At each of these phases, there are a number of air emission sources that may be subject to regulation. These general regulatory requirements are then followed by specific information regarding emission sources that have potential regulatory implications, as presented below in Sections 6.5.1.1 to 6.5.1.8. Certain discussions reflect new industry information provided in response to Department requests, as well as finalization, clarification, and revision to EPA regulations and policy. For example, the definition of what constitutes a stationary source or “facility” has been refined for criteria pollutants. These discussions are then followed with Department rule-applicability determinations on in instances where such decisions can be made as part of the SGEIS, as well as how the Department envisions the permitting of specific operations should proceed (Section 6.5.1.9).

Applicable Federal Regulations

Prevention of Significant Deterioration of Air Quality (PSD): Under the PSD program, a federally-enforceable permit is required in order to restrict emissions from new major or major modification to existing sources (e.g., power plants and manufacturing facilities which emit criteria air pollutants in quantities above 100 tons per year) located in areas classified as attainment or unclassifiable with respect to the National Ambient Air Quality Standards (NAAQS). That is, PSD requirements apply to all pollutants that do not exceed the NAAQS in

the source location area. The NAAQS are numerical maximum pollution levels set to protect public health and welfare which have been established for ozone (O₃), nitrogen dioxide (NO₂), sulfur dioxide (SO₂), fine particulate matter (PM₁₀ and PM_{2.5}), carbon monoxide (CO) and lead. The federal PSD program is contained in 40 CFR Section 52.21 and the federally approved State program is found at 6 NYCRR Part 231.

Nonattainment New Source Review (NNSR): This federal program applies to new major or modified existing major sources in areas where the NAAQS are exceeded. The requirements for source emissions and potential impacts are more restrictive than through the PSD program. The federal program is found at 40 CFR Section 51.165 and the federally approved State program is found at 6 NYCRR Part 231. In New York State, nonattainment requirements are currently applicable to major sources of O₃ precursors (NO_x and VOC) and direct PM_{2.5} and its precursor emissions (SO₂ and NO_x). EPA has approved 6 NYCRR Part 231 into the State Implementation Plan. The regulation is described further under “Applicable State Regulations” below.

New Source Performance Standards (NSPS): Section 111 of the Clean Air Act (CAA) requires EPA to adopt emissions standards that are applicable to new, modified, and reconstructed sources. The requirements are meant to force new facilities to perform as well as or better than the best existing facilities (commonly known as “best demonstrated technology”). As new technology advances are made, EPA is required to revise and update NSPS applicable to designated sources. The following federal NSPS may apply:

- 40 CFR Part 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE). Subpart JJJJ applies to manufacturers, owners and operators of SI ICE which affects new, modified, and reconstructed stationary SI ICE (i.e., generators, pumps and compressors), combusting any fuel (i.e., gasoline, natural gas, LPG, landfill gas, digester gas etc.), except combustion turbines. The applicable emissions standards are based on engine type, fuel type, and manufacturing date. The regulated pollutants are NO_x, CO and VOC and there is a sulfur limit on gasoline. Subpart JJJJ would apply to facilities operating spark ignition engines at compressor stations;
- 40 CFR Part 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition (CI) ICEs. Subpart IIII applies to manufacturers, owners and operators of CI ICE (diesel) which affects new, modified, and reconstructed (commencing after July 11,

2005) stationary CI ICE (i.e., generators, pumps and compressors), except combustion turbines. The applicable emissions standards (phased in Tiers with increasing levels of stringency) are based on engine type and model year. The regulated pollutants are NO_x, PM, CO, non-methane hydrocarbons (NMHC), while the emissions of sulfur oxides (SO_x) are reduced through the use of low sulfur fuel. Particulate emissions are also reduced by standards. Subpart IIII would apply to facilities operating compression ignition engines at compressor stations;

- 40 CFR Part 60, Subpart KKK - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. Subpart KKK applies to gas processing plants that are engaged in the extraction of natural gas liquids from field gas and contains provisions for VOC leak detection and repair (LDAR);
- 40 CFR Part 60, Subpart LLL - Standards of Performance for Onshore Natural Gas Processing: SO₂ Emissions. Subpart LLL governs emissions of SO₂ from gas processing plants, specifically gas sweetening units (remove H₂S and CO₂ from sour gas) and sulfur recovery units (recover elemental sulfur); and
- 40 CFR Part 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

National Emission Standards for Hazardous Air Pollutants (NESHAPs): Section 112 of the CAA requires EPA to adopt standards to control emissions of hazardous air pollutants (HAPs). NESHAPs are applicable to both new and existing sources of HAPs, and there are NESHAPs for both “major” sources of HAPs and “area” sources of HAPs. A major source of HAPs is one with the potential to emit in excess of 10 Tpy of any single HAP or 25 Tpy of all HAPs, combined. An area source of HAPs is a stationary source of HAPs that is not major. The aim is to develop technology-based standards which require levels met by the best existing facilities. The pollutants of concern in the oil and gas sector primarily are the following: BTEX, formaldehyde, and n-hexane. The following federal NESHAPs may apply:

- 40 CFR Part 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE). Appendix 17 has been revised from the initial analysis to reflect the requirements in the final EPA rule;

- 40 CFR Part 63, Subpart H - National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks. Subpart H applies to equipment that contacts fluids with a HAP concentration of 5%;
- 40 CFR Part 63, Subpart HH - NESHAPs from Oil and Natural Gas Production Facilities. Subpart HH controls air toxics from oil and natural gas production operations and contains provisions for both major sources and area sources of HAPs. Emission sources affected by this regulation are tanks with flash emissions (major sources only), equipment leaks (major sources only), and glycol dehydrators (major and area sources). Further details on this subpart are presented in section 6.5.1.2;
- 40 CFR Part 63, Subpart HHH - NESHAPs from Natural Gas Transmission and Storage Facilities. Subpart HHH controls air toxics from natural gas transmission and storage operations. It affects glycol dehydrators located at major sources of HAPs; and
- 40 CFR Part 61, Subpart V - National Emission Standard for Equipment Leaks (Fugitive Emission Sources). Subpart V applies to equipment that contacts fluids with a volatile HAP concentration of 10%.

Applicable New York State Regulations

New York State Air Regulations are codified at 6 NYCRR Part 200 *et seq.*, and can be obtained from the Department's web site at www.dec.ny.gov/regs/2492.html. Some of the applicable regulations are briefly described below.

- Part 200 - General Provisions;
 - Section 200.1 Definitions (relevant subsections);
 - (cd) Stationary source. Any building, structure, facility or installation, excluding nonroad engines, that emits or may emit any air pollutant;
 - (aw) Nonroad engine. (1) Except as specified in paragraph (2) of this subdivision, a nonroad engine is an internal combustion engine:
 - (iii) that, by itself or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Indicators of transportability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform.
 - (2) An internal combustion engine is not a nonroad engine if:

(iii) the engine otherwise included in subparagraph (1)(iii) of this subdivision remains or would remain at a location for more than 12 consecutive months or a shorter period of time for an engine located at a seasonal source. A location is any single site at a building, structure, facility, or installation. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine replaced would be included in calculating the consecutive time period. An engine located at a seasonal source is an engine that remains at a seasonal source during the full annual operating period of the seasonal source. A seasonal source is a stationary source that remains in a single location on a permanent basis (i.e. at least two years) and that operates at that single location approximately three months (or more) each year. This paragraph does not apply to an engine after the engine is removed from the location;

- Section 200.6 - Acceptable Ambient Air Quality. Section 200.6 states, “notwithstanding the provisions of this Subchapter, no person shall allow or permit any air contamination source to emit air contaminants in quantities which alone or in combination with emissions from other air contamination sources would contravene any applicable ambient air quality standard and/or cause air pollution. In such cases where contravention occurs or may occur, the commissioner shall specify the degree and/or method of emission control required”. This regulation prohibiting air pollution, allowing the Department to evaluate ambient impacts from emission sources; and
- Section 200.7 - Maintenance of Equipment. Section 200.7 states, “any person who owns or operates an air contamination source which is equipped with an emission control device shall operate such device and keep it in a satisfactory state of maintenance and repair in accordance with ordinary and necessary practices, standards and procedures, inclusive of manufacturer’s specifications, required to operate such device effectively.

- Part 201 - Permits and Registrations;

- 201-2.1 Definitions.
 - (21) Major stationary source or major source or major facility (see further details and discussions below);
- 201-5 - State Facility Permits. Subpart 201-5 contains the criteria to issue “state facility permits” to facilities that are not considered to be major. These are generally facilities with the following characteristics: (1) Their actual emissions exceed 50% of the level that would make them major, but their potential to emit

as defined in 6 NYCRR Part 200 does not place them in the major category, (2) They require the use of permit conditions to limit emissions below thresholds that would make them subject to certain state or federal requirements, or (3) They have been granted variances under the Department's air regulations;

- 201-6 - Title V Facility Permits. Subpart 201-6 contains the requirements and procedures for CAA "Title V Permits". These include facilities that are judged to be major under the Department's regulations, or that are subject to NSPSs, to a standard or other requirements regulating HAPs or to federal acid rain program requirements; and
- 201-7 - Federally Enforceable Emission Caps. Subpart 201-7 provides the ability to accept federally enforceable permit terms and conditions which restrict or cap emissions from a stationary source or emission unit in order to avoid being subject to one or more applicable requirements.
- Part 212 - General Process Emission Sources. In general, Part 212 regulates emissions of particulate, opacity, VOCs (from major sources), NO_x (from major sources) and is mainly used to control air toxics from industries not regulated in other specific 6 NYCRR Parts;
- Part 227- Stationary Combustion Installations (see Appendix 16 for more details):
 - 227-1- Stationary Combustion Installations. Subpart 227-1 regulates emissions from stationary combustion installations.
 - 227-2 - Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NO_x). Subpart 227-2 imposes NO_x limits on major sources (with a potential to emit 100 tons of NO_x per year) located in the attainment areas of the northeast ozone transport region;
- Part 229 - Petroleum and Volatile Organic Liquid Storage and Transfer. Part 229 regulates petroleum and volatile organic liquid storage and transfer (i.e., gasoline bulk plants, gasoline loading terminals, marine loading vessels, petroleum liquid storage tanks or volatile organic liquid storage tanks); and
- Part 231- New Source Review (NSR) for New and Modified Facilities. Part 231 addresses both the federal NSR and PSD requirements for sources located in nonattainment or attainment areas and the relevant program requirements. For new major facilities or modification of existing major facilities, Part 231 applies to those NSR pollutants with proposed emissions increases greater than the major facility or significant

project threshold, as applicable. The applicable PSD major facility threshold (100 or 250 tons per year) is determined by whether the facility belongs to one of the source categories listed in 6 NYCRR §201-2.1(b)(21)(iii). Reciprocating internal combustion engines are not on the list, making the major source threshold 250 tons per year (instead of 100 tons/year) for PSD applicable pollutants. For the nonattainment pollutants, the threshold levels are lower, and depend on the location of the proposed new facility or modification. For the Marcellus Shale area, which is located within the Ozone Transport Region (OTR), for regulatory purposes, the area is treated as moderate ozone nonattainment. The major facility thresholds are 50 tons per year for VOC and 100 tons per year for NO_x.

The following sections discuss what regulatory determinations the Department has made with respect to operations associated with drilling and completion activities and how the regulatory process would be used for further permitting determinations related to the offsite compressor stations and its association with the well pad operations.

6.5.1.1 Emission Analysis NO_x - Internal Combustion Engine Emissions

Compressor Engine Exhausts

Internal combustion engines provide the power to run compressors that assist in the production of natural gas from wells and pressurize natural gas from wells to the pressure of lateral lines that move natural gas in large pipelines to and from processing plants and through the interstate pipeline network. The engines are often fired with raw or processed natural gas, and the combustion of the natural gas in these engines results in air emissions.

Well Drilling and Hydraulic Fracturing Operations

Oil and gas drilling rigs require substantial power to drill and case wellbores to their target formations. For the development of the Marcellus Shale, this power would typically be provided by transportable diesel engines, which generate exhaust from the burning of diesel fuel. After the wellbore is drilled to the target formation, additional power is needed to operate the pumps that move large quantities of water, sand, or chemicals into the target formation at high pressure to hydraulically fracture the shale.

The preferred method for calculating engine emissions is to use emission factors provided by the engine manufacturer. If these cannot be obtained, a preliminary emissions estimate can be made using EPA AP-42 emission factors. The most commonly used tables appear as Table 6.6 below.

Table 6.6 - EPA AP-42 Emissions Factors Tables

EPA AP-42 Table 3.2-1: Emission Factors for Uncontrolled Natural Gas-Fired Engines						
Pollutant	2-cycle lean burn		4-cycle lean burn		4-cycle rich burn	
	g/Hp-hr (power input)	lb/MMBtu (fuel input)	g/Hp-hr (power input)	lb/MMBtu (fuel input)	g/Hp-hr (power input)	lb/MMBtu (fuel input)
NO _x	10.9	2.7	11.8	3.2	10.0	2.3
CO	1.5	0.38	1.6	0.42	8.6	1.6
TOC ¹	5.9	1.5	5.0	1.3	1.2	0.27

TOC is total organic compounds (sometimes referred to as THC). To determine VOC emissions calculate TOC emissions and multiply the value by the VOC weight fraction of the fuel gas.

EPA AP-42 Table 3.3-1: Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines				
Pollutant	Gasoline Fuel		Diesel Fuel	
	g/Hp-hr (power output)	lb/MMBtu (fuel input)	g/Hp-hr (power output)	lb/MMBtu (fuel input)
NO _x	5.0	1.63	14.1	4.41
CO	3.16	0.99	3.03	0.95
Exhaust (TOC)	6.8	2.10	1.12	0.35
Evaporative (TOC)	0.30	0.09	0.00	0.00
Crankcase (TOC)	2.2	0.69	0.02	0.01
Refueling (TOC)	0.5	0.15	0.00	0.00

Engine Emissions Example Calculations

A characterization of the significant NO_x emission sources during the three operational phases of horizontally drilled, hydraulically fractured natural gas wells is as follows:

1. Horizontally Drilled/ High-Volume Hydraulically Fractured Wells - Drilling Phase

For a diesel engine drive total of 5400 Hp drilling rig power,⁷³ using NO_x emission factor data from engine specification data received from natural gas production companies currently operating in the Marcellus Shale formation outside New York State, a representative NO_x emission factor of 6.4 g/Hp-hr is used in this example. For purposes of estimating the Potential

⁷³ Engine information provided by Chesapeake Energy

to Emit (PTE) for the engines, continuous year-round operation is assumed. The estimated NO_x emission would be:

$$\text{NO}_x \text{ emissions} = (6.4 \text{ g/Hp-hr}) \times (5400 \text{ Hp}) \times (8760 \text{ hr/yr}) \times (\text{ton}/2000 \text{ lb}) \times (1 \text{ lb}/453.6 \text{ g}) = 333.7 \text{ Tpy}$$

The actual emissions from the engines would be much lower than the above PTE estimate, depending on the number of wells drilled and the time it takes to drill the wells at a well site in a given year.

2. Horizontally Drilled/High-Volume Hydraulically Fractured Wells - Completion Phase

For diesel-drive 2333 Hp fracturing pump engine(s),⁷⁴ using NO_x emission factor data from engine specification data received from natural gas production companies currently operating in the Marcellus Shale formation outside New York State, a representative NO_x emission factor of 6.4 g/Hp-hr is used in this example. For purposes of estimating the Potential to Emit (PTE) for the engines, continuous year-round operation is assumed. The estimated NO_x emission would be:

$$\text{NO}_x \text{ emissions} = (6.4 \text{ g/Hp-hr}) \times (2333 \text{ Hp}) \times (8760 \text{ hr/yr}) \times (\text{ton}/2000 \text{ lb}) \times (1 \text{ lb}/453.6 \text{ g}) = 144.1 \text{ Tpy}$$

The actual emissions from the engines would be lower than the above PTE estimate, depending on the time it takes to hydraulically fracture each well and the number of wells hydraulically fractured at a well site in a given year.

3. Horizontally Drilled/High-Volume Hydraulically Fractured Wells - Production Phase

Using recent permit application information from a natural gas compressor station in the Department's Region 8, a NO_x emission factor 2.0 g/Hp-hr was chosen as more reasonable (yet still conservative) than AP-42 emission data. The maximum site-rated horsepower is 2500 Hp.⁷⁵ The engine(s) is expected to run year round (8760 hr/yr).

$$\text{NO}_x \text{ emissions} = (2.0 \text{ g/Hp-hr}) \times (2500 \text{ Hp}) \times (8760 \text{ hr/yr}) \times (\text{ton}/2000 \text{ lb}) \times (1 \text{ lb}/453.6 \text{ g}) = 48.3 \text{ TPY}$$

⁷⁴ Engine information provided by Chesapeake Energy.

⁷⁵ Engine information provided by Chesapeake Energy.

Since the engines in the example comply with the NO_x RACT emission limits, non-applicability of the rule implies merely avoiding the monitoring requirements that were designed for permanently located engines. In addition to NO_x RACT requirements, Title V permitting requirements could also apply to other air pollutants such as CO, SO₂, particulate matter (PM), ozone (as VOCs), and elemental lead, with the same emission thresholds as for NO_x. An initial review of other emission information for these engines, such as CO and PM emission factor data, reveals an unlikely possibility of reaching major source thresholds triggering Title V permitting requirements for these facilities as discussed further in Section 6.5.1.9.

6.5.1.2 Natural Gas Production Facilities NESHAP 40 CFR Part 63, Subpart HH (Glycol Dehydrators)

Natural gas produced from wells is a mixture of a large number of gases and vapors. Wellhead natural gas is often delivered to processing plants where higher molecular weight hydrocarbons, water, nitrogen, and other compounds are largely removed if they are present. Processing results in a gas stream that is enriched in methane at concentrations of usually more than 80%. Not all natural gas requires processing, and gas that is already low in higher hydrocarbons, water, and other compounds can bypass processing.

Processing plants typically include one or more glycol dehydrators, process units that dry the natural gas. Glycol, usually TEG, is used in dehydration units to absorb water from wet produced gas. “Lean” TEG contacts the wet gas and absorbs water. The TEG is then considered “rich.” As the rich TEG is passed through a flash separator and/or reboiler for regeneration, steam containing hydrocarbon vapors is released from it. The vapors are then vented from the dehydration unit flash separator and/or reboiler still vent.

Dehydration units with a natural gas throughput below 3 MMscf per day or benzene emissions below 1 Tpy are exempted from the control, monitoring and recordkeeping requirements of Subpart HH. Although the natural gas throughput of some Marcellus horizontal shale wells in New York State could conceivably be above 3 MMscf, preliminary analysis of gas produced at Marcellus horizontal shale gas well sites in Pennsylvania indicates a benzene-content below the exemption threshold of 1 Tpy, for the anticipated range of annual gas production for wells in the Marcellus. However, the affected natural gas production facilities would still likely be required

to maintain records of the exemption determination as outlined in 40 CFR §63.774(d) (1) (ii). Sources with a throughput of 3 MMscf/day or greater and benzene emissions of 1.0 Tpy or greater are subject to the rule's emission reduction requirements. This does not necessarily mean control, depending on the location of the affected emission sources relative to "urbanized areas (UA) plus offset" or to "urban clusters (UC) with a population of 10,000 or greater" as defined in the rule.

6.5.1.3 Flaring Versus Venting of Wellsite Air Emissions

Well completion activities include hydraulic fracturing of the well and a flowback period to clean the well of flowback water and any excess sand (fracturing proppant) that may return out of the well. Flowback water is routed through separation equipment to separate water, gas, and sand. Initially, only a small amount of gas is vented for a period of time. Once the flow rate of gas is sufficient to sustain combustion in a flare, the gas is flared for a short period of time for testing purposes. Recovering the gas to a sales gas line is called a reduced emissions completion (REC). See Section 6.6.8 for further discussion of RECs.

Normally the flowback gas is flared when there is insufficient pressure to enter a sales line, or if a sales line is not available. There is no current requirement for REC, and the Public Service Commission (PSC) has not historically authorized construction of sales lines before the first well is drilled on a pad (see Section 8.1.2.1 for a discussion of the PSC's role and a presentation of reasons why pre-authorization of gathering lines have been suggested under certain circumstances), therefore, estimates of emissions from both flaring and venting of flowback gas are included in the emissions tables in Section 6.5.1.5. Unless PSC revisits this policy in the future in order to allow for REC, the well pad activities would be required to minimize these emissions due to the potential for relatively high short-term VOC and CO emissions, as estimated by the Industry Information Report. The modeling and regional emission assessments, as well as regulatory applicability discussions, have incorporated industry's quantifications of the short term operations associated with flaring and venting. Thus, the well permitting process would be constrained by the assumed amount of gas to be vented or flared (or the corresponding average maximum hours of operations).

Also, during drilling, gaseous zones can sometimes be encountered such that some gas is returned with the drilling fluid, which is referred to as a gas “kick.” For safety reasons, the drilling fluid is circulated through a “mud-gas separator” as the gas kick is circulated out of the wellbore. Circulating the kick through the mud-gas separator diverts the gas away from the rig personnel. Any gas from such a kick is vented to the main vent line or a separate line normally run adjacent to the main vent line.

Drilling in a shale formation does not result in significant gas adsorption into the drilling fluid as the shale has not yet been fractured. Experience in the Marcellus thus far has shown few, if any, encounters with gas kicks during drilling. However, to account for the potential of a gas kick where a “wet” gas from another formation might result in some gas being emitted from the mud-gas separator, an assumed wet-gas composition was used to estimate emissions.

Gas from the Marcellus Shale in New York is expected to be “dry”, i.e., have little or no VOC content, and “sweet”, i.e., have little or no H₂S. Except for drilling emissions, two sets of emissions estimates are made to enable comparison of emissions of VOC and HAP from both dry gas production and wet gas production.

6.5.1.4 Number of Wells Per Pad Site

Drilling as many wells as possible from a single well pad provides for substantial environmental benefits from less road construction, surface disturbance, etc. Also, experience shows that average drilling time can be improved as more experience is gained in a shale play. Based on industry information submitted in response to Department requests, it is expected that no more than four wells could be drilled, completed, and hooked up to production in any 12-month period. Therefore, the annual emission estimates presented in Section 6.5.1.7 are based on an assumed maximum of four wells per site per year.

6.5.1.5 Natural Gas Condensate Tanks

Fluids that are brought to the surface during production at natural gas wells are a mixture of natural gas, other gases, water, and hydrocarbon liquids (known as condensate). Some gas wells produce little or no condensate, while others produce large quantities. The mixture typically is sent first to a separator unit, which reduces the pressure of the fluids and separates the natural gas

and other gases from any entrained water and hydrocarbon liquids. The gases are collected off the top of the separator, while the water and hydrocarbon liquids fall to the bottom and are then stored on-site in storage tanks. Hydrocarbons vapors from the condensate tanks can be emitted to the atmosphere through vents on the tanks. Condensate liquid is periodically collected by truck and transported to refineries for incorporation into liquid fuels, or to other processors.

Initial analysis of natural gas produced at Marcellus Shale horizontal gas well sites in Pennsylvania's Marcellus Shale area indicates insufficient BTEX and other liquid hydrocarbon content to justify installation of collection and storage equipment for natural gas liquids. However, in the instances where "wet" gas is encountered and there is a need to store the condensate in tanks either at the well pad or at the compressor station, potential VOC and HAP (e.g., benzene) emissions should be minimized to the maximum extent practicable and controlled where necessary. The ALL report notes that it is difficult to properly quantify the loss of vapors from these tanks, but notes that in states where substantial quantities of condensate are recovered, either a vapor recovery system or flaring is used to control emissions. If such condensate tanks are to be used in New York, a vapor recovery system would be required to be installed instead of flaring the emissions since the latter creates additional combustion emissions and other potential issues.

6.5.1.6 Emissions Tables

Estimated annual emissions from drilling, completion and production activities are based on industry's response to the Department's information requests⁷⁶ (hereafter Industry Information Report) that a maximum number of four wells would be drilled at a given pad in any year (see further discussion in the modeling section). These estimates are presented in Table 6.7, Table 6.8, Table 6.9, and Table 6.10 below.

ALL Consultant Information Request Report on behalf of IOGANY, dated September 16, 2010.

Table 6.7 - Estimated Wellsite Emissions (Dry Gas) - Flowback Gas Flaring (Tpy)(Updated July 2011)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	0.5	0.2	0.2	0.9	1.4	2.3
NO _x	15.1	5.8	3.8	24.7	4.9	29.6
CO	8.3	3.2	9.2	20.7	24.5	45.2
VOC	0.8	0.2	2.4	3.4	0.7	4.1
SO ₂	0.02	0.01	0.07	0.1	0.0	0.1
Total HAPs	0.09	0.02	0.03	0.14	0.08	0.22

Table 6.8 - Estimated Wellsite Emissions (Dry Gas) - Flowback Gas Venting (Tpy)(Updated July 2011)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	0.5	0.2	0.2	0.9	0.0	0.9
NO _x	15.1	5.8	3.8	24.7	0.0	24.7
CO	8.3	3.2	9.2	20.7	0.0	20.7
VOC	0.8	0.2	2.4	3.4	0.6	4.0
SO ₂	0.02	0.01	0.07	0.1	0.0	0.1
Total HAPs	0.09	0.02	0.03	0.14	0.0	0.14

Table 6.9 - Estimated Wellsite Emissions (Wet Gas) - Flowback Gas Flaring (Tpy) (Updated July 2011)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	0.5	0.2	0.2	0.9	1.4	2.3
NO _x	15.1	5.8	3.8	24.7	4.9	29.6
CO	8.3	3.2	9.2	20.7	24.5	45.2
VOC	0.8	0.2	2.4	3.4	0.7	4.1
SO ₂	0.02	0.01	0.07	0.1	0.22	0.31
Total HAPs	0.09	0.02	0.31	0.42	0.69	1.11

Table 6.10 - Estimated Wellsite Emissions (Wet Gas) - Flowback Gas Venting (Tpy) (Updated July 2011)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	0.5	0.2	0.2	0.9	0.0	0.9
NO _x	15.1	5.8	3.8	24.7	0.0	24.7
CO	8.3	3.2	9.2	20.7	0.0	20.7
VOC	0.8	0.2	2.4	3.4	21.9	25.3
SO ₂	0.02	0.01	0.07	0.1	0.0	0.1
Total HAPs	0.09	0.02	0.31	0.42	0.002	0.422

It is important to understand that the “totals” columns in these tables are not meant to be compared to the major source thresholds discussed in section 6.5.1.2 for the purpose of determining source applicability to the various regulations. This is because these estimates include emissions from activities which are not considered stationary sources, as detailed in the discussions in Section 6.5.1.9. These estimates should be looked upon merely as giving a relative sense of the expected well pad emissions and what the relation is to major source thresholds.

