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 “influent” 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 Impacts[3]

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.

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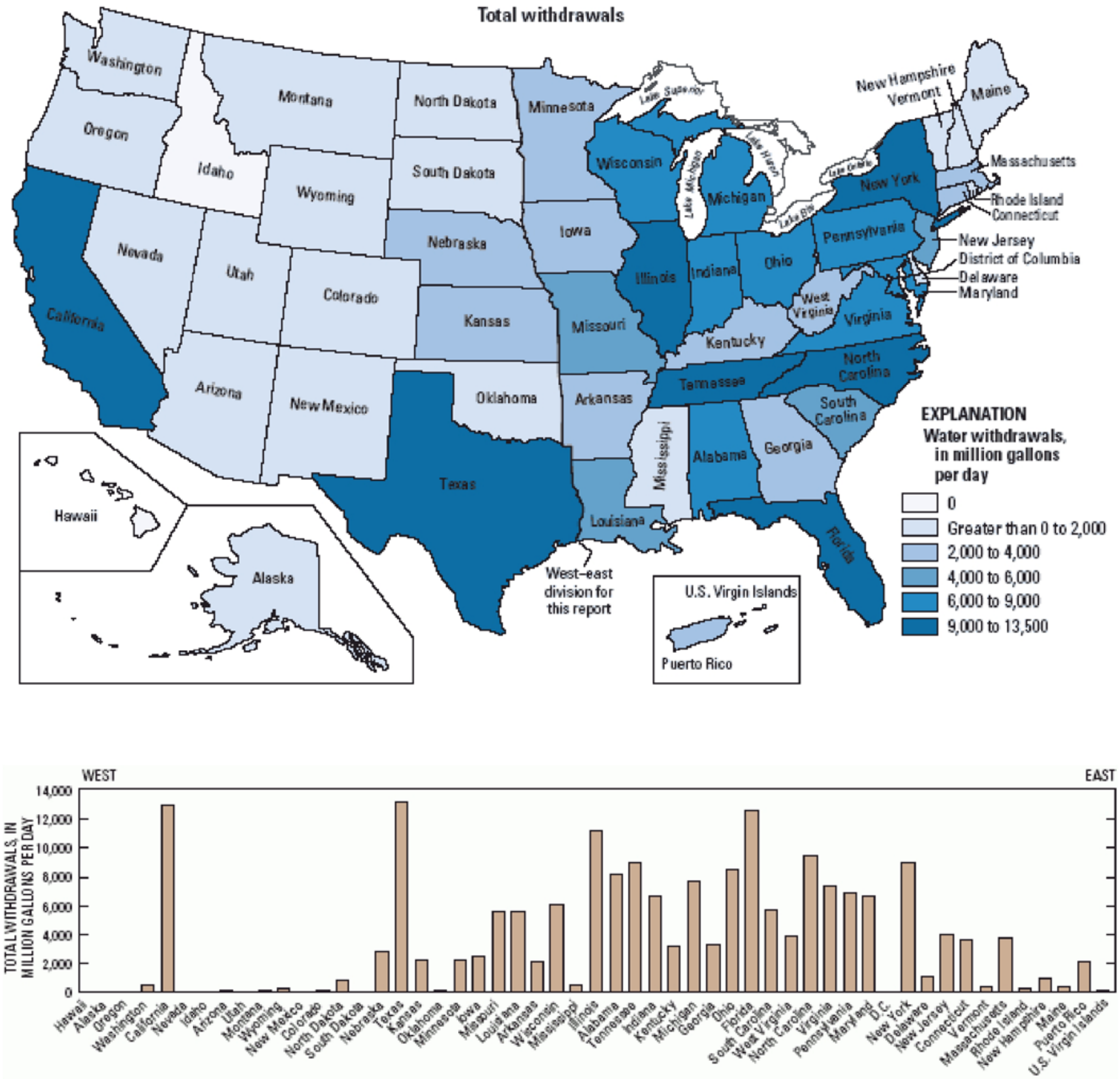
[4] SRBC 2011.