6.5.1.7 Offsite Gas Gathering Station Engine

For gas gathering compression, it is anticipated that most operators would select a large 4-stroke lean-burn engine because of its fuel efficiency. A typical compressor engine is the 1,775-hp Caterpillar G3606, which is the engine model used for the analysis.

The final revision to NESHAPs Subpart ZZZZ has placed very strict limits on formaldehyde emissions from reciprocating internal combustion engines (see Appendix 17). Future, 4-stroke lean-burn engines would be required to have an oxidation catalyst that would reduce formaldehyde emissions by approximately 90%.

The annual emissions data for a typical gas gathering compressor engine is given in Table 6.11 below.⁷⁷

Table 6.11 - Estimated Off-Site Compressor Station Emissions (Tpy)

Component	Controlled 4-Stroke Lean Burn Engine
PM	0.5
NO _x	33.3
CO	6.6
SO ₂	0.0
Total VOC	5.0
Total HAP	2.7

⁷⁷ ALL, August 26, 2009.

6.5.1.8 Department Determinations on the Air Permitting Process Relative to Marcellus Shale High-Volume Hydraulic Fracturing Development Activities.

A determination would first be made as to whether these internal combustion engines (ICEs) would qualify for the definition of non-road or stationary sources. This, in turn, determines whether the engines are subject to requirements such as NSPS or NESHAPs.

When considering applicability of these rules, engines can fall into three general classes: stationary, mobile, or nonroad. The applicable NSPS regulations (40 CFR Part 60, Subpart IIII and Subpart JJJJ) and NESHAP (40 CFR Part 63 Subpart ZZZZ) define stationary internal combustion engines as excluding mobile engines and nonroad engines. The New York State definition of stationary sources given in 6.5.1 also notes the non-road engine exclusion. The latter engines are defined at 40 CFR Part 1068 (General Compliance Provisions for Nonroad Program), which is virtually the same as it appears in 40 CFR Part 89 (Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines) as well as in New York's regulations at NYCRR Part 200.1, as given in Section 6.5.1. Paragraph (1)(iii) of the definition describes a nonroad engine that would be portable or would be part of equipment that would be considered portable, with the exception given in paragraph 2(iii) if the engines are to remain at the same location for more than 12 months.

It is clear from the Industry Information Report that the engines used to power the drilling and well development equipment would be used at a given well pad for maximum of less than half a year (see discussions in ALL, 8/26/09 and the modeling section on the timeframes of engine use), even if the maximum of four wells per pad were to be completed in a year. Thus, these engines are considered as nonroad engines and are not subject to the NSPS, NESHAP or permitting requirements.

However, as detailed in the following section, the environmental consequences of these engines are fully analyzed and mitigated where necessary in keeping with SEQRA. For example, the use of ULSF with a 15 ppm sulfur content would be required for use in all drilling and well development equipment engines. This limit is required for stationary engines in the final NESHAPS Subpart ZZZZ rule as discussed in Appendix 17. In addition, a set of control measures would be required on most of these engines in order to meet NAAQS, as fully

addressed in the modeling analysis section. The permitting of the various activities associated with drilling and development activities in the Marcellus Shale would be consistent with regulatory scheme in 6 NYCRR Part 200, et. seq. for regulating emissions of air pollutants. Thus, the Department would not subject the nonroad engines to the regulatory requirements applicable to stationary source, such as the determination of what constitutes a major source per Part 201. In instances throughout the country reviewed by the Department in terms of permitting gas drilling and production activities, the determination of a stationary source or facility has relied on the association of the compressor stations and nearby well emissions, but in none of these were the nonroad engine emissions included in the permitting emission calculations. This approach would also be followed in New York as the appropriate regulatory scheme.

Thus, in accounting for the well site operation emissions in the permitting process, the emissions from Tables 1 to 4 above would only include the remaining activities at the site which are essentially a small line heater (1 million Btu) a small compressor (150 horsepower), and possibly a flare. Tables 1 to 4 indicate that for the three higher emission pollutants, NO_x, CO and VOCs, these sources would add up to a maximum of 8.7, 33.7, and 3.1 Tpy, respectively, under the normal dry gas scenario for each pad. In the unlikely event of encountering “wet” gas, the VOC emissions could be 24.3 Tpy. However, these CO and VOC emissions are associated with the transient sources, the flare and gas venting, respectively, which are to be minimized, as would be apparent in the discussions to follow. In addition, in the unlikely event that a glycol dehydration would be located at a well site instead of the compressor station, the strict regulatory requirement noted in Section 6.5.1 would limit the VOC (benzene) emissions to below 1 Tpy. Thus, total HAPs emissions from a well pad would be much less than even the major source threshold of 10 Tpy for a single HAP.

Therefore, the process which the Department would follow in permitting the air emissions from Marcellus Shale activities would start with the compressor station permit application review. As noted in Section 8.1.2.1, this SGEIS for drilling wells is not meant to address the full extent of the compressor station permitting and the environmental consequences, which falls under the purview of the PSC and would be dealt with on a case by case basis. The applicable Public Service Law, Article VII, would be followed in which PSC would be the lead agency for the environmental review, however the Department would remain the agency responsible for

reviewing and acting on the air permit application. In this review, the Department would incorporate all of the applicable regulations, including the determination of what constitutes a source or facility. The air quality analysis has considered the impacts of a potential compressor station which is hypothetically placed next to the well pad in the modeling assessment of standards and other compliance thresholds.

Section 112(n) of the CAA (Section 112) applies specifically to HAPs. The EPA, on September 22, 2009, clarified that for the purposes of New Source Review (NSR) and Title V applicability review, the process of facility determination should include a detailed consideration of the traditional set of three criteria used by EPA in past actions. In this determination, a set of related and adjacent activities could be “aggregated” if they meet the requirements of the criteria.

The Department would follow EPA’s process for the determination of a stationary source or facility for criteria pollutants, as also guided by recent applicability determinations by EPA and other states. Details of the Department’s approach are presented in Appendix 18. The process would involve requesting information during the compressor station permit application phase using a set of questions framed from previous EPA determinations. A sentinel aspect of EPA’s regulation and policy, which New York’s approach is adapting, is the use of case-by-case information to make an informed decision. That process would also consider information requested on drilling wells which could be associated with the compressor stations.

6.5.2 Air Quality Impact Assessment

6.5.2.1 Introduction

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 the Department’s Division of Air Resources (DAR). The original modeling analysis was carried out to determine whether the various expected operations at a “typical” multi-well site would have the potential for any adverse air quality impacts, and it addressed a number of issues raised in public comments during the SGEIS scoping process. The analysis also incorporated subsequently-developed information on operational scenarios specific to multi-well horizontal drilling and hydraulic fracturing, to help determine possible air permitting requirements.

The initial modeling analysis has been updated based on information from both the Industry Information Report and related public information which has become available since September 2009. In particular, industry has indicated 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 would be four in any 12-month period; and 3) flowback impoundments are not contemplated. The effects of these operational changes are discussed where appropriate. It is to be noted that the revision from maximum of ten wells down to four wells per pad per year affects only the annual emissions and the modeled annual impacts and not the short term impacts. Therefore, the annual impacts were revisited to determine if the reduced emissions had an effect on the previous conclusions reached on standards compliance. In instances where previous impacts due to emissions using ten wells did not pose an exceedance, the annual impacts have not been recalculated since these represent conservative concentrations versus the revised maximum of four well operations. Instances where this approach is used are noted in the subsequent discussions.

Due to remaining issues with exceedances of the 24-hour PM_{2.5} ambient standard and the adoption of new 1-hour SO₂ and NO₂ standards by EPA since the initial modeling analysis, a supplemental modeling analysis was performed. The approach to this assessment and the consequent results are presented in a separate section which follows this section. That assessment has incorporated the discussions from an industry modeling exercise for PM_{2.5} and PM₁₀, as well as more recent EPA guidance documents on modeling for these pollutants.

This section presents the initial air quality analysis undertaken by DAR staff based on operational and emissions information supplied mainly by industry and its consultant in a submission hereafter referred to as the Industry Information Report.⁷⁸ To a limited extent, certain supplemental information from ICF International's report to NYSERDA⁷⁹ was also used. The applicability determinations of the Department's air permitting regulations and the verification approach to the emission calculations are contained in Section 6.5.2.

⁷⁸ ALL Consulting, 2009,

⁷⁹ ICF Task 2, 2009,

To the extent that the information being used was for the modeling of a generic multi-well site and its operations, it was necessary to reconcile and define a “worst case” scenario for the various activities in terms of expected impacts. Certain assumptions were made on the type and sizes of equipment to be used, the potential for simultaneous operation of the equipment on a short-term basis (i.e., hourly and daily), and the duration of these activities over a period of a year in order to be able to compare impacts to the corresponding ambient thresholds. The supplemental modeling analysis indicates that, although the operational time frame for certain equipment (e.g., engines) over a given year would be reduced according to the Industry Information Report,⁸⁰ the consequences of these reduced annual emissions are only qualitatively addressed in the following sections since these do not affect any of the initial conclusions reached on annual impacts. That is, the reduced annual emissions from certain operations which were initially demonstrated to meet the corresponding standards and thresholds would only be lowered by this new information.

The air quality analysis relied upon recommended EPA and the Department’s air dispersion modeling procedures to determine “worst case” impacts of the various operations and activities identified for the horizontal multi-well sites. Dispersion modeling is an acceptable tool, and at times the only option, to determine the impacts of many source types in permitting activities and environmental impact statements. Where necessary, the analysis approach relied on assumed worst case emissions and operations scenarios due to not only the nature of this generic assessment, but also because detailed model input data for the sources and their relative locations on a typical well pad cannot be simply identified or analyzed. Modeling was performed for various criteria pollutants (those with NAAQS) and a set of non-criteria pollutants (including toxics) for which New York has established a standard or other ambient threshold levels. Some of these toxic pollutants were identified in public comments during the SGEIS scoping process and were quantified to the extent possible for both the modeling and applicability determinations.

The following sections describe the basic source categories and operations at a typical multi-well site with hydraulic fracturing, the modeling procedures and necessary input data, the resultant impacts, and a set of conclusions drawn from these results. These conclusions are meant to

⁸⁰ All Consulting, 2010.

guide the set of conditions under which a site specific assessment might or might not be necessary. Based on information in the Industry Information Report and an update to EPA's dispersion model, the initial PM10/PM2.5 modeling approach and conclusions have been updated.

6.5.2.2 Sources of Air Emissions and Operational Scenarios

In order to properly estimate the air quality impacts of the set of sources at a single pad with multiple horizontal wells, the operating scenarios and associated air emission sources would be correctly represented. Since these operations have a number of interdependent as well as independent components, the Department has defined both the short-term and long term emission scenarios from the various source types in order to predict conservative, yet realistic impacts. The information used to determine the emission sources and their operating scenarios and constraints, as well as the associated emission rates and parameters, were provided by the Industry Information Report, while certain operational scenario restrictions were presented in the ICF report, which reflects information obtained from industry with drilling activities in other states. Where necessary, further data supplied by industry or determined appropriate by DMN was used to fill in data gaps or to make assumptions. In some of these instances, the lack of specific information necessitated a worst-case assumption be made for the purposes of the modeling exercise. Examples of the latter include defining "ambient air" based on the proximity of public access to the well pad and the likely structure dimensions to calculate their influence on the stack plumes.

The Industry and ICF Reports indicate three distinct operation stages and four distinct source types of air emissions for developing a representative horizontally-drilled multi-well pad. The phases are drilling, completion, and gas production, each of which has either similar or distinct sources of air emissions. These phases and the potential air pollution sources are presented in the Industry Information Report, Section 2.1.5 and Exhibit 2.2.1 of the ICF report, and in Chapter 5 of the SGEIS, and would only be briefly noted herein. Of the various potential sources of air emissions, a number have distinct quantifiable and continuous emissions which lend themselves to modeling. On the other hand, the ICF report also identifies other generic sources of minor fugitive emissions (e.g., mud return lines) or of emergency release type (e.g., BOP stack), or of a pollutant which is quantified only as of "generic" nature (total VOCs for

tanks) which cannot be modeled to any reliable extent without a well-defined source. The best approach to address these sources is to apply best minimization techniques, as recommended in Section 6.5.1.5 for condensate tanks. However, in instances where speciated VOCs or HAPs are available and provided by industry, such as for the glycol dehydrator and flowback venting of gas, the modeling was used to predict impacts which were then compared to available ambient thresholds.

The total operations associated with well drilling can be assigned to three “types” of potential sources: 1) combustion from engines, compressors, line heaters, and flares; 2) short-term venting of gas constituents which are not flared; and 3) emissions from truck activities near the well pad. Each of these source categories have limitations in terms of the size and number of the needed equipment, their possible simultaneous operations over a short-term period (e.g., 24-hour), and the time frames over which these equipment or activities could occur over a period of one year, which effects the corresponding annual impacts. Some of these limitations are described in the Industry Information Report. These limitations and further assumptions were taken into account in the modeling analysis, as further discussed in Section 6.5.2.3.

Many of the sources for which the Industry Information Report tabulates the drilling, completion and production activities are depicted in the typical site layout represented schematically in Exhibit 2.1.3 of the ICF report. The single pad for multi-horizontal wells is confined to an area of about 150 meters (m) by 150 m as a worst case size of the operations. From this single pad, wells are drilled in horizontal direction to develop an area of about one square mile. The initial industry report noted the possibility of up to ten horizontal wells being eventually drilled and completed per pad over a year’s time, while the ICF report notes that simultaneous drilling and completion on the same pad would be limited to a single operation for each. This limitation was determined appropriate by DMN for analysis of short-term impacts. Thus, the simultaneous operations on a pad for the assessment of impacts of 24 hours or less is limited to the equipment necessary to drill one well and complete another. In addition, according to DMN, there is a potential that a third well’s emissions could be flared at the same time as these latter operations. Thus, this source was also included in the simultaneous operation scenario for criteria pollutants. The Industry Information Report indicates that the number of wells drilled in a year at a given well pad would be four and asserts that there would not be any simultaneous operations of the

well drilling and completion equipment engines. These revisions are incorporated in the supplemental modeling analysis section. Their influence on the results in this section is addressed in places where deemed of consequence.

It should be noted that no emissions of criteria pollutants resulting from uncontrolled venting of the gas are expected. The other sources which could emit criteria pollutants are associated with the production phase operations; that is, the off-site compressors and line heaters could be operating simultaneously with the single pad drilling, completion and flaring operations. The Industry Information Report provides data for a possible “on-site” line heater instead of at the compressor station and this source was placed on the pad area and provides for a more conservative impact.

The Industry Information Report also provides emission data for the non-criteria pollutants as species of VOCs or HAPs associated with both combustion and gas venting. Review of this information indicates two essentially different sets of sources which can be treated independently in the modeling analysis. The first set is the gas venting sources: the mud-gas separator, the flowback gas venting, and the glycol dehydrator. These sources emit a distinct set of pollutants associated with the “wet” gas scenario, defined in the Industry Information Report as containing “heavier” hydrocarbons such as benzene. The industry and ICF reports note that gas samples in the Marcellus Shale have detected neither these heavier species of VOCs, nor H₂S. However, the Industry Information Report also notes the possibility of gas pockets with “wet” gas and provides associated emissions. To be comprehensive, the modeling analysis has calculated the impacts of these species which could be realized in the westernmost part of New York according to DMN.

The Industry Information Report also notes that gas venting is a relatively short-term phenomenon, especially during the flowback period where the vented gas is preferentially flared after a few hours of venting. Since there are essentially no simultaneous short-term emissions expected of the same pollutants at the pad from processes other than flowback venting, coupled with the clear dominance of the flowback venting emissions of these pollutants, the modeling was simplified for this scenario and only the short-term impacts were determined, as described in more detail in Section 6.5.1.3. The second set of non-criteria pollutant emissions presented in the Industry Information Report is associated mainly with combustion sources. These non-

criteria pollutants could be emitted over much longer time periods, considering these sources are operated over these longer periods, both per-well drilling activity and potential multi-well operations over a given year. Thus, for these pollutants, both short-term and annual impacts were calculated. It should be noted that, since the glycol dehydrator could operate for a full year also, its emissions of the same pollutants as those due to combustion were also included in this assessment of both short-term and annual toxic impacts. Furthermore, the flare emissions are included in the combustion scenario (and not in the venting), as the flaring of flowback gas results in over 95% destruction of these pollutants.

In addition, due to the conversion of H₂S to SO₂ during flaring, the flare was included in the criteria pollutant simultaneous operations scenario modeling. Table 6.12 summarizes the set of sources and the pollutants which have been modeled for the various simultaneous operations for short-term impacts. The specific modeling configuration and emissions data of the various sources are discussed in Section 6.5.2.3.

The last type of emission source associated with the multi-well operations is truck traffic. An estimate of the number of trucks needed for the various activities at a single well pad, including movement of ancillary equipment, delivery of fresh water and proppant/additives, and the hauling of flowback is presented in Section 6.11. It should be first noted that direct emissions from mobile sources are controlled under Title II of the CAA and are specifically exempt from permitting activities. Thus, these emissions are also not addressed in general in a modeling analysis, with two exceptions. At times, the indirect emissions of fugitive particulate matter are modeled when estimates of emissions are large. The latter occurs mainly due to poor dust control measures and the best approach to mitigate these emissions is to have a dust control plan. In addition, emissions of PM_{2.5} from mobile sources associated with a project and which occur on-site are to be addressed by the Department's Commissioner's Policy CP-33.⁸¹ Again, if these emissions are large enough, a modeling analysis is performed for an EIS. For the assessment of PM_{2.5} per CP-33, the emission calculations are not to include those associated with incidental roadway traffic away from the onsite operations.

⁸¹ <http://www.dec.ny.gov/chemical/8912.html>.

Emissions of both PM10 and PM2.5 due to truck operations at the well pad were initially calculated by DAR's Mobile Source Panning Section based on the movement of total number of trucks on-site for the drilling of one well. These emissions were then multiplied by the 10 potential wells which might be drilled over a year, and resulted in relatively minor quantities of 0.2 Tpy maximum PM2.5 emissions. This is consistent with the limited use of trucks at the well pad. These emissions are well below the CP-33 threshold of 15 Tpy. Thus, no modeling was performed for these pollutants and any necessary mitigation scheme for these would be the application of an appropriate dust control methods and similar limitations on truck usage, such as inordinate idling.

In order to address on-road truck traffic movement and emissions in the area underlain by the Marcellus Shale, estimates of regional emissions have been calculated based on information provided in the Industry Information Report. These regional emissions and their consequence are discussed in the section to follow. In addition, at the well pad, EPA's updated emission model MOVES (Motor Vehicle Emission Simulator) was used instead of the MOBILE 6e model used in the initial analysis. The MOVES model was also applied to generate regional emissions of on-road mobile sources associated with Marcellus Shale well development and included PM2.5 emissions. These estimates have been incorporated in the discussions of regional annual emissions. Results from the MOVES model indicate that the very low PM2.5 emissions initially estimated for a single pad are unchanged.

6.5.2.3 *Modeling Procedures*

EPA⁸² and Department⁸³ guidelines on air dispersion modeling recommend a set of models and associated procedures for assessing impacts for a given application. For stationary sources with “non-reactive” pollutants and near-field impacts, the refined AERMOD model (latest version, 07026) and its meteorological and terrain preprocessors is best suited to simulate the impacts of the sources and pollutants identified in the Marcellus Shale and other gas reservoir operations. This model is capable of providing impacts for various averaging times using point, volume or area source characteristics, using hourly meteorological data and a set of receptor locations in the

⁸² Appendix W to 40 CFR Part 51. http://www.epa.gov/ttn/scram/guidance_permit.htm.

⁸³ <http://www.dec.ny.gov/chemical/8923.html>.

surrounding area as inputs. The model simulates the impact of “inert” pollutants such as SO₂, NO₂, CO, and particulates without taking into account any removal or chemical conversions in air, which provides for conservative ambient impacts. However, these effects are of minor consequences within the context of plume travel time and downwind distances associated with the maximum ambient impact of pollutants discussed in this section.

AERMOD also does not treat secondary formation of pollutants such as O₃ from NO_x and VOCs, but it can model the non-criteria and toxic pollutant components of gas or VOC emissions in relation to established ambient thresholds. There does not exist a recommended EPA or Department “single” source modeling scheme to simulate O₃ formation from its precursors. This would involve not only complex chemical reactions in the plumes, but also the interaction of the regional mix of sources and background levels. Such an assessment is limited to regional scale emissions and modeling and is outside the scope of the modeling analysis undertaken for this section. However, the potential consequences of regional emissions of VOCs and NO_x are presented in Section 6.5.3.

Thus, the AERMOD model was used with a set of emission rates and source parameters, in conjunction with other model input data discussed in the following subsections, to estimate maximum ambient impacts, which were then compared to established Federal and New York State ambient air quality standards (AAQS) and other ambient thresholds. The latter are essentially levels established by the Department’s Division of Air Resources (DAR) program policy document DAR-1.⁸⁴ These levels are the 1-hour SGCs and annual AGCs (short-term and annual guideline concentration, respectively). Where certain data on the chemicals modeled and the corresponding ambient thresholds were missing, New York State Department of Health (NYSDOH) staff provided the requested information. For the thresholds, the Department’s Toxics Assessment section then calculated the applicable SGCs and AGCs. The modeling procedures also invoke a number of “default” settings recommended in the AERMOD user’s guide and EPA’s AERMOD Implementation Guide. For example, the settings of potential wells are not expected to be in “urban” locations, as defined for modeling purposes and, thus, the rural option was used. Other model input data are described next.

⁸⁴ <http://www.dec.ny.gov/chemical/30560.html>.

Meteorological Data

The AERMOD model requires the use of representative hourly meteorological data, which includes parameters such as wind speed, wind direction, temperature and cloud cover for the calculation of transport and dispersion of the plumes. A complete set of all the parameters needed for modeling is generally only available from National Weather Service (NWS) sites. The “raw” data from NWS sites are first pre-processed by the AERMET program and the AERSURFACE software using land use data at the NWS sites, which then create the necessary parameters to be input to AERMOD. There is a discrete set of NWS sites in New York which serves as a source of representative meteorological data sites for a given project. However, for this analysis, the large spatial extent of the Marcellus Shale necessitated the use of a number of the NWS site data in order to cover the meteorological conditions associated with possible well drilling sites throughout the State.

Figure 6.4 presents the spatial extent of the Marcellus Shale and the six NWS sites chosen within this area and deemed adequate for representing meteorological conditions for the purpose of dispersion modeling of potential well sites. It was judged that these sites would adequately envelope the set of conditions which would result in the maximum impacts from the relatively low-elevation or ground-level sources identified as sources of air pollutants. In addition, EPA and Department modeling guidance recommends the use of five years of meteorological data from a site in order to account for year to year variability. For the current analysis, however, the Department has chosen two years of data per site to gauge the sensitivity of the maxima to these data and to limit the number of model calculations to a manageable set. It was determined that impacts from the relatively low-elevation sources would be well represented by the total of 12 years of data used in the analysis.

This analysis is conservative from the standpoint of the number of data years used. Certain public comments⁸⁵ recommended that the Department should use the EPA-recommended five years of data for its analysis. However, these comments do not fully recognize the conservative nature of using 12 years of meteorological data to determine the worst case impact for any potential site in the Marcellus Shale play. While the EPA and the Department guidance to use

⁸⁵AKRF Consultants 12/3/2009, p. 2.

five years of data applies to individual meteorological site analysis to account for possible climatological variability at the particular site, the use of 12 years of data from six different sites has a similar conservatism built into it by the end use of the overall maxima for any well pads or compressor stations. That is, the overall maxima for any specific pollutant and averaging time could be controlled by meteorological data from different NWS sites, but these maxima are being used for all potential sites in the Marcellus Shale play regardless of whether they might experience these meteorological conditions. A review of the results discussed in the next section and in Table 6.16 confirms this conclusion. Thus, it is deemed that the use of two years of data from six NWS sites to assess the maximum potential impacts is conservative.

The NWS sites and the two years of surface meteorological data which were readily available from each site are presented in Table 6.13, along with latitude and longitude coordinates. In addition to these surface sites, upper air data is required as input to the AERMOD model in order to estimate certain meteorological parameters. Upper air data is only available at Buffalo and Albany for the sites chosen for this analysis, and were included in the data base. It should be noted that upper air data is not the driving force relative to the surface data in modeling low-elevation source impacts within close proximity of the sources, as analyzed in this exercise. The meteorological data for each year was used to calculate the maximum impacts per year of data and then the overall maxima were identified from these per the regulatory definitions of the specific AAQS and SGCs/AGCs, as detailed in the subsequent subsection.

Receptor and Terrain Input Data

Ground level impacts are calculated by AERMOD at user defined receptor locations in the area surrounding the source. These receptors are confined to “ambient air” locations to which the public has access. Current DMN regulations define a set of “set back” distances from the well sites to roadways and residences. However, these set back distances (e.g., 25m) are defined from the wellhead for smaller “footprint” vertical wells relative to the size of the multi-pad horizontal wells. Furthermore, EPA’s strict definition of ambient air only excludes areas to which the public is explicitly excluded by enforceable measures such as fences, which might not be normally used by the industry. Thus, in order to determine the potential closest location of receptors to the well site, the modeling has considered receptors at distances as close as the boundary of a 150m by 150m well pad. On the other hand, it is clear from diagrams and pictures

of sample sites that the public would have no access to within the well pad area. However, the closest receptor to any of the sources was limited to 10m to allow for a minimum practical “buffer” zone between the equipment on the pad and its edge.

The location of the set of modeled receptors is an iterative process for each application in that an initial set is used to identify the distance to the maximum and other relatively high impacts, and then the grid spacing may need to be refined to assure that the overall maxima are properly identified. For the type of low-elevation and ground level sources which dominate the modeled set in this analysis, it is clear that maximum impacts would occur in close proximity to the sources. Thus, a dense grid of 10m spacing was placed along the “fencelines”, and extended on a Cartesian grid at 10 m grid spacing out to 100 m from the sources in all directions. In a few cases, the modeling grid was extended to a distance of 1000 m at a grid spacing of 25 m from the 100 m grid’s edge in order to determine the concentration gradients. For the combustion and venting sources, an initial grid at 10m increment was placed from the edge of the 150 m by 150 m pad area out to 1000 m, but this grid was reduced to a Cartesian grid of 20 m from spacing the “fenceline” to 500 m in order to reduce computation time. The revised receptor grid resolution was found to adequately resolve the maxima as well for the purpose of demonstrating the anticipated drop off of concentrations beyond these maxima.