[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

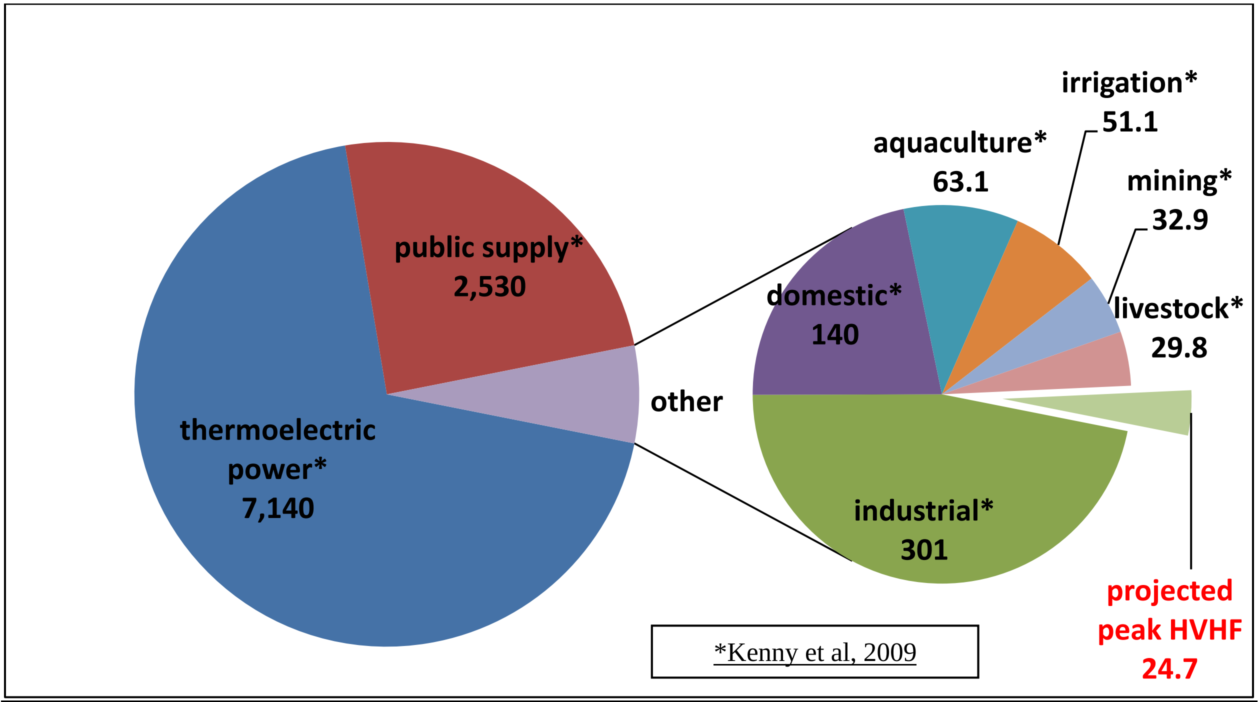
ALPHA GEOSCIENCE

Alpha Project No. 09104

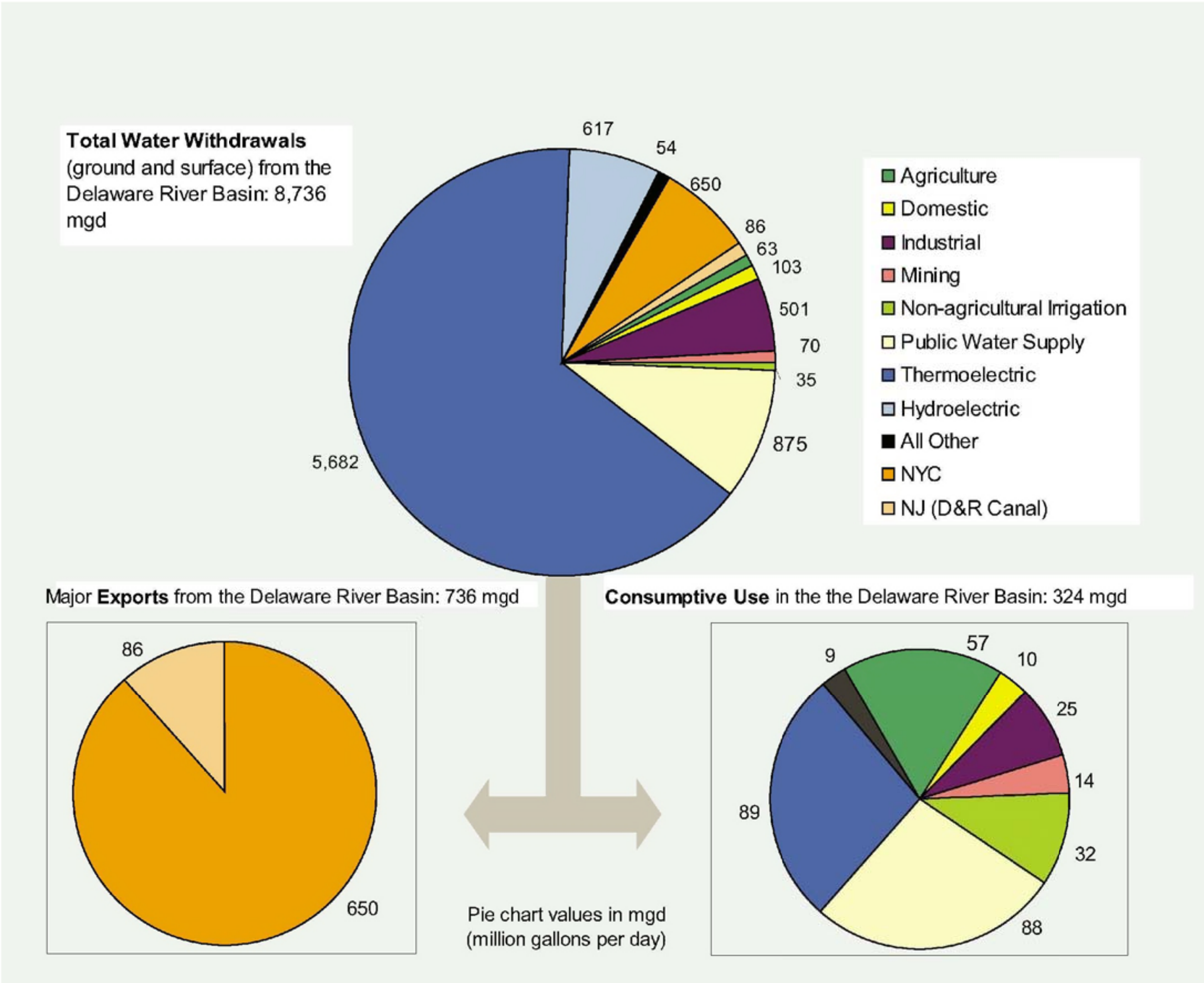
Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

Map Document: (Z:\projects\2009\09100-09120\09104 - Gas Well Permitting GEIS\Figures\Canvas\Fig3-2-NY_Water_Usage.cvx)

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.



Source: DRBC

FIGURE 6.3

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

ALPHA GEOSCIENCE
Alpha Project No. 09104

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

Map Document: (Z:\projects\2009\09100-09120\09104 - Gas Well Permitting GEIS\Figures\Canvas\Fig3-3-DRBC.cvx)

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, piping 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-Butanetricarboxylicacid, 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-eicosene	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-Nitriloprionamide / 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-propenamide, 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 / Progargyl Alcohol	Yes					0.05
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13,7]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, Ditallow alkyl, ethoxylated	Yes					§§
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates	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]
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, tetratpropylene 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

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]
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, diquaternary 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					§§

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]
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	Ethyloctynol	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					§§

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]
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 napthenic 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.

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]
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					§§

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]
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	polyethlene 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-(phenylmethl),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	Syntthetic 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.

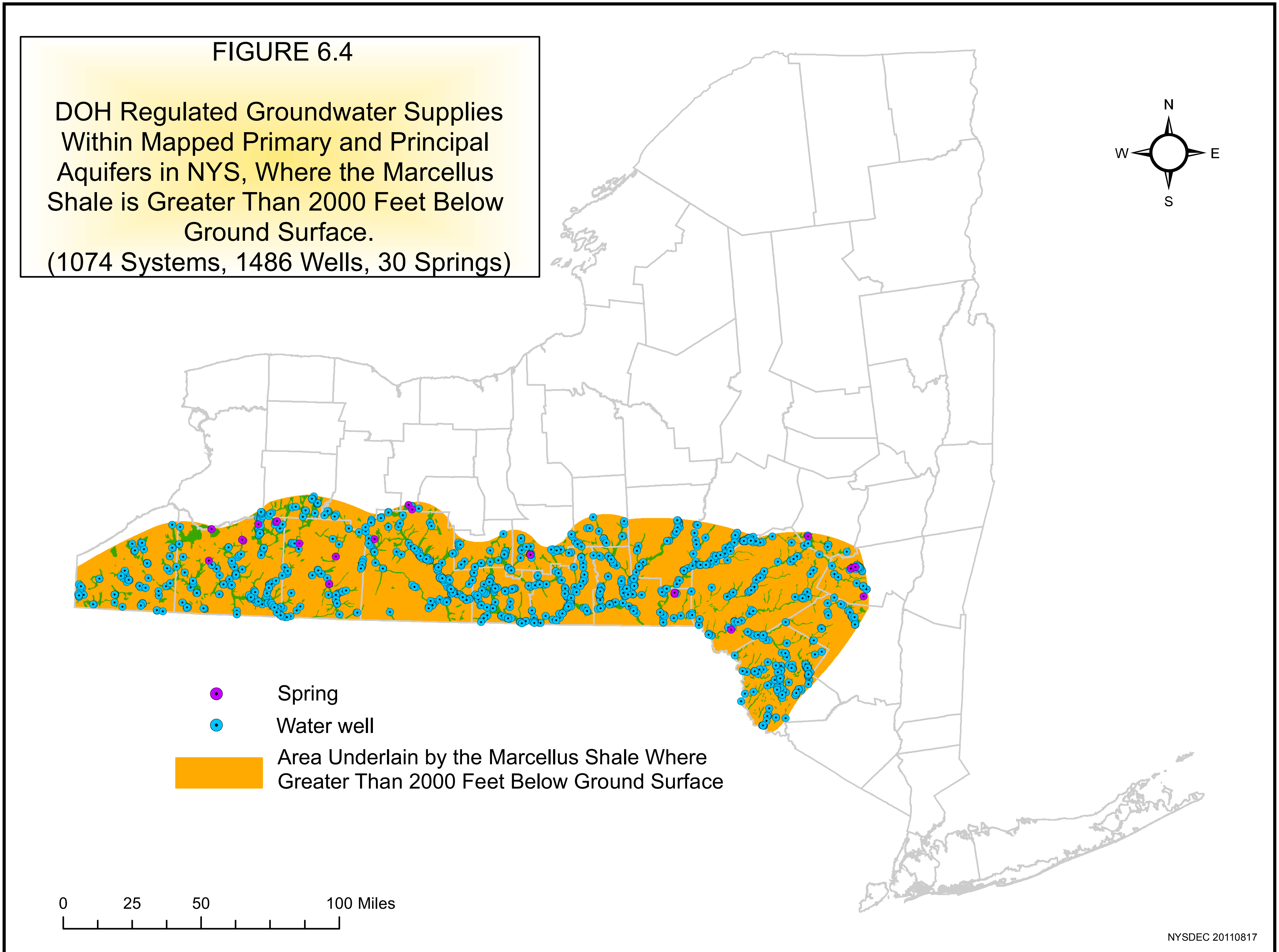
FIGURE 6.4
DOH Regulated Groundwater Supplies Within Mapped Primary and Principal Aquifers in NYS, Where the Marcellus Shale is Greater Than 2000 Feet Below Ground Surface.
(1074 Systems, 1486 Wells, 30 Springs)
N
W
E
S
Spring
Water well
Area Underlain by the Marcellus Shale Where Greater Than 2000 Feet Below Ground Surface
0
25
50
100 Miles
NYSDEC 20110817

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 x 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 H_2S 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, P*redicting 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, NYSERDA 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 x 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 NYSERDA, 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

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

where K= permeability, A= cross sectional area, P=pressure, μ=fluid viscosity and L=length of flow. The factor "$P_{high}-P_{low}$" 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 ($CaCO_3$);
- 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 2008[45] 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 2002[46] 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 trend (%/year)	New York population remaining (%)	USFWS Region 5 trend (%/year)	USFWS Region 5 population remaining (%)	Survey-wide trend (%/year)	Survey-wide 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**

[1]Highest priority or [2]High 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) forested[51] 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.

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[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 2010[55] 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]

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[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 Context[57] (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.