The AERMOD model is also capable of accounting for ground level terrain variations in the area of the source by using U.S. Geological Survey Digital Elevation Model (DEM) or more recent National Elevation Data (NED) sets. However, for sources with low emission release heights, the current modeling exercise was performed assuming a horizontally invariant plane (flat terrain) as a better representation of the impacts for two reasons. First, given the large variety of terrain configurations where wells may be drilled, it was impractical to include a “worst case” or “typical” configuration. More importantly, the maximum impacts from the low-elevation sources are expected to occur close-in to the facility site, and any variations in topography in that area was determined to be best simulated by AERMOD using the concept of “terrain following” plumes.

It should be clarified that this discussion of terrain data use in AERMOD is distinct from the issue of whether a site might be located in a complex terrain setting which might create distinct

flow patterns due to terrain channeling or similar conditions. These latter mainly influence the location and magnitude of the longer term impacts and are addressed in this analysis to the extent that the set of meteorological data from six sites included these effects to a large extent. In addition, the air emission scenarios addressed in the modeling for the three operational phases and associated activities are deemed to be more constrained by short-term impacts due to the nature and duration of these operations, as discussed further below. For example, the emissions from any venting or well fracturing are intermittent and are limited to a few hours and days before gas production is initiated.

Emissions Input Data

EPA and Department guidance require that modeling of short-term and annual impacts be based on corresponding maximum potential and, when available, annual emissions, respectively. However, guidance also requires that certain conservative assumptions be made to assure the identification of maximum expected impacts. For example, the short-term emission rates have to represent the maximum allowable or potential emissions which could be associated with the operations during any given set of hours of the meteorological data set and the corresponding averaging times of the standards. This is to assure that conditions conducive to maximum impacts are properly accounted for in the varying meteorological conditions and complex dependence of the source's plume dispersion on the latter. Thus, for modeling of all short-term impacts (up to 24 hours); the maximum hourly emission rate is used to assure that the meteorological data hours which determine the maximum impacts over a given period of averaging time were properly assessed.

Based on the information and determinations presented in Section 6.5.1.2 on the set of sources and pollutants which need to be modeled, the necessary model input data was generated. This data includes the maximum and annual emission rates for the associated stack parameters for all of the pollutants for each of the activities. In response to the Department's request, industry provided the necessary model input data for all of the activities at the multi-well pad site, as well as at a potential offsite compressor. These data were independently checked and verified by DAR staff and the final set of source data information was supplied in the Industry Information Report noted previously. Although limited source data were also contained in the ICF report, the

data provided by industry were deemed more complete and could be substantiated for use in the modeling.

The sources of emissions specific to Marcellus Shale operations are treated by AERMOD as either point or area sources. Point sources are those with distinct stacks which can also have a plume rise, simulated by the model using the stack temperatures and velocities. An example of a point source is the flare used for short term periods. Area sources are generally low or ground level sources of distinct spatial dimensions which emit pollutants relatively uniformly over the whole of the area. The previously proposed flowback water impoundments are a good example of area sources. In addition to the emission rates and parameters supplied by industry, available photographs and diagrams indicated that many of the stacks could experience building downwash effects due to the low stack heights relative to the adjacent structure heights. In these instances, downwash effects were included in a simplified scheme in the AERMOD modeling by using the height and “projected width” of the structure. These effects were modeled to assure that worst case impacts for the compressors and engines were properly identified. The specific model input data used is described next, with criteria and non-criteria source configurations presented separately for convenience.

Criteria Pollutant Sources - The emission parameters and rates for the combustion source category at a multi-horizontal well pad were taken from data tables provided in the Industry Information Report. In some instances, additional information was gathered and assumptions made for the modeling. The report provides “average” and maximum hourly emission rates, respectively, of the criteria pollutants in Tables 7 and 8 for the drilling operations, Tables 14, 15, 20 and 21 for the completion phase operations, Table 18 for the production phase sources, and Table 24 for the offsite compressor. It should be noted that the criteria pollutant source emissions in these tables are not affected by the dry versus wet gas discussions, with the exception of SO₂ emissions from flaring of H₂S in wet gas. For this particular pollutant, the flare emission rate from Table 21 was used. Furthermore, the modeling has included the off-site compressor in lieu of the smaller onsite compressor at the wellhead and an onsite line heater instead of an offsite one in order to determine expected worst case operations impacts.

As discussed previously, initial modeling of both short-term and annual impacts were based on the maximum hourly emissions rates, with further analysis of annual impacts performed using more representative long term emissions only when necessary to demonstrate compliance with corresponding annual ambient thresholds. For the short-term impacts (less than 24-hour), it was assumed that there could be simultaneous operations of the set of equipment at an on-site pad area for one well drilling, one well completion, and one well flaring, along with operations of the onsite line heater and off site compressor for the gas production phase for previously-completed wells. For the modeling of the 24-hour PM2.5 impacts for the Supplemental Modeling section, the simultaneous operation scenario was not used based on the Industry Information Report. It should be clarified that although AERMOD currently does not include the flare source option in the SCREEN3 model, the heat release rate provided in Table 15 of the Industry Information Report was used to calculate the minimum flare “flame height” as the stack height for input to AERMOD.

The placement of the various pieces of equipment in Table 6.11 on a well pad site was chosen such as not to underestimate maximum offsite as well as combined impacts. For example, the schematic diagram in the ICF report represents a typical set up of the various equipment, but for the modeling of the sources which could be configured in a variety of ways on a given pad, the locations of the specific equipment were configured on a well pad without limiting their potential location being close to the property edge. That is, receptors were placed at distances from the sources as if these were near the edge of the property, with the “buffer zone” restriction noted previously. This was necessary since many of these low level sources could have maximum impacts within the potential 150m distance to the facility property and receptors could not be eliminated in this area.

At the same time, however, it would be unrealistic to locate all of the equipment or a set of the same multi-set equipment at an identical location. That is, certain sources such as the flare are not expected to be located next to the rig and the associated engines due to safety reasons. In addition, there are limits to the size of the “portable” engines which are truck-mounted, thus requiring a set of up to 15 engines placed adjacent to each other rather than treating these as a single emission point. Since there were some variations in the number and type of the multi-source engines and compressors specifically used for drilling and completion, a balance was

reached between using a single representative source, with the corresponding stack parameters and total emissions, versus using distinct individual source in the multi-source set. This determination was also dictated by the relative emissions of each source.

The modeling used a single source representation for the drilling engines and compressors from Table 8, while for the fracturing pump engines, five sources were placed next to each other to represent three—each of the potential fifteen noted in Table 15 of the Industry Information Report. The total emission rates for the latter sources were divided over the five representative sources in proper quantities. This scenario was revised for the Supplemental Modeling section by modeling each of the 15 completion equipment engines as individual point sources. The rest of the sources are expected to either be a single equipment or are in sets such that representation as a single source was deemed adequate. The one exception was the modeling of the NO₂ 1-hour standard as describe in the next section. Using sample photographs from existing operations in other states, estimates of both the location as well as the separation between sources were determined. For example, the size of the trucks with mounted fracturing engines was used to determine the separation between a row of the five representative sources. These photographs were also used to estimate the dimension of the “structures” which could influence the stack plumes by building downwash effects. All of the sources were deemed to have a potential for downwash effects, except for the flare/vent stack. The height and “effective” horizontal width of the structure associated with each piece of equipment were used in the modeling for downwash calculations.

It was also noted from the photographs that distinct types of rig engines and air compressors are used for the drilling operations, with one of the types having “rain-capped” stacks. This configuration could further retard the momentum plume rise out of the stack. Thus, for conservatism, this particular source was modeled using the “capped” stack option in AERMOD with the recommended low value for exit velocity. Revised industry information indicates that these “rain caps” open during engine operations and the supplemental modeling has incorporated this information. Furthermore, since the off-site “centralized” compressor could conceivably be located adjacent to one of the multi-well pads, this source was located adjacent to, but on the other side of the edge of the 150m by 150m pad site.

The placement of the various sources of criteria pollutants in the modeling is represented in Figure 6.5. The figure shows individual completion equipment engines as modeled in the supplemental analysis. This configuration was deemed adequate for the determination of expected worst-case impacts from a ‘typical’ multi-well pad site. Although the figure outlines the boundary of the 150m by 150m typical well pad area, it is again clarified that receptors were placed such that each source would have close-in receptors beyond the 10m “buffer” distance determined necessary from a practical standpoint. That is, receptors were placed in the pad area to assure simulation of any configuration of these sources on the pad at a given site.

Annual impacts were initially calculated using the maximum hourly emission rates, and the results reviewed to determine if any thresholds were exceeded. If impacts exceeded the annual threshold for a given pollutant, the “average” emission rates specifically for the drilling engines and air compressors in Table 7 and for the hydraulic fracturing and flaring operations from Table 20 of the Industry Information Report were used. For the other sources, such as the line-heater and offsite compressor, the average and maximum rates are the same as presented in Tables 18 and 24, respectively, and were not modified for the refined annual impacts. As these average rates account only for the variability of “source demand” for the specific duration of the individual operations, an additional adjustment needed to be made for the number of days in a year during which up to 10 such well operations would occur. Thus, from Tables 7 and 14, it is seen that there would be a maximum of 250 days of operations for the drilling engines, maximum of 20 days for hydraulic fracturing engines, and maximum of 30 days of flaring in a given year. Thus, for these sources, the annual average rate was adjusted accordingly. Although initial modeling included 10 wells per pad per year as an assumption, the resultant impacts were reviewed and relevant conclusions adjusted in the sections to follow where it was deemed of consequence to NAAQS or threshold compliance. That is, if the standards compliance was already demonstrated with the worst-case assumption of 10 wells, no revisions were necessary. On the other hand, the modeling has not included any operational limits on the use of the line heater and off-site compressor for the production phase and the annual emissions were represented by the maximum rates. Some of these considerations are further discussed in Section 6.5.2.4.

Lastly, in order to account for the possibility of well operations at nearby pads at the same time as operations at the modeled well pad configuration, a sensitivity analysis was performed to determine the potential contribution of an adjacent pad to the modeled impacts. This assessment addressed, in a simplified manner, the issue of the potential for cumulative effects from a nearby pad on the total concentrations of the modeled pad such that larger “background levels” for the determination of compliance with ambient threshold needed to be determined. The nearby pad with identical equipment and emissions as the pad modeled was located at a distance of one kilometer (km) from the 150m by 150m area of the modeled pad. This separation distance is the minimum expected for horizontal wells drilled from a single pad, which extends out to a rectangular area of 2500m by 1000m (one square mile).

Non-Criteria Pollutant Sources - There are a set of pollutants from two “distinct” sources in the Marcellus Shale operations for which there are no national ambient standards, but for which New York State has established either a state standard (H₂S) or toxic guideline concentrations. These are VOC species and HAPs which are emitted from: a) sources associated with venting of gas prior to the production phase; or b) as by-products of combustion of gas or fuel oil. A review of the data on these pollutants and their sources indicated that the two distinct source types can be modeled independently, as described below.

First, of the sources which vent the constituents of the “wet” gas (if it is encountered), the flowback venting has by far the most dominant emissions of the toxic constituents. The other two sources of gas venting are the mud-gas separator and the dehydrator, and a comparison of the relative emissions of the five pollutants identified in the Industry Information Report (benzene, hexane, toluene, xylene, and H₂S) from these three sources in Tables 8, 21 and 22 shows that the flowback venting has about two orders of magnitude higher emissions than the other two sources. As noted in the Industry Information Report, this venting is limited to a few hours before the flare is used, which reduces these emissions by over 90%. Thus, modeling was used to determine the short-term impacts of the venting emissions. Annual impacts were not modeled, due to the very limited time frame for gas venting, even if ten wells are to be drilled at a pad.

It was determined that during these venting events, essentially no other emissions of the same five toxics would occur from other sources. That is, even though a subset of these pollutants are also tabulated in the Industry Information Report at relatively low emissions for the engines, compressors and the flares, it is either not possible or highly unlikely that the latter sources would be operating simultaneously with the venting sources (e.g. gas is either vented or flared from the same stack). Thus, for the short-term venting scenario, only the impacts from the three sources need to be considered. It was also determined that rather than modeling each of the five pollutant for the set of the venting sources for each of the 12 meteorological years, the flowback venting source parameters of Table 15 were used with a unitized emission rate of 1 g/s as representative of all three sources. The actual pollutant specific impacts were then scaled with the total emissions from all three sources. This is an appropriate approximation, not only due to the dominance of the flowback vent emissions, but also since the stack height and the calculated plume heights for these sources are very similar. This simplification significantly reduced the number of model runs which would otherwise be necessary, without any real consequence to the identification of the maximum short-term impacts.

The next set of non-criteria pollutants modeled included those resulting from the combustion sources. It should be clarified that pollutants emitted from the glycol dehydrator (e.g. benzene), which are associated with combustion sources were also included in these model calculations for both the short-term and annual impacts. A review of the emissions in Tables 8, 18, 21, and 24 indicates seven toxic pollutants with no clear dominance of a particular source category. Furthermore, the sources associated with these pollutants have much more variability in the source heights than for the venting scenario. For example, the flare emissions of the three pollutants in Table 21 are higher than for the corresponding hydraulic fracturing pump engines, but the plume from the flare is calculated to be at a much higher elevation than those for the engines or compressors such that a “representative” source could not be simply determined in order to be able to model a unitized emission rate and limit the number of model runs.

However, it was still possible to reduce the number of model calculations from another standpoint. The seven pollutants associated with these sources were ranked according to the ratios of their emissions to the corresponding 1-hour SGCs and AGCs (SGCs for hexane and propylene were determined by Toxics Assessment section since these are not in DAR-1 tables).

These ratios allowed the use of any clearly dominant pollutants which could be used as surrogates to identify either a potential issue or compliance for the whole set of toxics. These calculations indicated that benzene and formaldehyde are clearly the two pollutants which would provide the desired level of scrutiny of all of the rest of the pollutants in the set. To demonstrate the appropriateness of this step, limited additional modeling for the annual impacts for acetaldehyde was also performed due to the relatively low AGC for this pollutant. These steps further reduced the number of model runs by a significant number.

The emission parameters, downwash structure dimension and the location of the sources were the same as for the criteria pollutant modeling. Similar to the case of the criteria pollutants, any necessary adjustments to the annual emission rates to provide more realistic annual impacts were made after the results of the initial modeling were reviewed to determine the potential for adverse impacts. These considerations are further discussed in the resultant impact section.

Pollutant Averaging Times, Ambient Thresholds and Background Levels

The AERMOD model calculates impacts for each of the hours in the meteorological data base at each receptor and then averages these values for each averaging time associated with the ambient standards and thresholds for the pollutants. For example, particulate matter (PM10 and PM2.5) has both 24-hour and annual standards, so the model would present the maximum impact at each receptor for these averaging times. As the form of the standards cannot be exceeded at any receptor around the source, the model also calculates and identifies the overall maximum impacts over the whole set of receptors.

For the set of pollutants initially modeled, the averaging times of the standards are: for SO₂- 3-hour, 24-hour, and annual; for PM10/PM2.5 - 24-hour and annual; for NO₂ - annual; for CO - 1-hour and 8-hour; and for the set of toxic pollutants – 1-hour SGCs and annual AGCs. For most criteria pollutants, the annual standards are defined as the maxima not to be exceeded at any receptor, while the short-term standards are defined at the highest-second-highest (HSH) level wherein one exceedance is allowed per receptor. The exception is PM2.5 where the standards are defined as the 3 year averages, with the 24-hour calculated at the 98th percentile level. The toxic pollutant SGCs and AGCs are defined at a level not be exceeded. In the Department's assessments, the maximum impacts for all averaging times were used for all pollutants, except

for PM_{2.5}, in keeping with modeling guidance for cases where less than five years of meteorological data per site is used.

In addition to the standards, EPA has defined levels which new sources or modifications after a certain time frame cannot exceed and cause significant deterioration in air quality in areas where the observations indicate that the standards are being met (known as attainment areas). The area depicted in Figure 6.4 for the Marcellus Shale has been classified as attainment for all of the pollutants modeled in the Department's analysis. Details on area designations and the state's obligation to bring a nonattainment area into compliance are available at the Department's public webpage as well as from EPA's webpage.⁸⁶ For the attainment areas, EPA's Prevention of Significant Deterioration (PSD) regulations define increments for SO₂, NO₂ and PM₁₀. More recently, EPA finalized the PSD increments for PM_{2.5}; these are discussed below. Although, in the main, the PSD regulations apply only to major sources, the increments are consumed by both major and minor sources and would be modeled to assure compliance. However, the PSD regulations also exempt "temporary" sources from having to analyze for these increments. It is judged that essentially all of the emissions at the well pad can be qualified as temporary sources since the expectation is that the maximum number of wells at a pad can be drilled and completed well within a year. Even if a partial set of the wells is drilled in a year and these operations cease, the increment would be "expanded" as allowed by the regulations.

The only exception to the temporary designation would be the offsite compressor and the line heater which can operate for years. Thus, only these two sources were considered in the increment consumption analysis. The applicable standards and PSD increments are presented in Table 6.14 for the various averaging times. Table 6.14 reflects incorporation of the 1-hour SO₂ and NO₂ NAAQS which are addressed in the supplemental modeling section. Furthermore, the final PSD increments for PM_{2.5}, which become effective on December 20, 2011, are added to the Table.⁸⁷ In addition to these standards and increments, the table provides EPA's defined set of Significant Impact Levels (SILs) which exist for most of the criteria pollutants. These SILs are at about 2 to 4% of the corresponding standards and are used to determine if a project would

⁸⁶ <http://www.dec.ny.gov/chemical/8403.html> and <http://www.epa.gov/ttn/naaqs/>.

⁸⁷ Prevention of Significant Deterioration for PM_{2.5}, final rule, Federal Register, Vol. 75, No. 202, October 20, 2010.

have a “significant contribution” to either an existing adverse condition or would cause a standards violation. Table 6.14 -also reflects the SILs for PM2.5 as contained in EPA’s final PSD rule.

These SILs are also used to determine whether the consideration of background levels, which include the contribution of regional levels and local sources, need to be explicitly addressed or modeled. When the SILs are exceeded, it is necessary to explicitly model nearby major sources in order to establish potential “hot spots” of exceedances to which the project might contribute significantly. For the present analysis, if the SILs are exceeded for the single multi-well pad, the Department has considered the potential for the contribution of nearby pads to the impacts of the former on a simplified level. The approach used was noted previously and involves the modeling of a nearby pad placed at 1000m distance from the pad for which detailed impacts were calculated, in order to determine the relative contribution of the nearby pad sources. If these results indicate the potential for significant cumulative effects, then further analysis would need to be performed.

On the other hand, in order to determine existing criteria pollutant regional background levels, which would be explicitly included in the calculation of total concentrations for comparison to the standards, the Department has conservatively used the maximum observations from a set of Department monitoring sites in the Marcellus Shale region depicted in Figure 6.4. The location of these sites and the corresponding data is available in the Department’s public webpage.⁸⁸ The Department has reviewed the data from these sites to determine representative, but worst case background levels for each pollutant. The Department has used maximum values over a three year period from the latest readily available tabulated information from 2005 through 2007 from at least two sites per pollutant within the Marcellus Shale area, with two exceptions. First, in choosing these sites, the Department did not use “urban” locations, which could be overly conservative of the general areas of well drilling. This meant that for NO₂ and CO, data from Amherst and Loudonville, respectively, were used as representative of rural areas since the rest of the Department’s monitor sites were all in urban areas for these two pollutants. Second, data for PM10 for the period chosen was not available from any of the appropriate sites due to

⁸⁸ <http://www.dec.ny.gov/chemical/8406.html>.

switching of these sites to PM_{2.5} monitoring per EPA requirements. Thus, the Department relied on data from 2002-04 from Newburgh and Belleayre monitors. The final set of data used for background purposes are presented in Table 6.14. These data represent worst case estimates of existing conditions to which the multi-well pad impacts would be added in order to determine total concentrations for comparison to the AAQS. In instances where the use of these maxima causes an exceedance of the AAQS, EPA and Department guidance identify procedures to define more case specific background levels. Per the Department's Air Guide-1, since there are no monitored background levels for the non-criteria pollutants modeled, the impacts of H₂S and rest of the toxic chemicals are treated as incremental source impacts relative to the corresponding standard and SGCs/AGCs, respectively. Determinations on the acceptability of these incremental impacts are then made in accord with the procedures in Air Guide-1.

The background levels for criteria pollutants relied upon in the initial modeling analysis are still deemed conservative based on a review of observed monitoring levels in more recent years for pollutants such as PM_{2.5}. Thus, most do not need to be updated. On the other hand, for PM_{2.5} 24-hour averages and the new 1-hour NO₂ and SO₂ standards, more refined background levels were determined as discussed in the supplemental modeling section.

6.5.2.4 Results of the Modeling Analysis

Using the various model input data described previously, a number of model calculations were performed for the criteria and toxic pollutants resulting from the distinct operations of the onsite and offsite sources. Each of the meteorological data years were used in these assessments and the receptors grids were defined such as to identify the maxima from the different sources. In some instances, it was possible to limit the number of years of data used in the modeling, as results from a subset indicated impacts well below any thresholds. In other cases, it was necessary to expand the receptor grid such that the decrease in concentration with downwind distance could be determined. These two aspects are described below in the specific cases in which they were used.

As described in the previous section, initial modeling of annual impacts was performed in the same model runs as for the short-term impacts, using the maximum emission rates. However, in a number of cases, this approach lead to exceedances of annual thresholds and, thus, more

appropriate annual emissions were determined in accord with the procedures described in Section 6.5.2.3, and the annual impacts were remodeled for all of the data years. These instances are also described below in the specific cases in which the annual emissions were used. The results from these model runs were then summarized in terms of maxima and compared to the corresponding SILs, PSD increments, ambient standards, and Air Guide-1 AGCs/SGCs.

This comparison indicated that, using the emissions and stack parameter information provided in the Industry Information Report, a few of the ambient thresholds could be exceeded. Certain of these exceedances were associated with conditions (such as very low stacks and downwash effects) which could be rectified relatively easily. Thus, some additional model runs were performed to determine conditions under which the ambient thresholds would be met. These results are presented below with the understanding that industry could implement these or propose their own measures in order to mitigate the exceedances. Results for the criteria pollutants are discussed first, followed by the results for the toxic/non-criteria pollutants.

Criteria Pollutant Impacts

The set of sources identified in Table 6.11 for short-term simultaneous operations of the various combustion sources with criteria pollutant emissions were initially modeled with the maximum hourly emission rate and one year of meteorological data. It was clear from these results that the annual impacts for PM and NO₂ had to be recalculated using the more appropriate annual emissions procedures discussed in Section 6.5.2.3. That is, for these pollutants, the “average” rates in the Industry Information Report were scaled by the number of days/hours of operations per year for the drilling engine/compressor, the hydraulic fracturing engines and the flare, and then these results were multiplied by ten to account for the potential of ten wells being drilled at a pad for a year. The rest of the sources were modeled assuming full year operations at the maximum rates. In addition, based in part on the initial modeling, two further adjustments were made to the annual NO₂ impacts. First, the model resultant impacts were multiplied by the 0.75 default factor of the Tier 2 screening approach in EPA’s modeling guidelines. This factor accounts for the fact that a large part of emissions of NO_x from combustion sources are not in the NO₂ form of the standard. The second adjustment related to the stack height of the off-site compressor, which was raised to 7.6m (25ft) based on the results for the non-criteria pollutants

discussed below; that is, this height was deemed necessary in order to meet the formaldehyde AGC.

Each of the meteorological data years was used to determine the maximum impacts for all of the criteria pollutants and the corresponding averaging times of the standards. However, in the case of 24-hour particulate impacts, modeling was limited to the initial year (Albany, 2007) for reasons discussed below. The results for each year modeled are presented in Table 6.15. It should be noted that the SO₂ annual impacts in this table are based on the maximum hourly rates and are very conservative. In addition, the tabulated values for the 24-hour PM_{2.5} impacts are the eight highest in a year, which is used as a surrogate for the three year average of the eight highest value (i.e., 99th percentile form of the standard). It is seen that the short-term impacts do not show any significant variability over the twelve years modeled.

The overall maxima for each pollutant and averaging time from Table 6.15 are then transferred to Table 6.17 for comparison to the set of ambient thresholds. These maximum impacts are to be added to the worst case background levels from Table 6.14 (repeated in Table 6.16), with the sum presented in the total concentration column. The impacts of only the compressor and the line heater are also presented separately in Table 6.16 for comparison to the corresponding PSD increments. It should be noted that, due to the low impacts for many of the pollutants from all of the sources relative to the increments, only the 24-hour PM₁₀ and PM_{2.5} and the annual NO₂ were re-calculated for the compressor and line heater, as noted in Table 6.16. In addition, due to the promulgated PSD increments for PM_{2.5} in the 10/20/10 final rule, the increments are reflected in Table 6.16, along with the corresponding PM_{2.5} impacts (conservatively assuming to equal PM₁₀ impacts). The rest of the impacts are the same as those in the maximum overall impact column.

The results indicate that all of the ambient standards and PSD increments would be met by the multiple well drilling activities at a single pad, with the exception of the 24-hour PM₁₀ and PM_{2.5} impacts. In fact, the 3-hour (and very likely the annual) SO₂ impacts are below the corresponding significant impact levels. This is a direct result of the use of the ultra low sulfur fuel assumed for the engines, which would have to be implemented in these operations. In addition, the level of compliance with standards for the maximum annual impacts for NO₂ and

PM2.5 are such as to require the implementation of the minimum 7.6 m (30feet) stack height for the compressor and general adherence to the annual operational restrictions identified in the Industry Information Report.

Table 6.16 results for 24-hour PM10 and PM2.5 impacts were limited to one year of meteorological data since these were found to be significantly above the corresponding standards, as indicated in Table 6.16. Unlike other cases, a simple adjustment to the stack height did not resolve these exceedances and it was determined that specific mitigation measures would need to be identified by industry. However, the Department determined one simple set of modeling conditions under which impacts can be resolved. It was noted that the relatively large PM10/PM2.5 impacts occurred very close to the hydraulic fracturing engines (and at lower levels near the rig engines) at a distance of 20 m, but there was also a very sharp drop-off of these concentration with distance away from these sources. Specifically, to meet the standards minus the background levels in Table 6.16, it was determined that the receptor distance had to be beyond 80 m for PM10, and 500 m for PM2.5. In an attempt to determine if a stack height adjustment in combination with a distance limitation for public access approach can also alleviate the exceedances, the rig engine and fracturing engine stacks heights were both extended by 3.1m (10ft). From the photographs of the truck-mounted engines, it was not clear if any extensions would be practical and, thus, only this minimal increase was considered. This scenario was modeled again with the Albany 2007 meteorological data. The resultant maximum impacts were reduced to 171 and 104 $\mu\text{g}/\text{m}^3$ for PM10 and PM2.5, respectively. For this case, in order to achieve the standards using Table 6.16 background levels, the receptors would be beyond 40 m and 500 m for PM10 and PM2.5, respectively. Thus, the stack height extension did not significantly affect the concentrations at the farther distances, as would be expected from the fact that building downwash effects are largest near the source. However, the background level for PM2.5 can be adjusted from the standpoint that the expected averages associated with these operations at relatively remote areas are better represented by the regional component due to transport. If the contribution of the latter to the observed maxima is conservatively assumed to be half of the value in Table 6.17 (i.e., 15 $\mu\text{g}/\text{m}^3$), then the receptor distance at which a demonstration of compliance can be made is approximately 150 m.

Thus, one practical measure to alleviate the PM10 and PM2.5 standard exceedances is to raise the stacks on the rig and hydraulic fracturing engines and/or erect a fence at a distance surrounding the pad area in order to preclude public access. Without further modifications to the industry stack heights, a fence out to 500 m would be required, but this distance could be reduced to 150 m with the taller stacks and a redefinition of the background levels. Alternately, there is likely control equipment which could significantly reduce particulate emissions. The set of specific control or mitigation measures would need to be addressed by industry.

Based on recent industry and public information, supplemental modeling analysis and detailed review of potential control measures and their practical use was undertaken. The preliminary results clearly indicate that certain levels of emission reductions are likely necessary for at least the completion equipment engines. The results of the supplemental modeling and the consequent recommended mitigation measure are presented in the two sections which follow.

An additional issue addressed in a simplified manner was the possibility of simultaneous operations at a nearby pad, which could be located at a minimum distance of one km from the one modeled, as described previously. It is highly unlikely than more than one additional pad would be operating as modeled simultaneously with other pads within this distance; it is more likely that drill rigs and other heavy equipment would be moved from one pad to another within a given vicinity, with sequenced operations. Regardless, the impacts of all the pollutants and averaging times were determined at a distance of 500 m from the modeled well pad for the years corresponding to the maximum impacts. This is half the distance to the nearest possible pad and allows the determination of potential “overlap” in impacts from the two pads. The concentrations at 500m drop off sharply from the maxima to below significance levels for almost all cases such that nearby pad emissions would not significantly contribute to the impacts from the modeled source. These impacts at 500m are presented in the last row of Table 6.16 and their comparisons to the corresponding SILs in Table 6.16 show only the 24-hour PM2.5 and annual NO₂ impacts are still significant at this distance.

Thus, there is a potential that for these two cases the nearby pad operations could contribute to another well operation’s impacts. This scenario was assessed by placing an identical set of sources at another pad at a distance of 1km from the one modeled in the general upwind

direction from the latter. Impacts were then recalculated on the same receptor grid using the years of modeled worst case impacts for these two pollutants and averaging times. The results indicated that the maximum impacts presented in Table 6.16 for annual NO₂ and 24-hour PM_{2.5} were essentially the same; in fact the 24-hour PM_{2.5} impacts are identical to the previous maxima while the NO₂ annual impact of 63.2 increased by only 1.2 µg/m³. Annual impacts from any other pad not in the predominant wind direction would be lower. These results are judged not to effect the compliance demonstrations discussed above. Thus, it is concluded that minimal interactions from nearby pad well drilling operations would result, even if there were to be such simultaneous operations.

In addition to these results, the modeled impacts discussed in the supplemental modeling section and the remediation measures recommended to resolve modeled exceedances of both the 24-hour PM_{2.5} and 1-hour NO₂ NAAQS would substantially reduce both the PM_{2.5} and NO₂ impacts from the levels in Table 6.15 at the 500 m distance. Therefore, compliance with standards and increments can be said to be adequately demonstrated on the basis of individual pad results.

Non-Criteria Pollutant Impacts

As discussed in Section 6.5.2.3, three “distinct” source types were independently modeled for a corresponding set of toxic pollutants: i) short-term venting of gas constituents, ii) combustion by-products, plus the emissions of the same pollutants from the glycol dehydrator, and iii) a set of representative chemicals from the flowback impoundments. These impacts were determined for comparison to both the short-term 1-hour SGC and annual AGC, with the exception of the venting scenario which was limited to the short-term impacts due to the very short time frame of the practice. The gas venting emissions out of three sources (mud-gas separator, flowback venting, and the dehydrator) are essentially determined by the flowback phase. It was thus possible to model only this source with a unitized emission rate (1g/s) and then actual 1-hour impacts were scaled using the total maximum emission rates.

Each year of meteorological data was modeled with the flowback vent parameters to determine the maximum 1-hour impacts for 1 g/s emission rate. These results were then reviewed and the maximum overall normalized impact of 641 µg/m³ (for Albany, 2008 data) was calculated as the worst case hourly impact. Using the total emissions from all three sources for

each of the vented toxic pollutants, as presented in Table 6.17, along with this maximum normalized impact, results in the maximum 1-hour pollutant specific values in the third column of Table 6.17. The pollutants “shaded out” in the table are not vented from these sources. All of the worst case 1-hour impacts are well below the corresponding SGCs, but the maximum 1-hour impact of $61.5 \mu\text{g}/\text{m}^3$ for H_2S (underlined top entry in the box) is above the New York standard of $14 \mu\text{g}/\text{m}^3$.

Thus, if any “sour” gas is encountered in the Marcellus Shale, there would be a potential of exceedance of the H_2S standard. The maximum 1-hour impact occurred relatively close to the stack, and, in order to alleviate the exceedance, ambient air receptors would be excluded in all areas within at least 100 m of the stack. Alternately, it is possible to also reduce this impact by using a stack height which is higher than the conservative 3.7 m (12 ft) height provided in the Industry Information Report. Iterative calculations for the year with the maximum normalized impact indicated that a minimum stack height of 9.1 m (30 ft) would be necessary to reduce the impact to the $12.1 \mu\text{g}/\text{m}^3$ value for H_2S reported in the “Max 1-hour” column of Table 6.17.

With this requirement, all venting source impacts would be below the corresponding SGCs and standard.

For the set of seven pollutants resulting from the combustion sources and the dehydrator, it was previously discussed that it was only necessary to explicitly model benzene and formaldehyde, along with the annual acetaldehyde impacts, in order to demonstrate compliance with all SGCs and AGCs for the rest of the pollutants. The relative levels of the SGCs and AGCs presented in Table 6.18 for these pollutants and the corresponding emissions in the Industry Information Report tables clearly show the adequacy of this assertion. For the modeling of these pollutants, the maximum short-term emissions were used for the 1-hour impacts, but the annual emissions were used for the AGCs comparisons. The annual emissions were determined using the same procedures as discussed above for the criteria pollutants.

An initial year of meteorological data which corresponded to the worst case conditions for the criteria pollutants was used to determine the level of these impacts relative to the SGCs and AGCs before additional calculations were made. The results of this initial model run are presented in right-hand set of columns of Table 6.17. These indicate that, while the 1-hour

impacts are an order of magnitude below the benzene and formaldehyde SGCs and the acetaldehyde AGC, there were exceedances of the AGCs for the former two pollutants (the top underlined entries for each pollutant in the maximum annual column). It was determined that these exceedances were each associated with a particular source: the glycol dehydrator for benzene and the offsite compressor for formaldehyde. It should be noted that these exceedances occur even when the emissions from dehydrator are controlled to be below the National Emissions Standard for Hazardous Air Pollutants (NESHAP) imposed emission rate provided in Table 22 of the Industry Information Report and with 90% reduction in formaldehyde emissions accounted for by the installation of an oxidation catalyst, by NESHAP Subpart JJJJ requirement for the compressor. To assure the large margin of safety in meeting the benzene and formaldehyde SGCs and the acetaldehyde AGC, another meteorological data base was used to calculate these impacts. The results in Table 6.17 did not change from these calculations. Thus, it was determined that no further modeling was necessary for these. On the other hand, for the benzene and formaldehyde AGC exceedances, a few additional model runs were performed to test potential mitigating measures. It is clear that, similar to the criteria pollutant impacts, these high annual impacts are partially due to the low stacks and the associated downwash effects for both the dehydrator and the compressor sources. Given that these two sources already need to include NESHAP control measures, the necessary additional reduction in impacts can be practically achieved by either limiting public access to about 150m from these sources, or by raising their stacks.

An iterative modeling of increased stack heights for both the dehydrator and the compressor demonstrated that in order to achieve the corresponding AGCs, the stack of the dehydrator should be a minimum of 9.1m (30ft), in which case it would also avoid building downwash effects, while the compressor stack would be raised to 7.6m (25ft). These higher stacks were then modeled using each of the 12 years of meteorological data and the resultant overall maxima, tabulated in the bottom half of the “Max annual” column in Table 6.18. It should be noted that these modifications to stack height would also reduce the corresponding 1-hour maxima leading to a larger margin of compliance with SGCs. With these stack modifications and the required NESHAP control measures, all of the SGCs and AGCs are projected to be met by the various combustion operations and the dehydrator. It should be noted that appropriate stack height for

both the compressors and any associated dehydrators can be better determined by case-specific modeling during the compressor station permitting process if the dehydrator is to be located at the compressor station.

6.5.2.5 Supplemental Modeling Assessment for Short Term PM_{2.5}, SO₂ and NO₂ Impacts and Mitigation Measures Necessary to Meet NAAQS.

As a supplement to the initial modeling, a number of additional model runs had to be made in order to address certain outstanding issues with PM₁₀ and PM_{2.5} short term impacts from the original analysis, as well as to incorporate new information provided by industry. In addition, the re-assessment also addresses EPA's promulgated 1-hour NAAQS for SO₂ and NO₂ which became effective since September 2009. The modeling performed previously for PM₁₀/PM_{2.5} was limited to a simplified set-up of the drilling and completion equipment engines and conservative set of assumptions which lead to substantial exceedances of the 24-hour NAAQS for both PM₁₀ and PM_{2.5}. Based on this preliminary result, it was deemed that further modeling would not resolve the exceedances without some level of emission mitigation.

Thus, industry was asked to provide a set of potential mitigation measures to alleviate these exceedances. In addition, the 2009 draft SGEIS identified a simple stack height and/or "fencing-in" of impacts option to be considered. This latter was not meant as the Department's suggested preferred mitigation option. Instead, the purpose behind the modeling with increased stack height was to provide a quantification of the level of simple physical adjustments to the operations in order for industry to incorporate the results in their assessment of mitigation and control measures. Based on both industry and public input, additional modeling analysis has been undertaken to address the PM₁₀ and PM_{2.5} exceedances and the associated mitigation measures necessary to assume NAAQS compliance.

In addition to the PM₁₀/PM_{2.5} issue, EPA promulgated new 1-hour standards for SO₂ and NO₂. These standards are 100 ppb (or 188 µg/m³) for NO₂, as the 3 year average of the 98th percentile of the daily maximum 1-hour values and 75 ppb (or 196 µg/m³) for SO₂, as the 3 year average of the 99th percentile of the daily maximum 1-hour values, which became effective on April 12, 2010 and August 23, 2010, respectively⁸⁹. These standards would be considered within the

⁸⁹ Federal Register: Vol 75, No. 26, pp 6474+ (2/9/10) and Vol. 75, No. 119, pp35520+ (6/22/10).

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 analysis⁹⁰. 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 PM_{2.5}, 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 memo⁹¹ on PM_{2.5}, 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 PM_{2.5} 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/m³ 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 public⁹² 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 PM_{2.5} since these are the controlling impacts; that is, any measures to eliminate the PM_{2.5} 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 $\mu\text{g}/\text{m}^3$, essentially due to the rig engine, which would still require mitigation when a background level of 15 $\mu\text{g}/\text{m}^3$ 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 PM_{2.5} 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 PM_{2.5} 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 PM_{2.5} impact is calculated to be 65ug/m³ 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 PM_{2.5} 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 PM_{2.5} case of Table 6.18 (Buffalo, 2006), the 202 µg/m³ impact reduces to 44 µg/m³ at a distance of 75m from the engines. Again, a 10% reduction in PM emissions due to 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 PM_{2.5} 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 SO₂ and NO₂ 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 µg/m³ 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) SO₂ and NO₂ 1-hour Impacts and Potential Mitigation Measures.

The 1-hour SO₂ and NO₂ 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 SO₂ and NO₂ impacts to assure that all NAAQS are met.

With respect to the 1-hour SO₂ standard of 196 µg/m³, no detailed modeling was determined necessary. Instead, the results of the previous SO₂ 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 SO₂ impacts using the ratio of the fracturing engine SO₂ and CO emissions since these engines were responsible for the overall maxima. The resultant maximum impact is calculated to be 24 µg/m³. Using a representative, yet conservative, maximum 1-hour SO₂ level of 126 µg/m³ from the Elmira monitor for 2009 gives a total impact of 150 µg/m³ which is below the corresponding NAAQS of 196 µg/m³. Thus, no further modeling was necessary to demonstrate compliance with the 1-hour SO₂ standard.

Simple scaling to demonstrate compliance was not possible for the NO₂ 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 NO₂ 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 memorandum⁹³ on June 29, 2010 which provides guidance on how to perform a first Tier assessment for the NO₂ NAAQS. More recently, EPA has provided further guidance⁹⁴ on particulars in the modeling approach for NO₂ 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 NO₂ to NO_x emissions assumed for stacks from various source types. Of these, the latter is more critical since NO₂ is a small fraction of the NO_x emissions in essentially all source types and assuming all of the NO_x emissions are NO₂ 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 NO₂. 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 NO₂ 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 NO₂ modeled impacts; the Ozone

⁹³ Guidance Concerning the Implementation of the 1-hour NO₂ 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 NO₂ 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 NO₂/NO_x ratio, hourly O₃ 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 NO₂ 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 µg/m³ and is still conservative relative to the form of the NO₂ 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 NO₂ 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 µg/m³ 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 µg/m³ 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 NO₂ to NO_x ratio is increased by the particulate trap from 0.11 to 0.35 due to the generation of NO₂ in order to oxidize and remove the particulates (see Appendix 18A). This would lead to even higher NO₂ 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 NO₂ 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 NO₂/ 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 NO₂/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 NO₂ 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 PM_{2.5}, 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 PM_{2.5} 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 NO₂ NAAQS without reductions in the NO₂ 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 NO₂/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 NO₂/ NO_x ratio set to 0.11 as noted previously. As for the completion equipment engines, the NO₂ 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 NO₂ 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 inconsistency 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 NO₂ 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 µg/m³ 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 NO₂ 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 PM_{2.5} 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 NO₂ 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 PM_{2.5} 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 NO₂ 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 PM_{2.5} and 1-hour NO₂ 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 PM_{2.5} (and PM₁₀) and the 1-hour NO₂ 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 PM_{2.5} and NO₂ 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 PM_{2.5} and the 1-hour NO₂ 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 PM_{2.5} 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 identifies 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 NO₂ 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 NO_x 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 NO_x 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 PM_{2.5} and 1-hour NO₂ 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 PM_{2.5} and 1-hour NO₂ 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 SO₂ and NO₂ 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, NO₂ and SO₂ impacts are presented in a supplemental modeling section. These results indicate the need for the imposition of certain control measures to achieve the NO₂ 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 ₂ S and other gas constituents
Engines for drilling	✓	✓	✓	✓		
Compressors for drilling	✓	✓	✓	✓	✓	
Engines for hydraulic fracturing	✓	✓	✓	✓	✓	
Line heaters	✓	✓	✓	✓	✓	
Off-site compressors	✓	✓	✓	✓	✓	
Flowback gasflaring	✓	✓	✓	✓	✓	
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 ($\mu\text{g}/\text{m}^3$)

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
PM ₁₀ NAAQS				150	50
PSD Increment				30	17
SILs				5	1
PM _{2.5} NAAQS				35	15
PSD Increment				9	4
SILs ⁹⁶				1.2	0.3
NO ₂ NAAQS	188				100
PSD Increment					25
SILs					1.0
CO NAAQS	40,000		10,000		
SILs	2000		500		

⁹⁶ The PM_{2.5} 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 ($\mu\text{g}/\text{m}^3$)	
SO ₂	Elmira* and Belleayre	3 hour - 125 Annual - 8	24-hour - 37
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			PM10		PM2.5*		CO		NO ₂
		<u>3-hour</u>	<u>24-hour</u>	<u>Annual</u>	<u>24-hour</u>	<u>Annual</u>	<u>24-hour</u>	<u>Annual</u>	<u>1-hour</u>	<u>8-hour</u>	<u>Annual</u>
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 ($\mu\text{g}/\text{m}^3$)	SIL*	Worst Case Background Level ($\mu\text{g}/\text{m}^3$)	Total ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)	Increment Impact** ($\mu\text{g}/\text{m}^3$)	PSD* Increment ($\mu\text{g}/\text{m}^3$)
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 NO₂ 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 ($\mu\text{g}/\text{m}^3$)		All Combustion Sources and Dehydrator Impacts ($\mu\text{g}/\text{m}^3$)			
		<u>Max 1-hr</u>	<u>SGC</u>	<u>Max 1-hr</u>	<u>SGC</u>	<u>Annual</u>	<u>AGC</u>
Benzene***	0.218	140	1,300	13.2	1,300	$\frac{0.90}{0.10}$	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 ₂ S***	0.096	$\frac{61.5}{12.1}$	14*				
Formaldehyde**				4.4	30	$\frac{0.20}{0.04}$	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 H₂S

** 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 H₂S 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 NO₂ (New July 2011)

Met Data Location	Met Data Year	PM10, 24-hr ($\mu\text{g}/\text{m}^3$)		PM2.5, 24-hr ($\mu\text{g}/\text{m}^3$)		NO ₂ , 1-hour impact ($\mu\text{g}/\text{m}^3$) (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 ($\mu\text{g}/\text{m}^3$)		339	106	202	59	213	272	231
Max @ 75m ($\mu\text{g}/\text{m}^3$)		92	75	44	30	100-140	140-170	120-150
Max Dist to NAAQS - Background (m)		60	60	150	120	<90	<100	<100

NOTE: NO₂ 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

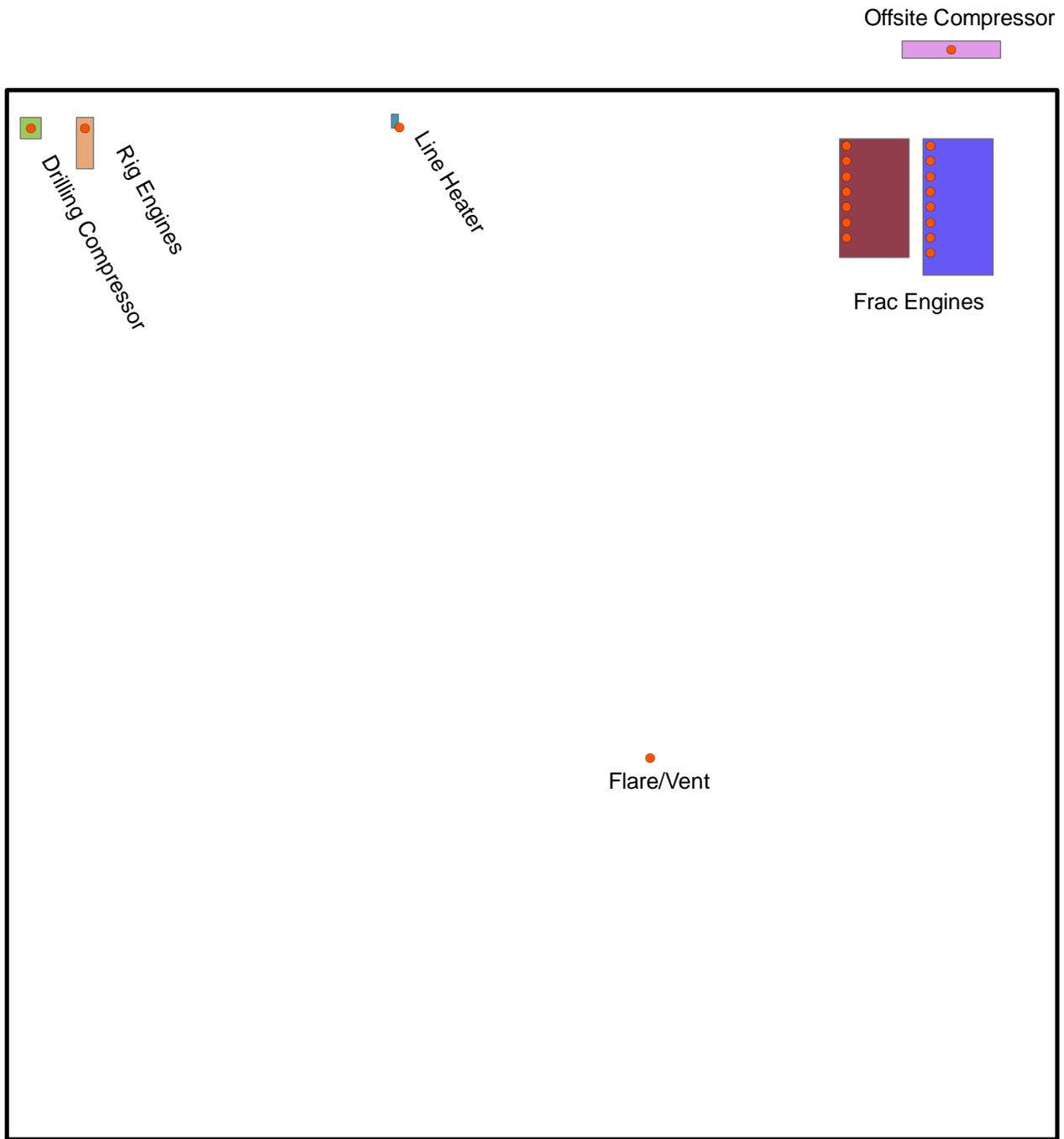


Figure 6.10- Location of Well Pad Sources of Air Pollution Used in Modeling

Buildings

-  Drilling Compressor
-  Frac Engines1
-  Frac Engines2
-  Line Heater
-  Offsite Compressor
-  Rig Engines



6.5.3 Regional Emissions of O₃ Precursors and Their Effects on Attainment Status in the SIP

This section addresses a remaining issue, as stressed by EPA Region 2⁹⁷ that the initial analysis did not provide a quantitative discussion of the potential regional emissions of the O₃ 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 O₃ 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 PM_{2.5} national ambient air quality standards (NAAQS) of 15 and 35 µg/m³, 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 O₃ and PM_{2.5}, 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, NO₂ and SO₂. EPA has recently promulgated revisions to the lead, SO₂ and NO₂ NAAQS and has established new monitoring requirements for the lead and NO₂ NAAQS, as well as new modeling requirements for the SO₂ 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 NO₂ 1-hour NAAQS and would have to submit a recommendation to EPA on SO₂ 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 O₃, 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 O₃ 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 O₃ and PM_{2.5} 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. PM_{2.5}, 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 O₃ 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

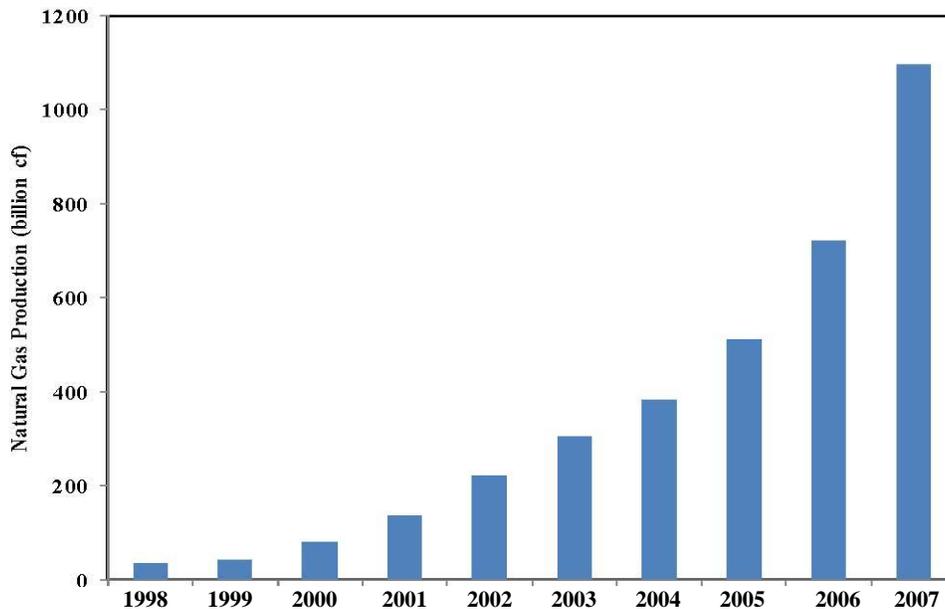
In order to assist the Department to develop a full understanding of the cumulative and regional emissions and impacts of developing the gas resources of the Marcellus Shale, available information from similar activities in other areas of the country has been reviewed. Notably, certain information from 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, 1998-2007⁹⁸



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 standard⁹⁹. 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 PM_{2.5} 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 PM_{2.5} 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 report¹⁰¹ 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 Sources¹⁰³

Source	2007 Pollutants, Tons per day(Tpd)		2009 Pollutants, Tons per day (Tpd)	
	NO _x	VOC	NO _x	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 O₃ 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 O₃ NAAQS and potential revisions to the PM_{2.5} 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 O₃ 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 O₃ 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 PM_{2.5} 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 TCEQ¹⁰⁴ and the PADEP¹⁰⁵ 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 O₃ and PM_{2.5} 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 O₃ 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 ₂ S 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.
<p><u>Regional scale</u> O₃, PM_{2.5}, NO₂ and add toxics.</p>	<p>To assess the impact of regional VOC and NO_x emissions on Ozone and PM_{2.5} levels.</p>	<p>Add a Department monitoring trailer to a new site in Binghamton, plus add toxics at existing Pinnacle site and the new site.</p>
<p><u>Local/near field</u> monitoring for BTEX, methane, formaldehyde, sulfur (plus O₃, PM_{2.5} and NO₂)</p>	<p>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.</p>	<p>Purpose-built vehicle with generators as a <u>mobile</u> laboratory. A less desirable alternative is a “stationary” trailer which would need days for initialization.</p>
<p>Intermittent methane and VOC leaks from sources (e.g. fugitive)</p>	<p>To detect and initiate company mitigation of fugitive leaks.</p>	<p>Forward Looking Infrared (FLIR) cameras- one for routine inspections, second to respond to complaints.</p>
<p>“Saturated” BTEX and other VOC species monitoring</p>	<p>To verify the spatial extent of the mobile monitoring results.</p>	<p>Manually operated canister samplers which can be analyzed for 1 to 24-hour concentrations of various toxics.</p>

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 CO₂, and other relative GHGs, as both short tons and as carbon dioxide equivalents (CO₂e) 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 CO₂ is the second-most important one.¹⁰⁸

Human activities result in emissions of four principal GHGs: CO₂, methane (CH₄), nitrous oxide (N₂O) 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, CO₂ is released to the air. Other processes generate CH₄, N₂O and halocarbons and other GHGs that are less abundant than CO₂, 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 CO₂ and CH₄ 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 CO₂ - and, to a lesser extent, CH₄ and N₂O - since these gases are produced through combustion. Both CH₄ and CO₂ 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 N₂O produced through combustion are quite small compared to the amount of CO₂ produced, CO₂ and CH₄ 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 CH₄ 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 CH₄ emissions in the United States and the second largest human-made source of CH₄ 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 CH₄ 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, CH₄, and N₂O 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 CO₂ 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 CH₄. Overall, CH₄ and N₂O emissions from combustion sources are significantly less than CO₂ 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 CH₄ 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 CH₄ in many gaseous streams, as well as the presence of CO₂ in some streams. However, relative to combustion and process emissions, fugitive CH₄ and CO₂ contributions are insignificant.¹¹⁵

6.6.3 Emissions Source Characterization

Emissions of CO₂ and CH₄ 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 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 Production¹¹⁹

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 CO₂ 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 CO₂ and/or CH₄ 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 CO₂ and/or CH₄ 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 CO₂), is the preferred technique for estimating CO₂ 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 CO₂ 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 CO₂ emissions from the mobile

¹²¹ API, 2004; amended 2005., p. 4-3.

sources. A sample calculation showing this methodology for determining combustion emissions (CO₂) from mobile sources is included as Appendix 19, Part B.

Carbon dioxide and CH₄ 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 CO₂ and 4.1 tons of CH₄ 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 vehicle 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 CO₂ emissions. Small quantities of CH₄ and N₂O 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 (CO₂, HC, CO, NO_x, particulate matter, and toxics) for gasoline and diesel fueled vehicles. The preferred approach for estimating CH₄ and N₂O emissions from mobile sources is to assume that these emissions are negligible compared to CO₂.¹²³

An alternative to using modeling software for determining CO₂ 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 CO₂ emissions from mobile sources related to the subject activity. A sample CO₂ emissions calculation using fuel consumption is shown in Appendix 19, Part B. Table GHG-2 in Appendix 19, Part A includes CO₂ 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 CO₂ 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 CO₂ 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 CO₂ emission estimates for transporting the completion rig to and from the wellsite. As shown in the table, approximately 4 tons of CO₂ emissions may be generated from a mobilization of the completion rig. For simplification, transportation 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 CO₂ emissions generated by these stationary sources. As shown in the table, approximately 83 tons of CO₂ emissions per single vertical well would be generated as a result of drilling operations. Tables GHG-5 and GHG-6 show CO₂ 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 CO₂ and/or CH₄. Tables GHG-7, GHG-8 and GHG-9 in Appendix 19, Part A include estimates of individual and total emissions of CO₂ and CH₄ 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 CO₂ 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 CO₂ from transportation provided in the tables rely on estimated fuel usage for both light and heavy trucks. A sample calculation for determining CO₂ emissions based on fuel usage is shown in Appendix 19, Part B. As shown in Table GHG-7, transportation related completion-phase emissions of CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ and 12 tons of CH₄ 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 CH₄ emissions during flaring result from 2% of the gas flow remaining uncombusted. ICF computed the primary CO₂ and CH₄ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ emissions 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 CO₂ emissions. Transportation estimates were used to determine CO₂ 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 CO₂ and CH₄ 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 CO₂ and CH₄ 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 CO₂ and CH₄ 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 CH₄ 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 CO₂ emissions while compression of the natural gas generates CH₄ 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 CO₂ and CH₄ 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 CH₄ emissions during the this phase, while operation of pneumatic device vents also generates vented CH₄ emissions. The amount of CH₄ 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 CO₂ and CH₄ 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 CO₂, and other relative GHGs, as both short tons and CO₂e 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 CO₂e, 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 CO₂ 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 CO₂ has a GWP of 1 and CH₄ has a GWP of 23, and that this comparison allows emissions of greenhouse gases to be estimated and reported on an equal basis as CO₂e.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 CO₂e. Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part A include a summary of estimated CO₂ and CH₄ emissions from the various operational phases as both short tons and as CO₂e expressed in short tons.

Table 6.27 - Global Warming Potential for Given Time Horizon¹³⁰

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 CO₂ and CH₄ 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 CO₂e 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 CH₄ 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 CH₄ emitted is equivalent to 25 tons of CO₂. Thus, because of its recurring nature, the importance of limiting CH₄ 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 ₂ e (tons) ¹³¹	Total Emissions from Proposed Activity CO ₂ e (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 CH₄ (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 CO₂ and CH₄ 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 CH₄.

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 Considerations¹³³

Types of Approaches	General Considerations
Published emission factors	<ul style="list-style-type: none"> · 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., CO₂, CH₄, and N₂O)
Equipment manufacturer emission factors	<ul style="list-style-type: none"> · 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	<ul style="list-style-type: none"> · Accuracy depends on simplifying assumptions that may be contained within the calculation methods · May require detailed data
Process simulation or other computer modeling	<ul style="list-style-type: none"> · 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	<ul style="list-style-type: none"> · 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	<ul style="list-style-type: none"> · 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
<p>Footnotes and Sources:</p> <p>^a Continuous emissions monitoring applies broadly to most types of air emissions, but may not be directly applicable nor highly reliable for GHG emissions.</p> <p>^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.</p>	

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 Impacts¹³⁴

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)

Scenario	Total Employment (in number of FTE jobs)	
	Low	Average
Direct Employment Impacts		
Construction Employment ¹	4,408	17,634
Production Employment ²	1,790	7,161
Indirect Employment³	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.

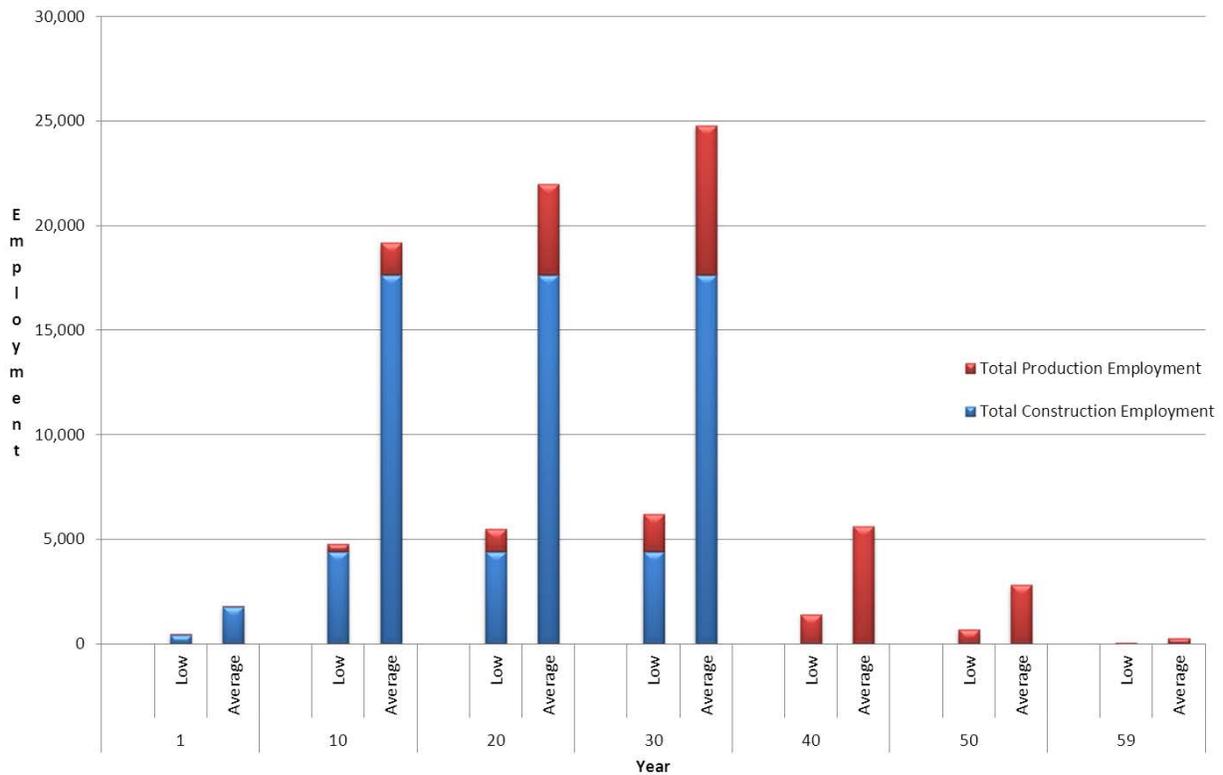
¹ These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

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)

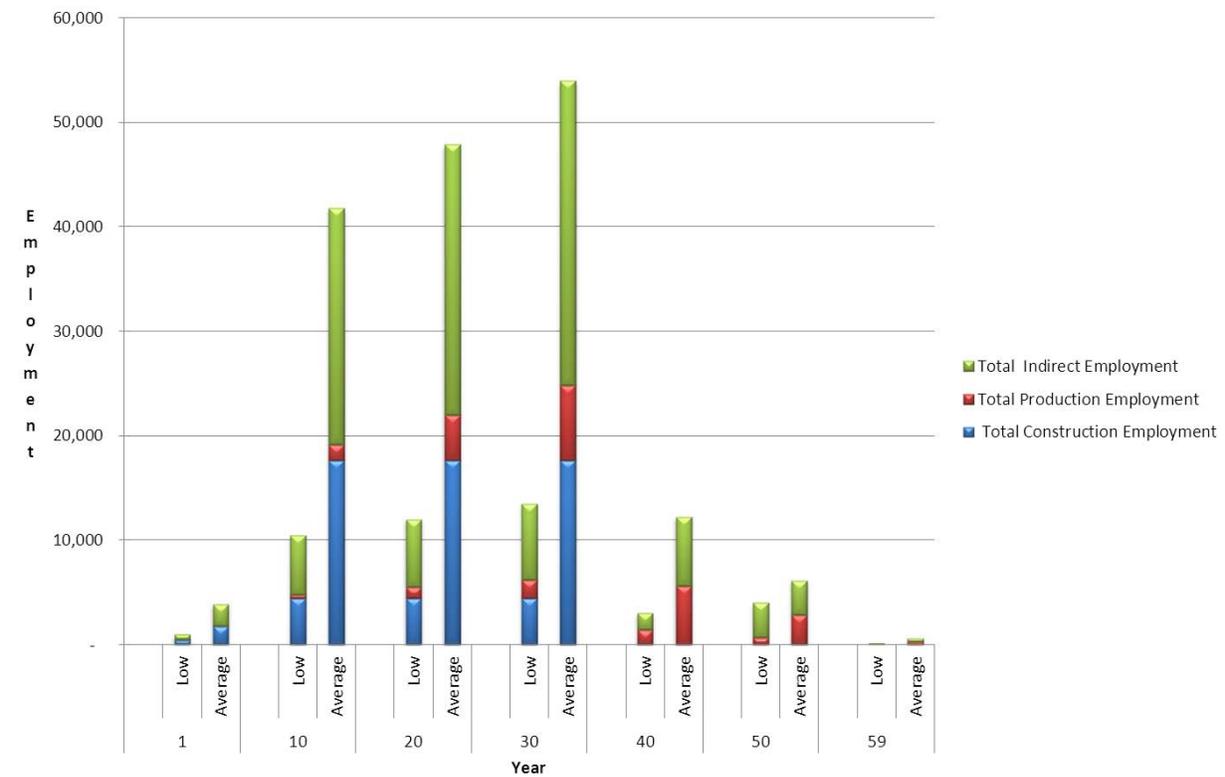


In addition to the direct employment impacts described above, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies 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)

Scenario	Total Employee Earnings (\$ millions)	
	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)

Scenario	Total Employment (in number of FTE jobs)	
	Low	Average
Region A		
Direct Employment Impacts		
Construction Employment ¹	2,204	8,818
Production Employment ²	895	3,581
Indirect Employment Impacts³	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 Impacts³	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 Impacts³	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)

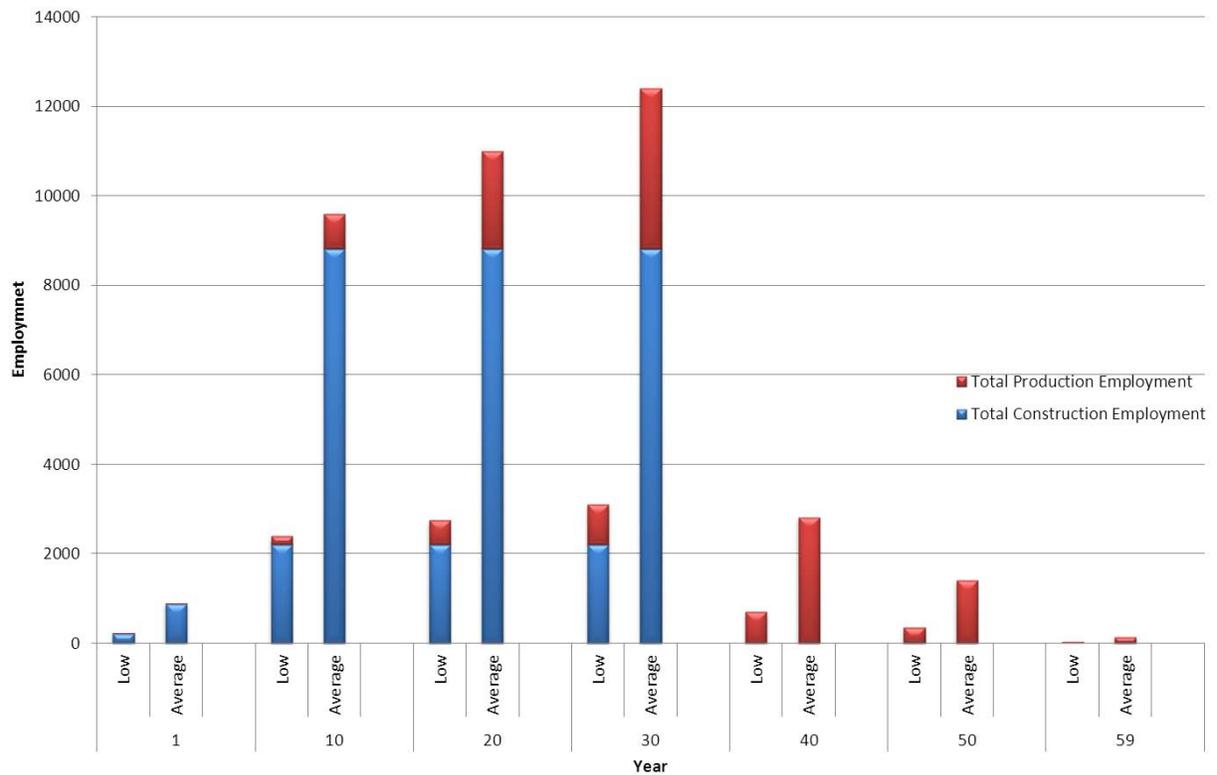


Figure 6.15 - Projected Direct Employment in Region B Resulting from Each Development Scenario (New August 2011)

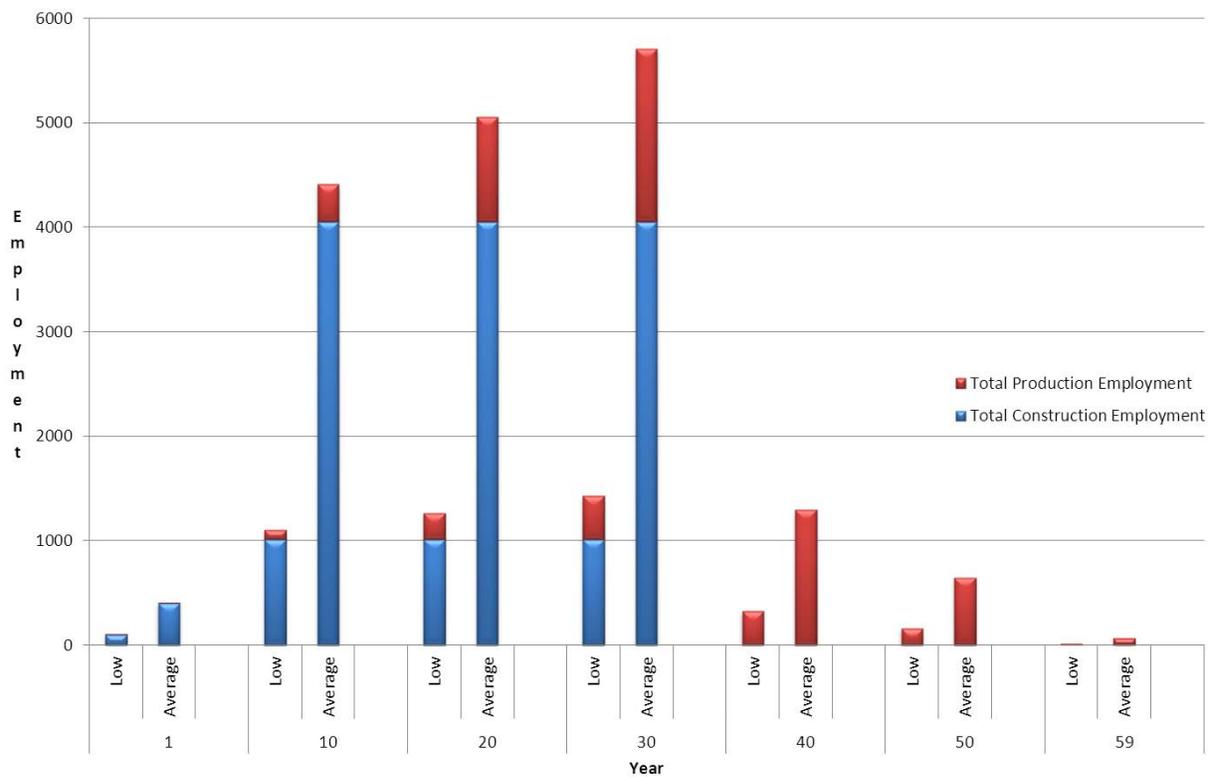
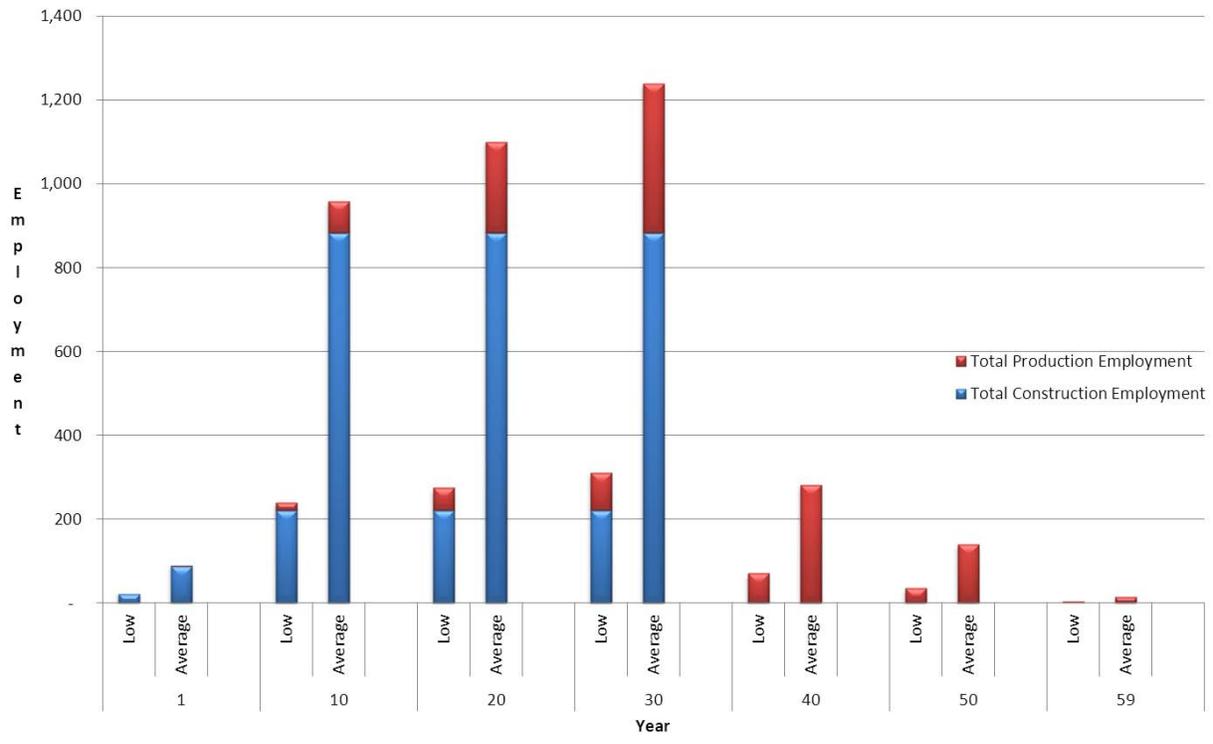


Figure 6.16 - Projected Direct Employment in Region C Resulting from Each Development Scenario (New August 2011)



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)

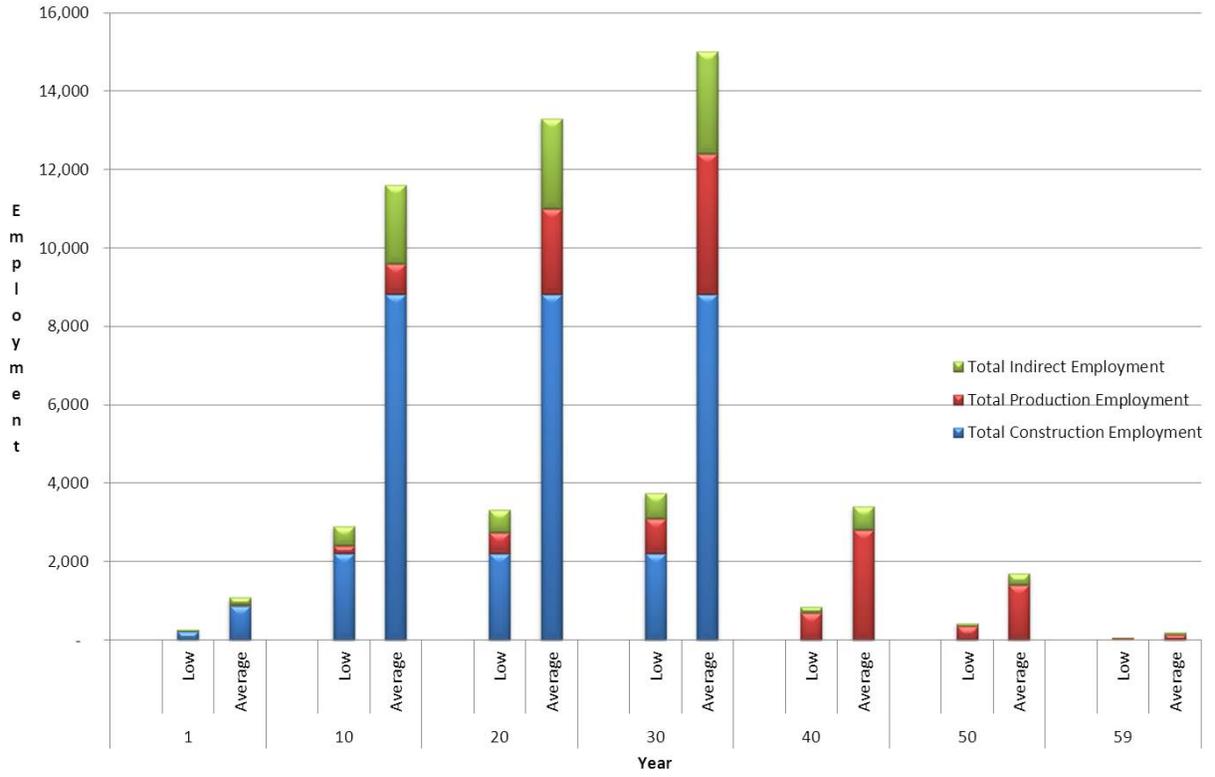


Figure 6.18 - Projected Total Employment in Region B Under Each Development Scenario (New August 2011)

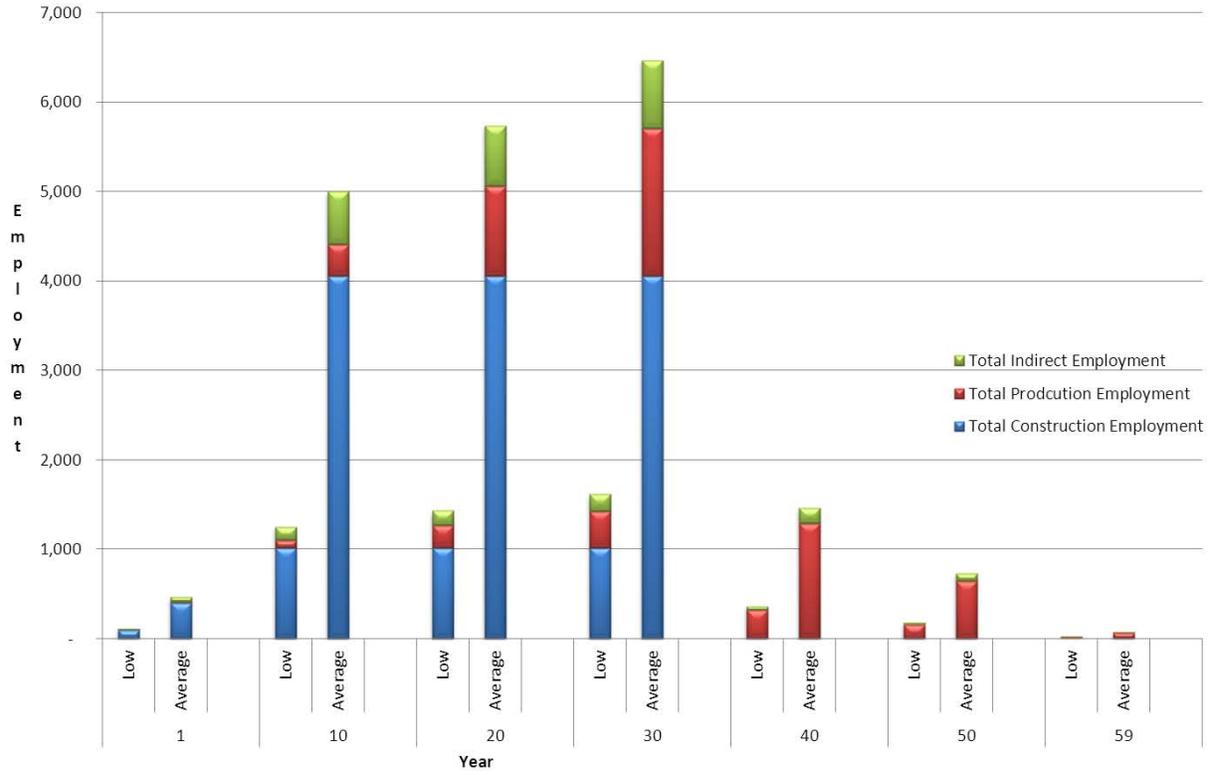
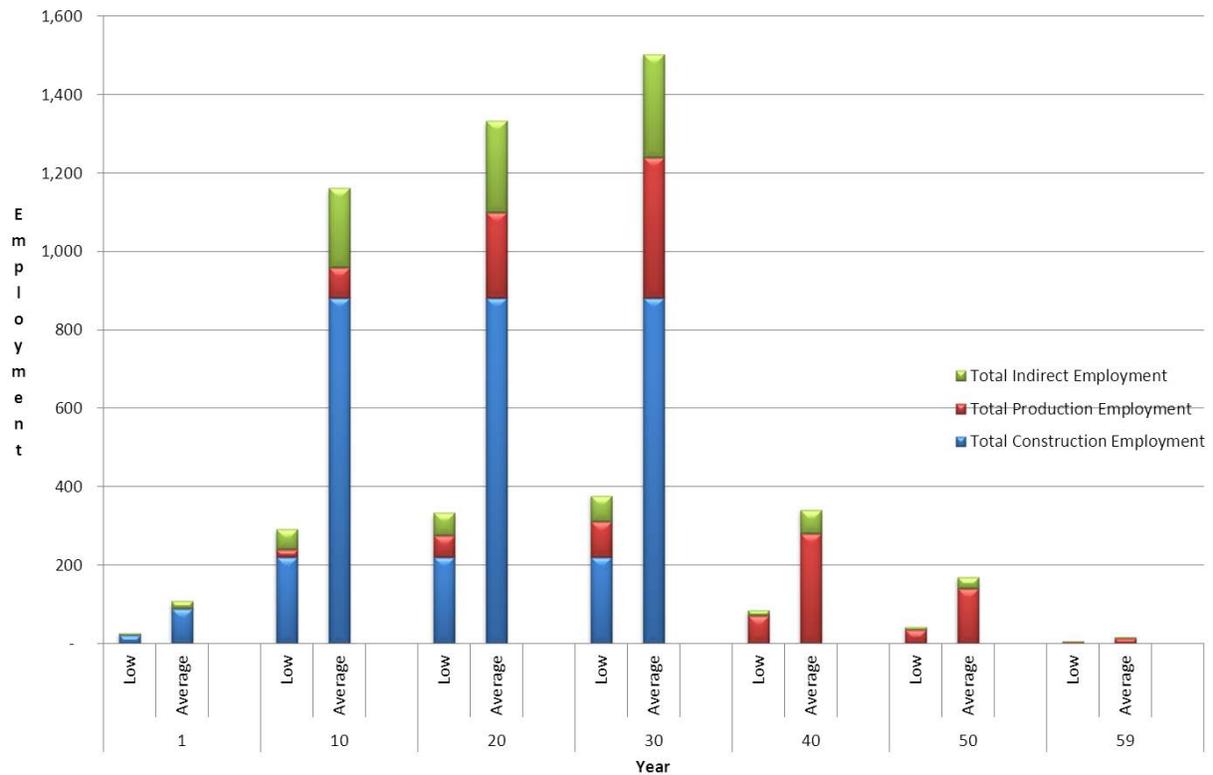


Figure 6.19 - Projected Total Employment in Region C Under Each Development Scenario (New August 2011)



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)

Scenario	Employee Earnings (\$ millions)	
	Low	Average
Region A		
Direct Employment Impacts		
Construction Earnings ¹	\$149.2	\$597.0
Production Earnings ²	\$60.6	
Indirect Earnings Impacts³	\$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 Impacts³	\$12.9	\$51.6

Scenario	Employee Earnings (\$ millions)	
	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 Impacts³	\$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 inhabited 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)

Year	Low Scenario			Average Scenario		
	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)

Production Year	Development Scenario	Transient Population	Permanent Population		
		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)

Year	Low Scenario			Average Scenario		
	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)

Year	Low Scenario			Average Scenario		
	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)

Year	Low Scenario			Average Scenario		
	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 28,447 persons 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.

Because natural gas wells would not be evenly distributed across the regions, there may be more significant localized population impacts. Depending on the distribution of the wells and the phasing of well development, which depends partly on the price of natural gas, shale gas production may create localized growth in individual small towns. Also, because the development of new wells would not be distributed evenly over time due to swings in well development activity, downswings may cause periods of smaller-than-projected population impacts, while upswings may cause larger-than-projected population impacts.

6.8.3 Housing

This section describes the potential impacts on housing resources and property values that could result from the development of natural gas reserves in low-permeability shale in New York State. Statewide and regional impacts are discussed separately in the following section. For the purposes of this analysis, three representative regions were selected to examine the range of potential regional impacts. This analysis in no way is meant to imply that impacts would occur only in these three regions. Local- and regional-level impacts would occur wherever high-volume hydraulic fracturing wells are constructed. Currently, the actual locations of these wells have not yet been determined, and wells could be sited anywhere there is low-permeability shale. As described in previous sections, two development scenarios were analyzed for a 60-year period. Only the impacts that would occur during maximum build-out conditions (Year 10 for the transient workers and Year 30 for the permanent workers) are presented in this SGEIS. Impacts for all other years are presented in the Economic Assessment Report.

6.8.3.1 New York State

As previously described in Section 6.8.1 (Economy, Employment, and Income), total construction employment in New York State that would result from the development of low-permeability natural gas reserves is projected to range from 4,408 new workers under the low development scenario to 17,634 new workers under the average development scenario. Initially, the majority of the construction workers are assumed to be temporary, transient workers. As the natural gas fields are developed over time, it is assumed that an increasing number of these workers would become permanent residents. Production employment is projected to range from 1,790 workers under the low development scenario to 7,161 workers under the average development scenario.

Table 6.44 presents estimates of the maximum temporary, transient employment that would occur in Year 10 and the maximum permanent employment that would occur in Year 30. Transient employment includes those construction workers who would only temporarily relocate to the area during well construction. Permanent employment includes permanent construction workers and permanent production workers, as discussed more fully in Section 6.8.2, Population.

Table 6.44 - Maximum¹ Estimated Employment by Development Scenario for New York State (New August 2011)

Development Scenario	Transient Employment (FTE)	Permanent ² Employment (FTE)
Low	2,409	5,757
Average	9,639	23,032

¹ Maximum transient employment occurs in Year 10, while maximum permanent employment occurs in Year 30.

² Permanent employment includes both permanent construction and production employment.

Note: Maximum transient employment and maximum permanent employment are reached in two different years. Therefore, the figures for transient employment and permanent employment in this table cannot be added to equal total employment. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for year-by-year employment details.

Temporary Housing

The construction phase is expected to have a short-term impact on temporary housing resources in New York State. New York State is currently not a major oil or gas producing state and, therefore, does not have a large work force skilled in oil and natural gas extraction. Thus, it is anticipated that workers specialized in gas exploration and drilling would travel into New York from other states where gas exploration and drilling is more significant. In the beginning, much of the workforce would need to be imported from other states. Over time, an experienced workforce would be created within New York, and the need for out-of-state workers would decline.

Typically, construction of a high-volume hydraulic fracturing well is completed in 3 to 4 months. Therefore, the transient workers needed to drill these wells would likely only temporarily relocate to a specific area, and once that well was completed they would move on to another site. The influx of workers who would move from one well development site to another would increase the demand for transient housing, such as rental properties and hotel/motel rooms, thereby decreasing the rental and hotel/motel vacancy rates within the state. Decreased rental

and hotel/motel vacancy rates would provide short-term economic benefits to some owners of rental housing and hotels/motels within the state and in certain areas may increase prices charged for these temporary housing units.

Table 6.45 identifies the total stock of rental housing units, the existing supply of vacant housing units for rent, and the rental vacancy rate in New York State as a whole. Assuming a worst-case scenario where each projected transient construction worker would require one rental-housing unit, New York State as a whole could easily supply rental housing to construction workers under all development scenarios with existing vacant units at maximum build-out. Therefore, the impact on the supply of rental housing resources during the construction phase would be negligible at the statewide level. Impacts at the regional and local levels are discussed below.

Table 6.45 - New York State Rental Housing Stock (2010) (New August 2011)

Total Rental Inventory	For Rent	Rental Vacancy Rate (%)
3,632,743	200,039	5.5

Source: USCB 2010.

Permanent Housing

Some migration of workers into New York State would be expected to occur as a result of the construction and production phase of the high-volume hydraulic fracturing operations. Initially, there would not be enough workers specialized in gas production to meet the demand. Therefore, it would be expected that these workers would move into New York State from states where the natural gas extraction industry is more developed. However, over time, an experienced workforce would be created within the state, and the need for out-of-state workers would decline.

Table 6.46 identifies the existing supply of vacant housing units for sale or rent in New York State. Seasonal, recreational, and occasional-use units and units rented or sold but not occupied were not included in these totals. Assuming a worst-case scenario at maximum build-out, it is anticipated that each projected permanent construction and production worker would require one permanent housing unit. Given that assumption, New York State has more than enough houses

for sale to provide permanent housing units to the new permanent workers. Therefore, the impact on the supply of permanent housing units would be negligible at the statewide level.

Table 6.46 - Availability of Owner-Occupied Housing Units (2010) (New August 2011)

Total Number of Housing Units	For Sale	For Rent
8,108,103	77,225	200,039

Source: USCB 2010.

Based on the above discussion, it can be concluded that at the statewide level, New York State as a whole has a more than sufficient supply of rental properties and housing units to cope with the additional workers employed under each of the development scenarios at maximum build-out in Year 30. Regional and local impacts are discussed below.

6.8.3.2 Representative Regions

Table 6.47 identifies the maximum transient and permanent employment in Regions A, B, and C. See Section 6.8.1 and 6.8.2 for a detailed discussion of the derivation of these numbers.

Table 6.47 - Maximum Transient and Permanent Employment by Development Scenario and Region (New August 2011)

Region	Maximum Transient Employment (in FTE)¹	Maximum Permanent Employment²
Region A		
Low	1,205	2,879
Average	4,820	11,517
Region B		
Low	554	1,325
Average	2,217	5,297
Region C		
Low	121	289
Average	482	1,152

¹ Maximum transient employment occurs in Year 10.

² Maximum permanent employment occurs in Year 30 and includes both permanent construction and production employment.

Note: Maximum transient employment and maximum permanent employment are reached in two different years. Therefore, the figures for transient employment and permanent employment in this table cannot be added to equal total employment. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report, for year-by-year employment details.

Temporary Housing

The construction phase would be expected to have a short-term, mixed impact on the rental housing stock in the representative regions. As described above, given the short-term nature of well construction, it is unlikely that many of the construction workers would initially permanently relocate to the region. However, as the natural gas development industry developed in the region and long-term employment became more likely, more construction workers would choose to permanently relocate to the regions.

In most cases, transient construction workers would temporarily reside in nearby population centers and commute to the development sites. Once the well is completed, they would move on to another area. The influx of a large number of transient construction workers into these regions would be expected to increase the demand for temporary housing, such as rental properties, hotel/motel rooms, and RV camp sites, thereby decreasing rental and hotel/motel vacancy rates throughout the region. Decreased rental and hotel/motel vacancy rates are expected to provide short-term economic benefits to some owners of rental housing and hotels/motels in these regions, but it could also cause a shortage of temporary housing in the most affected areas. The increase in demand may also increase the price charged for these units.

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 campsites 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).

The impacts on temporary housing described above for Bradford County, while acute in the short-term, may decline in the long-term as more workers establish permanent residences in the area and as the market has time to respond to the shortage in temporary housing. As more

hotel/motel rooms are constructed, and more rental properties become available, the shortages of existing units would decline and subsequently rental prices would also decline.

As with the situation in areas in Pennsylvania undergoing early Marcellus shale development, it is likely that most of the workers employed during the construction phase would relocate from outside of Regions A, B, and C, as natural gas well exploration and drilling require specialized skilled workers (Marcellus Shale Education and Training Center 2009).

Table 6.48 identifies the total rental inventory, the existing supply of vacant housing units for rent, the rental vacancy rate, and the number of hotel/motel rooms in Regions A, B, and C.

Assuming a worst-case scenario, where each incoming temporary worker would require one rental housing unit or hotel/motel room at maximum transient employment levels (Year 10),

Regions B and C have more vacant rental units than incoming workers under both scenarios.

Region A also has more hotel/motel rooms and vacant rental units than the number of incoming workers under both development scenarios. However, the average development scenario would utilize the majority (69.5%) of the rental properties and hotel/motel rooms in Region A, thereby, causing shortages for the existing renters/ hotel users.

Table 6.48 - Availability of Rental Housing Units (New August 2011)

Region	Total Rental Inventory	For Rent	Rental Vacancy Rate (%)	Hotel/Motel Rooms
Region A	48,955	3,824	7.8	3,110
Region B	24,558	2,604	10.6	3,705
Region C	29,127	2,624	9.0	1,987

Source: USCB 2009.

In Regions B and C under both development scenarios and in Regions A under the low development scenario, the existing stock of rental housing is sufficient to meet the needs of incoming workers; thus, no additional rental housing would need to be constructed. However, rent increases caused by the increased demand for rental housing could make such housing unaffordable for existing low-income tenants, and increased demand for hotel/motel rooms would be likely to cause price increases in these sectors.

Under the average development scenario, shortages of rental housing would likely occur in Region A. The use of seasonal, recreational, or occasional use housing units as rental properties could potentially reduce the impact of increased demand on rental housing in these regions. However, it is likely that rents and hotel/motel room rates would remain elevated until additional rental housing and motels/hotels were constructed to meet the higher level of demand. The higher rents would negatively impact existing low-income residents, who may not be able to find affordable rental housing within the regions. The higher motel/hotel rates and/or the fewer available rooms may discourage some visitors from coming to these regions and thereby have the potential to reduce tourism in those areas.

The above analysis was completed on a regional level and included all rental units in a two- or three-county area. However, temporary housing impacts may occur and be more severe at an even more local level. If several well pads were developed at the same the time in the same area, there would be an even larger concentration of workers and a greater demand for temporary housing in that immediate area and in the population centers located near the general vicinity of the development. Although data on commuting patterns by occupation show that temporary construction workers typically are willing to commute farther than other workers, there still could be a significant increase in local housing demand. Therefore, the localized impacts in areas where there is a high concentration of natural gas wells may be greater than those described above.

Permanent Housing

The permanent construction and production workers are expected to have a long-term, mixed impact on the permanent housing stock in the representative regions. Given the need to have natural gas operators with specialized skills, many of the production workers would relocate from areas outside the representative regions. New production workers recruited from outside the region would typically be offered permanent employment and would likely require permanent housing. In addition, as the natural gas industry expands in the representative regions and the long-term construction employment becomes more permanent in the region, more construction workers would choose to live permanently in the regions and simply commute between well sites. These additional construction and production workers would increase the demand for permanent housing. In addition, the increased economic activity that would take

place in these regions as a result of natural gas development would further increase the demand for permanent housing and reduce homeowner and rental vacancy rates in the region.

Table 6.49 identifies the number of vacant permanent housing units for sale or rent in Regions A, B, and C. Seasonal, recreational, and occasional-use units and units rented or sold but not occupied were not included in this table. The following analysis assumes a worst-case scenario where all new permanent construction workers and all production workers would relocate to the region and require one permanent housing unit each at maximum build-out (Year 30) to purchase or rent. However, in actuality this may overstate the regional impacts. Many of the permanent worker positions could be filled by currently unemployed or underemployed workers from the local areas, thus reducing the overall demand for permanent housing.

Given this worse-case assumption, Regions A, B, and C would be able to absorb the additional demand for permanent housing units under the low development scenario. Regions A, B, and C would not be able to meet the increased demand for permanent housing units under the average development scenario.

Table 6.49 - Availability of Housing Units (New August 2011)

Region	Total Number of Housing Units	For Sale	For Rent
Region A	151,135	1,516	3,824
Region B	111,185	1,989	2,604
Region C	108,031	1,278	2,624

Source: USCB 2010.

No additions to the permanent housing stock would be required under the low development scenarios in which regions could absorb additional demand for permanent housing. However, it is expected that house prices would rise initially in response to the increased demand for permanent housing, resulting in difficulties for low-income residents seeking to buy a home and capital gains for owners of existing homes. In the long-term, additional housing construction would take place and prices would level off as the supply of housing units caught up with the demand for these units.

Under the average development scenario in which regions do not have enough homes for sale or rent to meet the potential demand from incoming permanent workers, the incoming workers and existing residents would compete for the existing stock of permanent housing units, resulting in an increase in housing prices. Over time, builders and landowners would respond to the higher prices by constructing more permanent housing units. However, before such homes are constructed, a period of particularly high prices would be expected. Low-income residents that do not already own property or currently rent might face difficulties in finding affordable homes to buy, and owners of existing homes would experience capital gains.

The above analysis was completed on a regional level and included all permanent housing units in a two- or three-county area. Permanent housing impacts may occur and be more severe on a more local level. If, for example, production workers are expected to report to only a few centralized facilities, the demand for permanent housing near these facilities would be greater than for the region as a whole. This may place a strain on the permanent housing stock in such areas, and the impacts may be even greater than those described above.

6.8.3.3 Cyclical Nature of the Natural Gas Industry

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 area 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 upswings may exacerbate housing shortages within the regions.

6.8.3.4 Property Values

At this level of analysis, it is impossible to predict the actual impacts of developing the Marcellus and Utica shale natural gas reserves on individual property values. However, some

predictions can be made with regard to the general impact of mineral rights on property values and the impact of well development on adjacent properties.

Significant increases in property value are expected where the subsurface mineral rights and land are held jointly with land ownership and the exploitation of the subsurface resources is not limited in some way. Because the owners of subsurface mineral rights typically receive royalty payments equal to or greater than 12.5% of the total value of production, the development of natural gas reserves would be expected to substantially increase the value of their property. Properties where the mineral rights are not held jointly with land ownership, or where there is some restriction on drilling, would not experience this increase in value.

Property values could also be affected by the impacts associated with developing natural gas resources. 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. Once wells are in place, the local impacts would be less and there would be much less traffic moving to and from the wells. Pipelines would be constructed to carry the natural gas from the wells. Construction of the pipelines would have an impact on the landscape and would result in the maintenance of cleared rights-of-way once the pipeline is in place. Gas compressor stations would also be constructed to maintain the pressure of the gas in the pipelines, and there would be noise and air emissions associated with their operation.

It is possible that these various impacts, particularly those associated with the construction phase, could reduce the value of properties close to the wells relative to similar properties not located close to wells. In order to assess the potential impact these negative externalities would have on property values in the affected regions, a review of economic literature was undertaken. A number of studies have been conducted to provide quantitative estimates of the impact of wells on property values. These studies are discussed and reviewed below. As with much economic and econometric literature, the following studies are based on data gathered for specific geographical locations at specific times. While the findings of these studies are analogous to the current situation discussed in this SGEIS, the findings should only be used as an indication of direction and the magnitude of possible impacts on property values. Characteristics of individual housing markets and the nature of the gas development activities would vary dramatically from

site to site, thus the findings in the following reports should not be viewed as an actual estimate of impacts. BBC Research and Consulting (2001) examined the impact of coal bed methane wells on property values in La Plata County, Colorado, between 1989 and the first half of 2000. The authors used a hedonic approach (i.e., an approach that links property values to their attributes and the attributes of surrounding areas) to estimate the impact of having a well on a property and having a well near to, but not on, a property. The 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. The authors attributed the positive impact on property values of having a well located within 550 feet of a property to the prevention of further gas well development in that area due to a spacing order and setback conditions that prevented well drilling close to existing wells (BBC Research and Consulting 2001).

Boxall, Chan, and McMillan (2005) examined the impact of small to medium size oil and gas production facilities on rural residential property values using data from central Alberta, Canada. In this study, the authors found a statistically significant negative relationship between property values and the presence of oil and gas facilities within approximately of 2.5 miles of rural residential properties. The presence of oil and gas facilities within 2.5 miles of rural residential properties was estimated to reduce property values between 4% and 8%, with the potential to double the impact, depending on the level and composition of the nearby industry activities (Boxall et al. 2005).

Integra Realty Resources (2011) conducted a study of the impact of natural gas wells on property values in and around Flower Mound, a community approximately 28 miles northwest of downtown Dallas, Texas, where gas drilling is a recent development. The authors used four methods to estimate the impact of wells on property values: (1) examining the relationship between distance to a well site and property values; (2) comparing the sales prices of properties close to a well and comparable properties not close to a well; (3) a statistical analysis of the relationship between property attributes, including proximity to a well and values; and (4) surveying market participants (principally realty agents). With regard to the relationship between the distance between properties and well sites, they found that within Flower Mound

itself there was a negative impact on property values when houses are immediately adjacent to well sites; however, this negative impact diminishes quickly with increasing distance from the well. The impact was found to be between -2% and -7% of property values. The results of the comparable sales analysis indicated that, in most cases, there was little correlation between proximity to a well site and property values. However, within Flower Mound itself and for properties in excess of \$250,000 in selling price, proximity to a well had a negative impact of between -3% and -14% on property values. The statistical analysis found no statistically significant relationship between property values and proximity to a well site. Finally, market participants reported that proximity to a well site had an impact on the time required to sell a property; however, this impact was most pronounced during the actual process of well development and diminished thereafter (Integra Realty Resources 2011).

Fruits (2005) studied the impact of the South Mist Pipeline Extension on residential property values in Clackamas and Washington counties, Oregon. In his analysis, Fruits performed three statistical tests using the hedonic housing price approach and found no statistically significant impact from natural gas pipeline development on residential property values (Fruits 2005).

Palmer (2008) also looked at the impact of the South Mist Pipeline Extension on residential property values in Clackamas and Washington counties, Oregon. Palmer, working on behalf of Palomar Gas Transmission LLC, conducted a market study using data from 2004 to 2008 that compared sales of properties along pipeline corridors with comparable sales of non-affected properties. Palmer found no measurable impact on property values resulting from the construction and operation of natural gas pipelines (Palmer 2008).

In conclusion, the above literature review suggests that being in proximity to a well could reduce the value of a property, but that proximity to a gas pipeline might not reduce the value of a property. The proposed natural gas development would have an overall regional effect of increasing property values due to the expected in-migration of construction and operations workers and the increased economic activity that would occur in the area. Likewise, properties that still included unexploited sub-surface mineral rights would increase in value due to the potential of receiving royalty payments. However, 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.

6.8.4 Government Revenue and Expenditures

This section discusses the potential fiscal impacts on state and local government entities that would occur as a result of the proposed development of low-permeability shale natural gas reserves. Impacts on major revenue sources for the state and local governments are discussed, as are expected changes in state and local government expenditures that could occur as a result of the use of the high-volume hydraulic-fracturing technique.

Given the uncertainty associated with the actual level of future development of these reserves, the rate of extraction that would occur, and the actual geographic location where development would take place, it is impossible to definitively quantify the fiscal impacts of this action.

However, some estimates have been made. These estimates should be viewed only as order-of-magnitude estimates and not as actual revenue or cost projections.

6.8.4.1 New York State

The proposed high-volume hydraulic fracturing operations would have a significant positive impact on revenues collected by New York State. Revenues in the state would increase directly as a result of lease payments for natural gas development that would occur under state-owned land and indirectly from an increase in tax revenues generated by the natural gas development and the resulting increase in economic activity throughout the state. No surface access would be granted for high-volume hydraulic fracturing operations on most state-owned lands. However, the subsurface natural gas deposits under state-owned lands could be accessed by surface operations located on privately owned lands. If the subsurface natural gas deposits under state-owned lands were extracted, New York State would receive lease payments and royalties for the mineral rights.

Currently, New York State receives lease payments for any existing or planned natural gas development on state-owned lands that are leased. These payments would also be received for any new subsurface mineral rights that are leased and/or any new wells drilled in the low-permeability shale that would access subsurface natural gas reserves under state-owned lands.

Delay rentals (i.e., rental payments that are provided to the owner of the mineral rights before drilling and production occurs) and bonus bid payments would accrue to the state when developers first purchase the right to exploit the subsurface minerals under state-owned lands. Royalty payments of 12.5% or more of gross revenues would also be provided to the state for any natural gas reserves extracted from under state-owned lands.

At this point in the planning processes it is impossible to accurately assess the exact location where these wells would be drilled and whether or not these wells would be located on private lands that could access underground reserves under state-owned lands. Therefore, it is impossible to estimate the total royalty and lease payments that would accrue to the state. However, these payments are not expected to be large relative to the total New York State budget. Currently, New York State receives approximately \$746,000 in lease payments per year for all oil and natural gas developments on state-owned lands.

The state would indirectly receive a significant increase in its revenue streams as a result of the proposed drilling in low-permeability shale. As described in Section 6.8.1 (Economy, Employment, and Income), high-volume hydraulic fracturing operations would increase employment and income throughout the state. Up to \$621.9 million to \$2.5 billion in employee earnings would be directly and indirectly generated per year at maximum build-out, depending on the development scenario.

As a result, New York State would experience a large increase in its personal income tax receipts. In 2008 the effective personal income tax rate for all taxpayers in New York State was 5.0%. If this tax rate were used for estimation purposes, at maximum build-out the state could receive between \$31 million and \$125 million a year in personal income tax receipts, depending on the level of development assumed.

In addition to the personal income tax, the state would also experience some increase in its corporate tax receipts. Corporate income in the state would increase both directly, as the natural gas developers profit from the extraction of the gas in the low-permeability shale, and indirectly due to the resulting increase in economic activity in the state. However, given the many benefits in the New York State tax code for energy companies, such as expensing, depletion and

depreciation deductions, the taxable income from the natural gas industry would be greatly reduced. In addition, 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. Also the sale of the natural gas generated by these companies may not take place in New York and, therefore, may not be subject to New York State corporate tax (NYS DTF 2011a).

Other tax receipts would also increase. Revenues generated from sales and use tax would also register an increase as industry purchased the materials needed to develop these natural gas reserves that are not exempt from state and local sales tax. However, many of the materials needed to construct these wells would be tax-exempt, including such things as piping, drill rigs, service rigs, vehicles, tools and supplies, pollution control equipment, and services to real property (NYS DTF 2011a).

The direct, indirect, and induced economic activity associated with the high-volume hydraulic fracturing would further expand sales tax receipts as the new workers spend a portion of the increased earnings in the state.

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 possible 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.

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 best available management plans were followed, and

to enforce 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 New York State's government.

6.8.4.2 Representative Regions

Development of the natural gas reserves would have a significant fiscal impact on local governments wherever drilling would take place. These impacts would be both positive and negative in nature. As described above, local government entities who take part in sales tax revenue sharing schemes would experience a substantial increase in sales tax receipts as a result of the additional economic activity that would occur within their jurisdictions. Local government entities that receive proceeds from ad valorem property taxes would see significant increases to their tax rolls and property tax receipts.

As described previously in Section 2.4.11.4, Government Revenues and Expenditures, producing natural gas wells are taxable for ad valorem real property tax purposes in New York State. Therefore, every new natural gas well operating in a local government's jurisdiction would increase that government's tax base and the total assessed value of property.

In New York State, producing natural gas wells are taxed based on the value of their production for ad valorem property tax purposes. Each year the New York State Office of Real Property Tax Service determines the "unit of production value" for a region. This unit value is then multiplied by the total amount of natural gas produced, and the state equalization rate is then applied to determine the total assessed value of the natural gas well. Applicable property tax rates are then applied to this assessed value to determine the ad valorem property tax levy. See Section 2.4.11.4, Government Revenues and Expenditures, for more details.

Using the above-mentioned formula, an estimate of local property tax revenues can be generated and extrapolated for each development scenario. Using industry estimates for the productivity of horizontal and vertical high-volume hydraulic fracturing wells, the following property tax analysis has been completed for Year 30, the year of maximum impact. See the Economic

Assessment Report for a more detailed discussion of the methodology used to estimate property tax impacts and to see data for other years.

In order to predict the change in property tax revenues that would result from the proposed development of the low-permeability shale natural gas reserves, annual production of the wells was forecasted. Many factors affect the annual production of a natural gas well. Typically, production initially starts out at a maximum level and then declines quickly until it reaches a slower rate of decline. Production then continues at this lower level for approximately 30 years. Horizontal high-volume hydraulic-fracturing wells produce more natural gas than vertical high-volume hydraulic-fracturing wells. This discrepancy has been accounted for in the analysis. For a more detailed description of projected production levels, see the Economic Assessment Report.

For the purposes of this analysis, the 2010 unit of production value for the Medina formation was used to estimate the real property tax payments of a representative horizontal high-volume hydraulic fracturing well in Broome County. When the Marcellus Shale and Utica Shale reserves are developed in New York State, specific unit of production values would be developed for that specific formation and the specific drilling techniques used in that formation. Depending on the results of that analysis, the unit of production value could vary substantially from the Medina values utilized in this report. Table 6.50 shows the estimated annual real property tax payments for a typical high-volume hydraulic-fracturing horizontal well in Broome County in each year of its operational life using the Medina formation unit of production value. See the Economic Assessment Report for additional examples.

Table 6.50 - Example of the Real Property Tax Payments From a Typical Horizontal Well (New August 2011)

			County:	Broome
			2010 Final Gas Unit of Production Value	\$11.19
			2010 Overall Full-Value Tax Rate ¹	35.5
Production Year	Annual Production (millions of cubic feet)	Assessed Value of Production ²	Property Tax Payment ³	
1	803.00	\$8,985,570	\$318,988	
2	354.05	\$3,961,820	\$140,645	
3	258.00	\$2,887,020	\$102,489	
4	201.43	\$2,253,946	\$80,015	
5	165.93	\$1,856,701	\$65,913	
6	144.50	\$1,616,955	\$57,402	
7	130.00	\$1,454,700	\$51,642	
8	119.00	\$1,331,610	\$47,272	
9	109.93	\$1,230,061	\$43,667	
10	103.20	\$1,154,850	\$40,997	
11	98.04	\$1,097,107	\$38,947	
12	93.14	\$1,042,252	\$37,000	
13	88.48	\$990,139	\$35,150	
14	84.06	\$940,633	\$33,392	
15	79.86	\$893,601	\$31,723	
16	75.86	\$848,921	\$30,137	
17	72.07	\$806,475	\$28,630	
18	68.47	\$766,151	\$27,198	
19	65.04	\$727,844	\$25,838	
20	61.79	\$691,451	\$24,547	
21	58.70	\$656,879	\$23,319	
22	55.77	\$624,035	\$22,153	
23	52.98	\$592,833	\$21,046	
24	50.33	\$563,191	\$19,993	
25	47.81	\$535,032	\$18,994	
26	45.42	\$508,280	\$18,044	
27	43.15	\$482,866	\$17,142	
28	40.99	\$458,723	\$16,285	
29	38.94	\$435,787	\$15,470	
30	37.00	\$413,997	\$14,697	
Total Property Tax Payments for the Productive Life of the Well			\$1,448,735	

Sources: NYSDTF 2011b, 2011c, 2011d, 2011e; All Consulting 2011.

Notes:

¹ Full-value tax rates are tax rates that have been already been equalized. Therefore, these numbers should not be multiplied by the state equalization rate.

² Calculated as Annual Production multiplied by 1,000 (to calculate the number of 1,000s of cubic feet) multiplied by the 2010 Final Gas Unit of Production Value (applied to each 1,000 cubic feet).

³ Calculated as Assessed Value multiplied by the Overall Full-Value Tax Rate divided by 1,000.

In estimating real property tax payments for vertical high-volume hydraulic fracturing wells it was initially assumed that each well would produce at the same average level of production as existing wells (in 2009) in the region. However, average annual production for existing wells in Region A was approximately 317.9 million cubic feet per year. This figure was deemed to be too optimistic, so a figure of 90 million cubic feet per year was used instead for Region A production. The 90 million cubic feet per year corresponds to production levels of vertical wells currently operating in the Marcellus formation in Pennsylvania (NYSDEC 2011). Region B currently has no producing natural gas wells, and its Marcellus and Utica Shale formations are similar to those found in Region A (NYSDEC 2011). Therefore, a production level of 90 million cubic feet per year was also used for Region B. In contrast, due to the geological characteristics of Region C, high-volume hydraulic fracturing vertical wells are not anticipated to have the same level of production as in Region A or Region B. High-volume, hydraulic fracturing vertical wells in Region C are anticipated to have production levels similar to other vertical wells currently operating in the region (NYSDEC 2011). Therefore, in Region C it is assumed that each well would produce at the same average level of production as existing wells (in 2009) in the region.

Table 6.51 shows the estimated annual real property tax payment from a typical vertical well. The example uses the overall full-value tax rate, which averages the property tax levies in Broome County from all taxing jurisdictions, including county, town, village, school district, and other taxing districts, and the 2010 Medina formation unit of production value. As described previously, once Marcellus Shale or Utica Shale formations become developed in New York State, specific unit of production values would be developed for that specific formation and the specific drilling techniques used in that formation. Depending on the results of that analysis, the unit of production value could vary substantially from the Medina values utilized in this report.

Table 6.51 - Example of the Real Property Tax Payments from a Typical Vertical Well (New August 2011)

County:	Broome
2010 Final Gas Unit of Production Value	\$11.19
2010 Overall Full-Value Tax Rate	35.5
Annual Production (millions of cubic feet)	90
Assessed Value of Production of Well¹	\$1,007,100
Annual Property Tax Payment²	\$35,752

Source: NYSDTF 2011b, 2011c, 2011d, 2011e; NYSDEC 1994-2006, 2007b, 2008, 2009.

Notes:

¹ Calculated as Annual Production multiplied by 1,000 (to calculate the number of 1,000s of cubic feet) multiplied by the Final Gas Unit of Production Value (applied to each 1,000 cubic feet).

² Calculated as Assessed Value of Production of Well multiplied by the Overall Full-Value Tax Rate divided by 1,000.

As shown on Table 6.52, the projected change in total assessed value and property tax receipts that would result under any of the development scenarios would be significant. Annual property tax receipts at the peak production year (Year 30) would range from \$9.1 million in Chautauqua County to \$77.5 million in Broome County under the low development scenario. For Year 30, annual property tax receipts under the average development scenario would range from \$35.4 million in Chautauqua County to \$309.3 million in Broome County, and annual property tax receipts under the high development scenario would range from \$53.1 million in Chautauqua County to \$460.0 million in Broome County (see Table 6.52).

Table 6.52 - Projected Change in Total Assessed Value and Property Tax Receipts¹ at Peak Production (Year 30), by Region (New August 2011)

	Low Development Scenario		Average Development Scenario	
	Change in Assessed Value (\$ million)	Total Property Tax Receipts (\$ million)	Change in Assessed Value (\$ million)	Total Property Tax Receipts (\$ million)
Region A				
Broome County	\$3,345	\$119	\$13,342	\$474
Chemung County	\$1,930	\$66	\$7,700	\$264
Tioga County	\$2,458	\$76	\$9,803	\$302
Total Region A	\$7,732	\$261	\$30,845	\$1,040
Region B				
Delaware County	\$1,498	\$32	\$5,996	\$127
Otsego County	\$1,040	\$20	\$4,164	\$82
Sullivan County	\$1,006	\$26	\$4,024	\$105
Total Region B	\$3,544	\$78	\$14,184	\$314
Region C				

	Low Development Scenario		Average Development Scenario	
	Change in Assessed Value (\$ million)	Total Property Tax Receipts (\$ million)	Change in Assessed Value (\$ million)	Total Property Tax Receipts (\$ million)
Cattaraugus County	\$406	\$14	\$1,583	\$56
Chautauqua County	\$329	\$11	\$1,283	\$41
Total Region C	\$735	\$25	\$2,866	\$97
Total Regions A, B, and C	\$42,856	\$364	\$47,895	\$1,451

Source: NYSDTF 2011b, 2011c, 2011d, 2011e.

¹ Property tax receipts are calculated using the overall full-value tax rate for each county. Therefore, the property tax receipts figure estimates property taxes collected from all levels of government, including county, town, village, school district, and other special taxing districts.

Note: Totals may not sum due to rounding.

The increase in ad valorem property taxes would have a significant positive impact on the finances of local government entities. While these figures are not directly comparable to the current county revenues and expenditures data presented in Section 2.4.11.4, Fiscal Conditions, the figures can be used to show the order of magnitude of these impacts. The total property tax receipts shown above were calculated using the overall full-value tax rate, meaning the impact figures presented above include town, village, school district, and other special taxing districts revenue as well county property tax receipts.

In addition to the positive fiscal impacts discussed above, local governments would also experience some significant negative fiscal impacts resulting from 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 also be required. Finally, if substantial in-migration occurs in the region as a result of drilling and production, local governments would be required to increase expenditures on other services, such as education, health and welfare, recreation, housing, and solid waste management to serve the additional population.

6.8.5 Environmental Justice

As described in previous sections, there is potential for some localized negative impacts to occur as a result of allowing high-volume hydraulic fracturing. Therefore, implementation of such projects could have localized negative impacts on environmental justice populations if the projects are sited in identified environmental justice areas. However, specific project site locations have not been selected at this time.

Currently, natural gas well permit applications are exempt from requirements in NYSDEC Commissioner Policy 29, Environmental Justice and Permitting (CP-29); therefore, additional environmental justice screening would not be required for individual well permit applications. However, some of the auxiliary permits/approvals that would be needed prior to well construction may require environmental justice screening.

When necessary, project applicants would determine whether the proposed project area is urban or rural and would perform a geographic information system (GIS)-based analysis at the census tract or block group level to identify potential environmental justice areas. If a potential environmental justice area is identified by the preliminary screening, additional community outreach activities would be required.

6.9 Visual Impacts¹³⁵

The visual impacts associated with vertical drilling in the Marcellus and Utica Shales would be similar to those discussed in the 1992 GEIS (NYSDEC 1992). Horizontal drilling and high-volume hydraulic fracturing are, in general, similar to those discussed in the 1992 GEIS (NYSDEC 1992), although changes that have occurred in the industry over the last 19 years may affect visual impacts. These visual impacts would typically result from the introduction of new landscape features into the existing settings surrounding well pad locations that are inconsistent with (i.e., different from) existing landscape features in material, form, and function. The introduction of these new landscape features would result in changes to visual resources or visually sensitive areas and would be perceived as negative or detrimental by regulating agencies and/or the viewing public.

¹³⁵ Section 6.9, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

The visual impacts of horizontal drilling and high-volume hydraulic fracturing would result from four general on-site processes associated with the development of viable well locations: construction, well development (drilling and fracturing), operation or production, and post-production reclamation. The greatest visual impacts would be associated with the construction of well pads and associated facilities, which would create new long-term features within surrounding landscapes, and well drilling and completion activities at viable well locations, which would be temporary and short-term in nature. Additional off-site activities could also result in visual impacts, including the presence of increased workforce personnel and vehicular traffic, and the use of existing or development of new off-site staging areas or contractor/storage yards.

The visual impacts of horizontal drilling and hydraulic fracturing would vary depending on topographic conditions, vegetation characteristics, the time of year, the time of day, and the distance of one or more well sites from visual resources, visually sensitive areas, or other visual receptors.

6.9.1 Changes since Publication of the 1992 GEIS that Affect the Assessment of Visual Impacts

A number of changes to equipment and drilling procedures since the 1992 GEIS have the potential to result in visual impacts over a larger surrounding area and/or visual impacts over a longer period of time. These changes can generally be separated into three categories: changes in equipment and drilling techniques; changes in the size of well pads; and changes in the nature and duration of drilling and hydraulic-fracturing activities.

6.9.1.1 Equipment and Drilling Techniques

The 1992 GEIS stated that drill rigs ranged in height from 30 feet for a small cable tool rig to 100 feet or greater for a large rotary rig. By comparison, the rigs currently used by the industry for horizontal drilling can be 140 feet or greater in height and have more supporting equipment. While a substantial amount of on-site equipment, including stationary tanks, compressors, and trucks, would be periodically present at each site during specific times of well development (drilling and fracturing), the amount of necessary on-site equipment during these times is similar to that addressed in the 1992 GEIS.

6.9.1.2 Changes in Well Pad Size and the Number of Water Storage Sites

The typical area that would undergo site clearing for an individual well pad has increased since 1992, from approximately 2 acres per site to an average of approximately 3.5 acres per site. The pad size was increased to accommodate the necessary on-site equipment for drilling and hydraulic-fracturing activities and to accommodate drill sites with multiple well pads. Since multiple wells can be drilled from the same pad, this change has resulted in fewer, but larger pads.

In addition, separate large areas for water storage are often developed in the vicinity of well pad sites. These areas look somewhat similar to well pads because of their overall size and because of the presence of specific types of equipment (primarily tanks and trucks). However, they may contain specific landscape features associated with water procurement or storage features, including large graveled areas for truck traffic, water impoundment areas, and water storage tanks that are positioned on-site as needed.

6.9.1.3 Duration and Nature of Drilling and Hydraulic-Fracturing Activities

Since 1992 there have been a number of changes in the duration of drilling and hydraulic fracturing. In the 1992 GEIS, drilling time was described as an approximately one- to two-week or longer period, and there was no mention of the time required for hydraulic fracturing (NTC 2011). Currently, to complete a horizontal well takes 4 to 5 weeks of drilling, including hydraulic fracturing.

Since 1992 the industry has been trending, where possible, toward the development of multi-well pads rather than single-well pads. Multi-well pads are slightly larger, but the equipment used is often the same. Based on current industry practice, a taller rig (170 feet in total height) with a larger footprint and substructure may be used to drill multiple wells from a single pad. In some instances, smaller rigs may be used to drill the initial hole and conductor casing to just above the kick-off point, the depth at which a vertical borehole begins to turn into a horizontal borehole. The larger rig is then used for the final horizontal portion of the hole. Typically, one or two wells are drilled and the rig is then removed.

If the well(s) are productive, the rig is brought back and the remaining wells are drilled and stimulated by the injection of hydraulic fracturing additives. There is the possibility that all wells on a pad would be drilled, stimulated, and completed consecutively, reducing the duration of visual impacts that would occur during drilling and hydraulic-fracturing activities. However, state law requires that all wells on a multi-well pad be drilled within three years of starting the first well (NTC 2011).

6.9.2 New Landscape Features Associated with the Different Phases of Horizontal Drilling and Hydraulic Fracturing

This section discusses the various visual impacts that may be associated with on-site horizontal drilling and high-volume hydraulic fracturing activities during the construction, development (drilling and fracturing), production, and reclamation phases. Visual impacts would occur in the vicinity of the different sites associated with horizontal drilling and hydraulic fracturing, such as at well pads, water impoundment and extraction sites, and the large equipment that may be present on these sites (e.g., drilling rigs), as well as at the locations of off-site areas such as contractor/equipment storage yards and staging areas, pipeline and compressor station locations, gravel pits, and disposal areas (Rumbach 2011). Additional off-site activities that may result in impacts on visual resources or visually sensitive areas during one or more of these phases are discussed in Section 6.9.3.

6.9.2.1 New Landscape Features Associated with the Construction of Well Pads

New landscape features that would be associated with the construction of well sites include open, level areas averaging approximately 3.5 acres in size that would serve as the well pad; construction equipment, including bulldozers, graders, backhoes, and other large equipment to construct level areas using clearing, cutting, filling and grading techniques; trucks for hauling equipment and materials; and worker vehicles. Newly created sites would appear as open, level areas with newly exposed earthen areas, albeit mulched or otherwise protected for erosion control, similar to the appearance of the construction activities for a water impoundment area as shown in Figure 5.22 in Section 5.7.2.

Photo 6.1 below shows a well site where wells have already been drilled and completion operations are underway. The photograph shows evidence of grading, cutting, and filling

activities; the use of gravel for site preparation; and mulching along an earthen embankment to prevent erosion—all activities implemented during construction activities. A portion of a newly created linear right-of-way for a connecting pipeline is shown on the hillside in the background of the photo. The red and blue tanks shown in Photo 6.1 are discussed in greater detail in Section 6.9.2.2.

Photo 6.1 - A representative view of completion activities at a recently constructed well pad (New August 2011)



Photo 6.2 below shows the same recently constructed well pad that is currently under development, but from a different angle. In the foreground of the photograph below, the newly created access road leading to the well pad is shown. Erosion control measures and materials are also shown in the photograph, including channeling, gravel fill and hay bales in the channel, and mulching on topsoil or spoil piles to the left of the access road to minimize erosion. Additional views of access roads are presented in Photos 5.1 through 5.4 in Section 5.1.1 and in Photo 6.2. Tanks, vehicles, and other equipment are discussed in greater detail in Section 6.9.2.2.

Photo 6_2 - A representative view of completion activities at a recently constructed well pad, showing a newly created access road in foreground (New August 2011)



If water impoundment sites are necessary, they would be located in the same general area as well sites, approximately the same size as a well site, and also be generally level. However, they would also contain one or more large earthen embankments encircling plastic-lined ponds. See Photo 6_3 below. Photos 5.20 and 5.22 in Section 5.7.2 contain additional representative views of water impoundment sites.

Photo 6.3 - A representative view of a newly constructed water impoundment area (New August 2011)



If water procurement sites are necessary, such sites would be located near water withdrawal locations (typically rivers or other large sources of water) and would consist of large, newly created graveled areas sufficiently sized for tanker truck use and equipped with on-site water pumps and metering equipment, as shown in Photo 6.4. Photos 5.19a and 5.19b in Section 5.7.2 contain additional representative views of water procurement sites.

Photo 6.4 - A representative view of a water procurement site (New August 2011)



Additional areas associated with the construction of well sites would include newly created access roads and pipeline rights-of-way for connector pipelines (see Photo 6.1 and Photo 6.2). These sites would typically be narrow, linear features, as opposed to the large open areas needed for well pads and water impoundment or procurement sites.

6.9.2.2 New Landscape Features Associated with Drilling Activities at Well Pads

New landscape features that would be associated with drilling activities include drill rigs of various heights and dimensions, including the rotary rigs as described in the 1992 GEIS, with heights ranging from 40 to 45 feet for single rigs and 70 to 80 feet for double rigs. Currently, the industry also uses triple rigs that can be more than 100 feet in height. As discussed in Section 5.2.1, only the rig used to drill the horizontal portion of the well is likely to be significantly larger than what is described in the 1992 GEIS. This rig may be a triple, with a substructure height of about 20 feet, a mast height of about 150 feet, and a surface footprint of about 14,000 square feet, which would include auxiliary equipment. Auxiliary equipment would include on-site tanks for holding water, fuel, and drilling mud; generators; compressors; solids control equipment (shale shaker, de-silter, desander); a choke manifold; an accumulator; pipe racks; and the crew's office space.

Photos 6.16, 6.17 and 6.20 show what a typical well pad may look like during the drilling of wells at a well pad. These photos show the industrial appearance of the well pad during the drilling phase, which would appear dramatically different from the pad's surrounding setting for the approximately 4- to 5-week duration of drilling activities.

6.9.2.3 New Landscape Features Associated with Hydraulic Fracturing Activities at Well Pads

New landscape features that would be associated with fracturing activities include an extensive array of equipment, which would cover almost the entire well pad. Photo 6.5 shows what a typical well site may look like during the hydraulic fracturing of wells at a well pad. This view is upslope of a well site that is under development. The photo shows the industrial appearance of the well site during the hydraulic fracturing phase, which would appear dramatically different from the site's surrounding setting for the 3- to 5-day duration of hydraulic fracturing activities. This view includes a water impoundment site (visible in the right background of the photo) and a

portion of new right-of-way for a connector pipeline (visible on another hillside in the left background of the photo).

Photo 6.5 - A representative view of active high-volume hydraulic fracturing (New August 2011)



The equipment typically present during hydraulic fracturing includes the following:

- storage tanks that contain the water and additives used for hydraulic fracturing (rectangular red tanks on well site shown in Photo 6.5);
- tanks containing chemicals used in the fracturing process or for storage of liquefied natural gas produced during hydraulic fracturing (blue rectangular tanks on well site shown in Photo 6.5);
- compressors (large cylindrical blue equipment and smaller dark green equipment with stacks or vents shown in Photo 6.5) used for pumping product through various hoses and pipelines;
- miscellaneous trucks, including tractor trailers and other large trucks for hauling sand and hydraulic fracturing additives, pipe-hauling trucks, welding and other mechanical support trucks, and a crane; and
- miscellaneous worker vehicles (almost all of the white or silver vehicles shown in Photo 6.5).

6.9.2.4 New Landscape Features Associated with Production at Viable Well Sites

New landscape features associated with production at productive well sites would be relatively minimal. Following the establishment of viable wells, all of the fracturing equipment and vehicles shown in Photo 6.5 above would be removed from the site, and the site would be landscaped with either gravel or low-lying grassy vegetation. Some aboveground structures would be installed and remain on-site for the duration of production, including one or more wellheads, small storage tanks, and a metering system for the pipeline connections; however, these new aboveground structures would be small, less prominent landscape features, which over time would become part of the existing setting of the well site and its surrounding area. Photos 6.12, 6.13, 6.17, and 6.20 at the end of Chapter 6 show the appearance of well sites during the production phase and the appearance of the same well sites during the earlier fracturing phase.

6.9.2.5 New Landscape Features Associated with the Reclamation of Well Sites

If well sites are restored to their original topographic configuration and vegetative cover, on-site aboveground structures associated with well production are removed and new landscape features are introduced. The new landscape features would temporarily include bare areas, which would be created by the large-scale earthmoving activity necessary to re-create the pre-existing terrain conditions, and newly placed erosion control materials and vegetation to prevent erosion and facilitate the successful reestablishment of vegetation covers, which would, over time, revert to pre-existing vegetation patterns and species.

6.9.3 Visual Impacts Associated with the Different Phases of Horizontal Drilling and Hydraulic Fracturing

Impacts on visual resources or visually sensitive areas such as those identified in Section 2.4 would result at or in the vicinity of individual well locations. The following five general categories of visual impacts result from horizontal drilling and high-volume hydraulic-fracturing activities:

- construction-related impacts associated with the preparation of drill sites, including the construction of access roads, connecting pipelines, and other ancillary facilities; work during this phase progresses in a linear fashion, with impacts at any one location occurring for up to several weeks;

- development-related impacts associated with the drilling of wells, including the presence of drill rigs and equipment during the drilling phase; work during this phase progresses over an approximately 2- to 3-week period;
- development-related impacts associated with the fracturing of wells, including the presence of storage tanks, compressors, trucks, and other equipment that supports fracturing activities; work during this phase progresses over an approximately 2- to 3-week period;
- operational impacts associated with active well sites, which include the presence of production equipment if the well site is viable; this low-impact phase involves small pieces of equipment and pipeline connections for up to 30 years; and
- reclamation impacts associated with the removal of production equipment and the restoration of well site locations when operations are complete.

6.9.3.1 Visual Impacts Associated with Construction of Well Pads

Construction-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.4 would result from clearing and site preparation activities associated with access roads, well pads, connecting gas pipelines, retaining structures, and other support facilities such as water impoundments and water procurement sites. They would also include the impacts of site-specific construction-related traffic on both new and existing road systems. The end product of construction-related activities would be the creation of well sites and support facilities that are new landscape features within the surrounding existing setting, which may be incompatible with existing visual settings and land uses.

These construction-related visual impacts may be direct (i.e., impact the existing visual setting of a well location) or indirect (i.e., impact the existing visual setting of areas in the vicinity of a well location, including views that contain a well location). These visual impacts would be temporary or of short-term duration (i.e., a matter of months while construction is underway), and may generally be perceived as negative throughout their duration. These impacts on visual resources or visually sensitive areas would be both site-specific (i.e., within views that contain individual well locations) and cumulative (i.e., within views of areas or regions that contain concentrations of well locations).

6.9.3.2 Visual Impacts Associated with Drilling Activities on Well Pads

Development-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.4 would result from the introduction of new and visible landscape features and activities into the existing settings that surround well locations. During drilling activities, such landscape features would include the newly created well pad sites, including associated access roads, pipeline rights-of-way, and other aboveground site facilities or structures such as water impoundment areas; the tall drill rigs; and on-site equipment to support drilling activities, such as on-site tanks for holding water, fuel, and drilling mud; generators; compressors; solids control equipment; a choke manifold; an accumulator; pipe racks; and the crew's office space.

Drilling rigs, which can reach heights of 150 feet or more, would be the most visible sign of drilling activity and when viewed from relatively short distances, such as from 1,000 feet to 0.5 miles, are relatively prominent landscape features. Because drilling may operate 24 hours a day, additional nighttime visual impacts may occur from rig lighting and open flaring (Rumbach 2011, Upadhyay and Bu 2010). Additional new and visible landscape features would include traffic related to the drilling of wells, including worker vehicles and heavy equipment used to drill wells at each well site.

Drilling-related visual impacts may be direct (i.e., impact the existing visual setting of a well location) or indirect (i.e., impact the existing visual settings of areas surrounding a well location, including views that include a well location). These visual impacts would be temporary or of short-term duration (i.e., a matter of weeks while drilling is underway), and would generally be perceived as negative throughout their duration, primarily because of the high visibility of drilling activities from surrounding vantage points. While drilling activities are generally considered temporary or of short-duration, they may occur a number of times at well locations over a three-year period following the date that the initial drilling on a well site commences. These impacts on visual resources or visually sensitive areas would be both site-specific (i.e., within views that contain individual well locations) and cumulative (i.e., within views of areas or regions that contain concentrations of well locations).

6.9.3.3 Visual Impacts Associated with Hydraulic Fracturing Activities at Well Sites

Fracturing-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.4 would result from the introduction of new and visible landscape features and activities into the existing settings that surround well locations. During fracturing activities, such landscape features would include the newly created well pad sites, including: associated access roads, pipeline rights-of-way, and other aboveground site facilities or structures such as water impoundment areas; on-site equipment such storage vessels, trucks, and other equipment within containment areas; and buildings or other aboveground structures. 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. Additional new and visible landscape features would include traffic related to the development of wells, including worker vehicles and heavy equipment used at each well site.

Fracturing-related visual impacts may be direct (i.e., impact the existing visual setting of a well location) or indirect (i.e., impact the existing visual settings of areas surrounding a well location, including views that include a well location). These visual impacts would be temporary or of short-term duration (i.e., a matter of weeks while hydraulic fracturing is underway) and would generally be perceived as negative throughout their duration, primarily because of the high visibility of fracturing activities from surrounding vantage points. While fracturing activities are generally considered temporary and of short duration, they would occur a number of times during the three-year period during which all wells at a well location would have to be drilled and fractured, and then episodically at well locations over the lifetime of the well, if hydraulic fracturing activities are repeated at wells to keep them viable (in production). These impacts on visual resources or visually sensitive areas would be both site-specific (i.e., within views that contain individual well locations) and cumulative (i.e., within views of areas or regions that contain concentrations of well locations).

6.9.3.4 Visual Impacts Associated with Production at Well Sites

Operations-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.4 would result from extraction activities at viable well sites. The visual impacts of production would be less intrusive in surrounding landscapes, primarily because minimal on-site equipment is necessary during productions. Well site locations would consist of large, level

grassy or graveled areas, with wellhead locations and small aboveground facilities for extraction and transfer of product into gas lines. Thousands of similar wellhead installations are already present in the area underlain by the Marcellus and Utica Shales in New York and may be considered relatively unobtrusive landscape features (see Photos 6.11 through 6.20 at the end of Chapter 6). Although there would be some traffic associated with operations, including worker vehicles and equipment needed for operation and maintenance activities, the presence of such traffic would be substantially less than the traffic generated during construction and development (drilling and fracturing) of the wells.

Production-related visual impacts would be direct (i.e., directly impact the existing visual setting of a well location) and indirect (i.e., indirectly impact the existing settings within viewsheds that would contain a well location, including views of and from visual resources or visually sensitive areas that would also contain a well location) and would be of long-term duration (i.e., a number of years while active well sites remain viable). Operations-related visual impacts may initially be considered as having the potential for high visibility from surrounding vantage points, particularly when well locations are developed. However, over the lifetime of wells at a well location, which could be as long as 30 years from the commencement of drilling, operation-related activities at viable well pad locations would become integral features within their surrounding landscapes. These impacts on visual resources or visually sensitive areas would be both site-specific (i.e., within views that contain individual well locations) and cumulative (i.e., within views of areas or regions that contain concentrations of well locations).

6.9.3.5 Visual Impacts Associated with the Reclamation of Well Sites

Reclamation-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.4 would result from the removal of on-site well equipment and structures and from site restoration activities. Site restoration activities would include recontouring the terrain at well sites to reestablish pre-existing topographic conditions and planting appropriate vegetative cover to reestablish appropriate site-specific vegetation species and growth patterns. Subsequent periodic reclamation-related visual impacts may also result from post-restoration inspection or monitoring and measures needed to ensure the successful reestablishment and succession of vegetation.

Reclamation-related visual impacts would be direct (i.e., directly impact the existing visual setting of a well location) and indirect (i.e., indirectly impact the existing settings within viewsheds that would contain a well location, including views of and from visual resources or visually sensitive areas that would also contain a well location). The duration of these temporary impacts would range from short term to long term. For example, removing well equipment and structures, recontouring the terrain, and replanting appropriate vegetation to reestablish pre-existing conditions would be of short-term duration (a matter of weeks or months). However, reclamation of forested areas may be of long-term duration.

Additional post-reclamation restoration activities may be necessary to ensure successful reestablishment of vegetation, consisting of periodic inspection or monitoring and implementation of any corrective actions to facilitate successful revegetation (such as corrective erosion control measures or vegetative replanting efforts). These activities would be episodic and may range from short-term to long term duration (from several months to as long as 1 to 3 years) to ensure successful revegetation. The potential impacts of short- to long-term inspection and monitoring activities on visual resources or visually sensitive areas during restoration are expected to be episodic and generally range from neutral to beneficial as vegetation succession proceeds.

All of the reclamation-related impacts on visual resources or visually sensitive areas would be both site specific (e.g., within views that contain individual well locations) and cumulative (e.g., within views of areas or regions containing concentrations of well locations).

6.9.4 Visual Impacts of Off-site Activities Associated with Horizontal Drilling and Hydraulic Fracturing

Section 6.9.3 discusses the nature of impacts on visual resources or visually sensitive areas that may be associated with on-site horizontal drilling and hydraulic-fracturing activities. However, off-site activities that could occur during one or more of the construction, development (drilling and fracturing), production, and reclamation phases also may result in additional indirect impacts on visual resources or visually sensitive areas, particularly during the periodic influx of specialized workforces during various phases of development. Such off-site activities may include changes in traffic volumes and patterns, depending on the phase of development

occurring at one or more well sites in an area; and the development and/or use of existing or new contractor yards or equipment storage areas or other staging areas that may be necessary at various times (Upadhyay and Bu 2010).

The periodic and temporary influx of specialized workforces at various phases of development may also result in increased use of recreational vehicle or other camping areas (areas with cabins or designated for tent camping) for temporary or seasonal housing. While such camping areas may experience a congested appearance during such an influx, these areas are specifically designed for recreational vehicle or other camping activities, and the use of such areas in accordance with facility-specific occupancy rates may not be considered a negative impact on visual resources or visually sensitive areas.

The appearance and movement of specialized and large equipment and vehicles would result in temporary increases in traffic volumes and changes to traffic patterns, which would occur at various times during the construction, development (drilling and fracturing), and reclamation phases. This additional specialized traffic would occur on existing interstates, highways, and secondary roads and could result in increased congestion at intersections and bottlenecks (e.g., curves or bridges) or during particular hours (such as in the mornings and afternoons during the school year). This traffic would generally result in the increased visibility of construction- or production-related vehicles in the surrounding landscape. The new or increased presence of such specialized traffic may be considered a negative impact, particularly on highways and secondary roads that typically do not experience such construction-related traffic.

Additional cumulative visual impacts from traffic during the construction and development (drilling and fracturing) phase may occur where a number of wells are developed near each other at the same time, resulting in increased amounts of traffic. For areas with multiple well sites, this potential increase in traffic during the construction and development (drilling and fracturing) phase could increase the extent and duration of cumulative visual impacts. This potential cumulative visual impact from traffic used to construct and develop multiple well sites in an area might be reduced if the same operator develops multiple pads, because the same equipment may be used in phases to reduce the overall need and cost for the movement of equipment and materials.

The development of new and/or use of existing contractor yards or equipment storage areas or other staging areas may be necessary at various times during the construction, development (drilling and fracturing), and reclamation phases. Such areas may have a congested appearance during their use. If existing, previously developed contractor/storage yards or staging areas are used for such activities, their temporary and periodic use would be consistent with their existing setting and would have no new impact on visual resources or visually sensitive areas. However, if new yards or staging areas have to be created, the temporary and periodic use of such areas may represent a new impact on visual resources or visually sensitive areas.

6.9.5 Previous Evaluations of Visual Impacts from Horizontal Drilling and Hydraulic Fracturing

In 2010, students associated with the Department of City and Regional Planning at Cornell University, in Ithaca, New York, conducted a visual impact assessment of the hydraulic drilling process currently utilized in the Marcellus Shale region in Pennsylvania (specifically in Bradford County) (Upadhyay and Bu 2010). The purpose of this visual impact assessment was to describe the various activities and landscape features associated with horizontal drilling and hydraulic fracturing at individual well sites and across regions, and to examine the impacts or prominence of new landscape features at well sites in views from surrounding areas at specific distances and/or during different times of the day and year.¹³⁶

The study also included evaluations of the potential for impacts on visual resources or visually sensitive areas at three existing well sites in Bradford County, Pennsylvania, using criteria presented in the New York State Environmental Quality Review (SEQR) Visual EAF Addendum. The evaluations were conducted to determine the way visual impacts from such sites would be considered in accordance with New York State guidelines for assessing visual impacts under the SEQR process. In addition, the visual impact study included predictive modeling for the appearance of one or more new well sites within views from State Route 13

¹³⁶ The visual impact assessment considered the visual impacts of only two well sites. Visual impact analysis was conducted primarily during the day; while some photodocumentation of the appearance of well sites was included in the visual impact assessment, the distances of nighttime views of the well sites were not specified. The assessment did not conduct analyses for the well sites during all phases of development (i.e., construction, development, production, and reclamation). The assessment also did not conduct similar analyses for off-site activities that might result in visual impacts (i.e., at areas used for temporary worker housing, areas experiencing high levels of construction or production-related traffic, or at contractor/storage yards or staging areas).

near Cayuga Heights and from Cornell University's Libe Slope, which are considered locally significant visually sensitive areas by the City of Ithaca, and recommended potential mitigation measures to minimize or mitigate negative impacts on visual resources or visually sensitive areas.

In the 2010 visual impact assessment, the descriptions and photographs of the various phases of horizontal drilling and hydraulic-fracturing activities that resulted in new landscape features in Bradford County, Pennsylvania, are generally consistent with the descriptions and photographs of the same processes presented in Section 6.9.2 and appear to correspond to the same phases of well development (construction, well development (drilling and fracturing), production, and reclamation) that are discussed above in Section 6.9.3.

Upadhyay and Bu's evaluation of existing visual impacts consisted of examining the daytime visibility of two different well locations in Bradford County, Pennsylvania, from various distances ranging from 1,000 feet to 3.5 miles from the sites.¹³⁷ The results of this study cannot be considered definitive because the visibility of only two well sites was examined and the examination was conducted primarily during daylight hours. However, the visibility of the two well sites appeared to be relatively limited at distances ranging from 0.5 to 3.5 miles away (Upadhyay and Bu 2010). The relatively restricted daytime visibility appears to be the result of perspective (i.e., landscape features associated with well sites do not appear as prominent features within the landscape at distances of a mile or more) and/or effective screening by sloping terrain and vegetative cover.

The 2010 visual impact assessment also included four nighttime photographs of well sites in Bradford County, Pennsylvania. Lighting for nighttime on-site operations or production

¹³⁷ Regions within the area underlain by the Marcellus and Utica Shales in New York have settings similar to that of Bradford County, Pennsylvania; thus, similar visual impacts from well sites may be expected. However, a number of different, if not unique, geographic conditions or settings are present in the Marcellus and Utica Shale area in New York, including: a large number of lakes and rivers and other natural areas used for recreational purposes and possessing scenic qualities; a number of regions that are primarily rolling agricultural land rather than sloping forestland (resulting in potentially increased visibility of landscape features from greater distances); and a number of cities connected by interstate and state highways (resulting in the potential for an increase in the number of views of and from visual resources or visually sensitive areas that would contain well sites, and in the potential for an increase in size of the viewing public). These different or unique geographic conditions and settings contain associated visual resources and visually sensitive areas, including those described above in Section 2.4, that may be affected by new landscape features associated with well sites (including off-site areas and activities) and that would be noticeable to the viewing public.

activities and lighting on equipment are visible in these views; a nighttime view of flaring from at least one well site is also presented in the visual impact assessment (Upadhyay and Bu 2010). Similar documentation of the nighttime appearance of well sites during the drilling phase was also provided in the Southern Tier Central Regional Planning and Development Boards (STC) approved Marcellus Tourism Study (Rumbach 2011).

While these photographs present the potential impacts of horizontal drilling and hydraulic-fracturing activities on visual resources and visually sensitive areas at night, a number of factors should be reflected in the analysis of nighttime impacts on visual resources or visually sensitive areas. First, the nighttime impacts of lighting or flaring would be temporary and limited primarily to the well development phase of horizontal drilling and hydraulic fracturing. 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. Second, the aesthetic qualities of visual resources or visually sensitive areas are typically not accessible (i.e., visible) at night. Third, the majority of the viewing public would typically not be present at the locations of most types of visual resources or visually sensitive areas during nighttime hours, with the exception of campgrounds, lakes, rivers, or other potentially scenic areas where recreational activities may extend into evening and nighttime hours for part of the year, or with the exception of nighttime drivers, whose view of flaring would be transient. Therefore, it is likely that the temporary negative impacts of any nighttime lighting and flaring would be either visible to only a small segment of the viewing public, or visible by a larger segment of the viewing public but only on a seasonal short-term basis.

The 2010 visual impact assessment (Upadhyay and Bu 2010) also included an evaluation of three well sites in Bradford County, Pennsylvania, using the criteria listed in NYSDEC's Visual Environmental Assessment Form (NYSDEC 2011a). These three sites are in settings that are similar to areas within the area underlain by the Marcellus and Utica Shales in New York.

Two of the three well sites were in the production phase; the third site contained an active drill rig, suggesting that it was in the drilling phase. All of the sites were in rural areas where there were no visual resources or visually sensitive areas as described in Section 2.4. All of the sites

were in close proximity to other similar well sites and were visible from local nearby roadways and from a distance of 0.5 to 3 miles away. At two sites, agricultural and forest vegetation would provide seasonal screening; the third site was on or near the top of a hill and was visible from a larger surrounding area, despite the presence of forest vegetation (Upadhyay and Bu 2010).

Although no conclusions about the significance of potential visual impacts were made based on the criteria listed in NYSDEC's Visual Environmental Assessment Form (NYSDEC 2011a), it is likely that none of these well sites would be considered to have any significant visual impacts, primarily because no visual resources or visually sensitive areas as described in Section 2.4 are present, and it is likely that no further assessment or mitigation of visual impacts as described in NYSDEC Program Policy DEP-00-2 would be recommended or determined to be necessary.

Upadhyay and Bu's visual impact assessment also conducted limited three-dimensional modeling to examine the potential visual impacts of well sites during the drilling phase, when drill rigs are on-site, in two landscapes in the Ithaca area in Tompkins County, New York. Tompkins County, including the Ithaca area, is within the area underlain by the Marcellus and Utica Shales in New York. The two landscapes used for modeling consisted of (1) a view facing west of slopes on the western side of Cayuga Lake, from southbound Route 13 near Cayuga Heights (Cayuga Heights is a neighboring town along Cayuga Lake, just north of Ithaca on Route 13); and (2) a view facing west of upland well sites on the western side of Cayuga Inlet from Libe Slope on the Cornell University campus in Ithaca. The vantage points of both photos are estimated to be approximately 2.5 miles from the modeled well site locations. None of the modeled well sites appear to be prominent new landscape features within these locally designated scenic views. These results support similar conclusions made above, which were based on the daytime photographs of the existing wells in Bradford County, Pennsylvania, from various vantage points along surrounding local roads, i.e., that the visibility of new landscape features associated with well sites tends to be minimal from distances beyond 1 mile.

The potential for visual impacts from other new landscape features associated with the horizontal drilling and hydraulic fracturing process, such as interconnections with natural gas pipelines, was also considered in the STC's Marcellus Tourism Study (Rumbach 2011). This study suggested

that potential impacts from the creation of new pipeline-rights-of-way might result in changes in vegetation patterns, primarily through the creation of new and visible corridors, particularly where forest would be removed. In addition, the study considered the potential for cumulative visual impacts of multiple well sites and associated off-site facilities across a relatively large area such as the STC region (which is comprised of Steuben, Schuyler, and Chemung counties). The overall conclusion of the STC's Marcellus Tourism Study was that cumulative visual impacts of multiple well sites and their associated off-site facilities may result from the creation of an industrial landscape that is not compatible with the current scenic qualities that are recognized for the STC region (Rumbach 2011).

The evaluation of existing and potential visual impacts of multiple well sites and their associated offsite facilities by Upadhyay and Bu (2010) and Rumbach (2011) generated information and conclusions that were considered when developing the visual impacts presented in Section 6.9.3 for the different phases of well site development in the area underlain by the Marcellus and Utica Shales in New York.

6.9.6 Assessment of Visual Impacts using NYSDEC Policy and Guidance

An assessment of a project's potential for visual impacts is generally part of the SEQOR process and is triggered for Type I or unlisted projects, particularly when a Full Environmental Assessment Form (EAF) is required (NYSDEC 2011b). An addendum to the Full EAF, the Visual EAF Form, evaluates the potential for visual impacts and is required for those projects that may have an effect on aesthetic resources (NYSDEC 2011c).

The Visual EAF Form provides additional information on a project's potential visual impacts and their magnitude, including: information on the visibility of the project from visual resources and visually sensitive areas such as those described in Section 2.4; whether the visibility of the project is seasonal and whether the public uses any of the identified visual resources or visually sensitive areas during seasons when the project may be visible; a description of the surrounding visual environment; whether there are any similar projects within a 3-mile radius; the annual number of viewers likely to observe the proposed project; and the situation or activity in which the viewers are engaged while viewing the proposed project (NYSDEC 2011a).

In the event that significant resources such as those described in Section 2.4 are present and have viewsheds that contain proposed well sites, a formal visual assessment consistent with the procedures outlined in NYSDEC DEP-00-2 would be conducted. This formal visual assessment would consist of developing, “at a minimum, a line-of-sight profile, or depending upon the scope and potential significance of the activity, a digital viewshed” (such as computer-generated models or visual simulations) to determine whether a significant visual resource or visually sensitive area is within potential viewsheds of the proposed project (NYSDEC 2000).

Procedures for formal visual assessments would use control points established by NYSDEC staff and would include a worst-case scenario. A worst-case scenario for visual assessments is established using control points that reveal any project visibility at a visually significant resource. Generally, control points for the worst-case scenario are located in an attempt to reveal the tallest facility or project component. In addition, the impact area that would be evaluated in the formal visual assessment would be determined by NYSDEC staff and may be as large as a 5-mile-radius area around a project’s various components (NYSDEC 2000).

NYSDEC staff would verify the potential significance of impacts on visual resources or visually sensitive areas using the qualities of the specific resource(s) and the juxtaposition of the project’s components (using viewshed and/or line-of-sight profiles) as the guide for determining significance. If determined significant, visual impacts may require mitigation in accordance with NYSDEC DEP-000-2 guidelines (NYSDEC 2000). Procedures for mitigation are discussed in greater detail in Section 7.9.

6.9.7 Summary of Visual Impacts

The potential impacts of well development on visual resource and visually sensitive areas such as those identified in Section 2.4.12 are summarized below in Table 6.53. These potential impacts may result from on-site activities associated with construction, drilling, fracturing, production and reclamation; off-site activities associated with increased traffic; and the use of off-site areas for construction, staging, and housing. Given the generic nature of this analysis and the lack of specific well pad locations to evaluate for potential visual impacts, the impacts presented in this section are not resource-specific. Generic mitigation measures for these potential generic impacts are presented in Section 7.9.

Table 6.53 - Summary of Generic Visual Impacts Resulting from Horizontal Drilling and Hydraulic Fracturing in the Marcellus and Utica Shale Area of New York (New August 2011)

Description of Activity	Description of Typical New Landscape Features	Description of Potential Visual Impacts
On-site Well Pad Construction	<ul style="list-style-type: none"> • Newly created well pads - open, level areas averaging approximately 3.5 acres in size • Newly created linear features such as access roads and connecting pipelines • Newly created water impoundment areas (if necessary) • Construction equipment, including bulldozers, graders, backhoes, and other large equipment for clearing, cutting, filling and grading activities • Trucks for hauling equipment and materials • Worker vehicles 	<ul style="list-style-type: none"> • Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing visual setting of areas in the vicinity of a well location, including views that contain a well location • Temporary or short-term duration - during the weeks or months while construction is underway • Negative - because of the introduction of new features into the landscape • Site-specific - within views that contain individual well locations • Cumulative - within views of areas or regions that contain concentrations of well locations
On-site Well Drilling	<ul style="list-style-type: none"> • Drill rigs of varying heights and dimensions • Auxiliary on-site equipment such as storage tanks for water, fuel, and drilling mud; generators; compressors; solids control equipment; a choke manifold; an accumulator; pipe racks; and the crew's office space • Trucks for hauling equipment and materials • Worker vehicles 	<ul style="list-style-type: none"> • Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing visual settings of areas surrounding a well location, including views that include a well location • Temporary - during the weeks while drilling is underway • Periodic - during the times when drilling may occur over a three-year period following the date that the initial drilling on a well site commences • Negative - throughout the duration of drilling, primarily because of the high visibility of drilling activities from surrounding vantage points • Site-specific - within views that contain individual well locations • Cumulative - within views of areas or regions that contain concentrations of well locations

Description of Activity	Description of Typical New Landscape Features	Description of Potential Visual Impacts
On-site Well Fracturing	<ul style="list-style-type: none"> • On-site equipment such as storage tanks for water, fuel, and fracturing additives; compressors; cranes; pipe racks; and the crew's office space • Trucks, including tractor trailers and other large trucks for hauling sand and fracturing additives, pipe-hauling trucks, welding and other mechanical support trucks • Worker vehicles 	<ul style="list-style-type: none"> • Direct impacts – on the existing visual setting of a well location • Indirect impacts - on the existing visual settings of areas surrounding a well location, including views that include a well location • Temporary or short-term duration – during the weeks while hydraulic fracturing is underway • Periodic - during the times when fracturing may occur over the lifetime of the well(s) • Negative - throughout their duration, primarily because of the high visibility of fracturing activities from surrounding vantage points. • Site-specific - within views that contain individual well locations • Cumulative – within views of areas or regions that contain concentration of well locations
Well Production	<ul style="list-style-type: none"> • Operating well pads - open, level areas averaging approximately 0.5 to 1.0 acre in size, maintained in grassy or graveled conditions • Wellhead locations and small aboveground facilities for the pumping and transfer of product into gas lines. • Access road maintained in graveled condition • Connecting pipeline right-of-way maintained with grassy vegetation 	<ul style="list-style-type: none"> • Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing settings within viewsheds that contain a well location • Long-term duration - during the years while active well sites remain viable • Negative - during short-term period of initial development • Neutral - during long-term period of production over a potential 30-year period • Site specific - within views that contain individual well locations • Cumulative – within views of areas or regions that contain concentrations of well locations

Description of Activity	Description of Typical New Landscape Features	Description of Potential Visual Impacts
On-site Well Site Reclamation	<ul style="list-style-type: none"> • Initial bare areas resulting from the removal of wellheads and small aboveground facilities used during production; recontouring to pre-existing terrain conditions; and revegetation efforts • Subsequent vegetated areas reverting to pre-existing vegetation patterns and species 	<ul style="list-style-type: none"> • Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing settings within viewsheds that would contain a well location • Temporary to short term - during removal of well equipment and structures, recontouring terrain, and replanting of vegetation • Periodic and long-term - during periodic inspection or monitoring and implementation of any corrective actions to facilitate successful revegetation for several months to as long as one to three years • Neutral to beneficial - as vegetation succession proceeds • Site specific - within views that contain individual well locations • Cumulative – within views of areas or regions containing concentrations of well locations
Off-site changes in traffic volumes and patterns	<ul style="list-style-type: none"> • Increased traffic during the construction, drilling and fracturing, and reclamation phases of well development • Increased traffic would be local (at one or more well sites in close proximity) • Increased traffic may be regional (in areas where numerous multi-well sites are under development) 	<ul style="list-style-type: none"> • Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing settings within viewsheds that contain a well location • Temporary and periodic - during specific phases of well development (construction, drilling, fracturing, and reclamation) • Negative - due to the appearance and movement of high numbers of specialized and large equipment and vehicles • Site specific - at specific well locations • Cumulative – within views of areas or regions containing concentrations of well locations under development at the same time

Description of Activity	Description of Typical New Landscape Features	Description of Potential Visual Impacts
<p>Off-site periodic and temporary influx of specialized workforces at various phases of development</p>	<ul style="list-style-type: none"> • Increased use of local recreational vehicle or other camping areas (areas with cabins or designated for tent camping) for temporary or seasonal housing. • Increased local worker traffic during and after working hours 	<ul style="list-style-type: none"> • Direct impacts - on the existing visual setting of off-site housing locations and on local roads • Indirect impacts - on the existing settings within viewsheds that would contain off-site housing and local roads • Temporary and periodic - during specific phases of well development (construction, drilling, fracturing, and reclamation) • Neutral to negative - occupancy of existing off-site housing locations would be consistent with capacity, but local traffic may result in congestion during and after work hours • Site-specific – at specific housing locations and along local roads
<p>Off-site contractor yards or equipment storage areas or other staging areas</p>	<ul style="list-style-type: none"> • Increased traffic and activity associated with construction and use of new contractor yards, equipment storage areas or other staging areas • Increased traffic and activity associated with use of existing contractor yards, equipment storage areas, or other staging areas 	<ul style="list-style-type: none"> • Direct impacts - on the existing visual setting of an off-site yard, storage area, or staging area • Indirect impacts - on the existing settings within viewsheds that contain an off-site yard, storage area, or staging area • Temporary and periodic - during specific phases of well development (construction, drilling, fracturing, and reclamation) • Negative - due to the appearance and movement of high numbers of specialized and large equipment and vehicles • Site specific – at specific off-site yard, storage area, or staging area locations