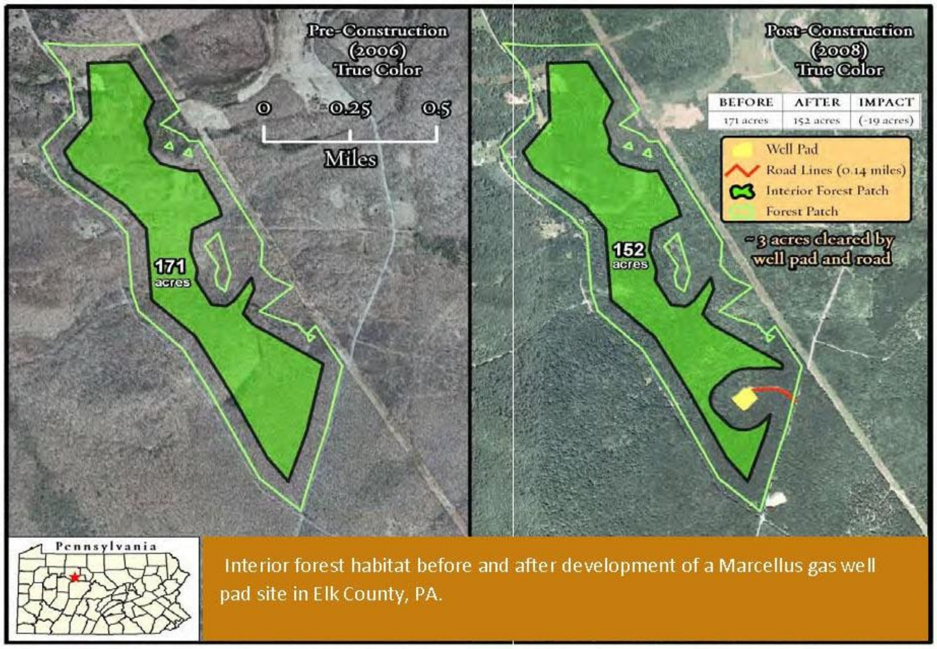


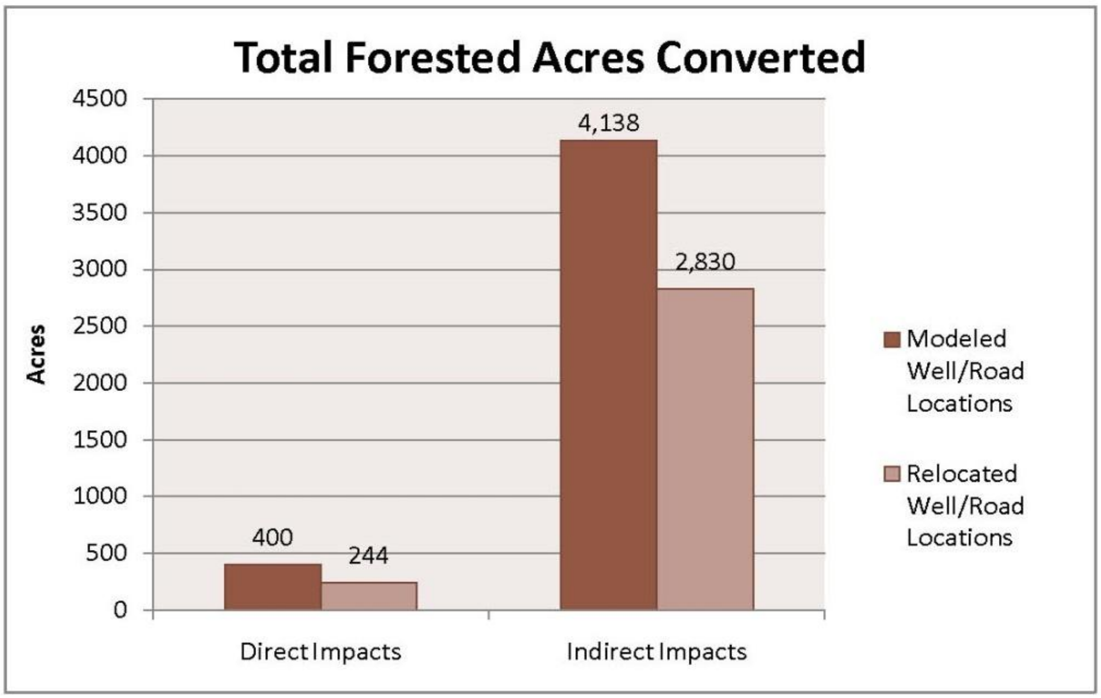
Figure 6.6 – Interior Forest Habitat Before & After Development of a Marcellus Gas Well Pad, Elk County PA[60] (New July 2011)

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 Converted[61] (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 2010[63] 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.

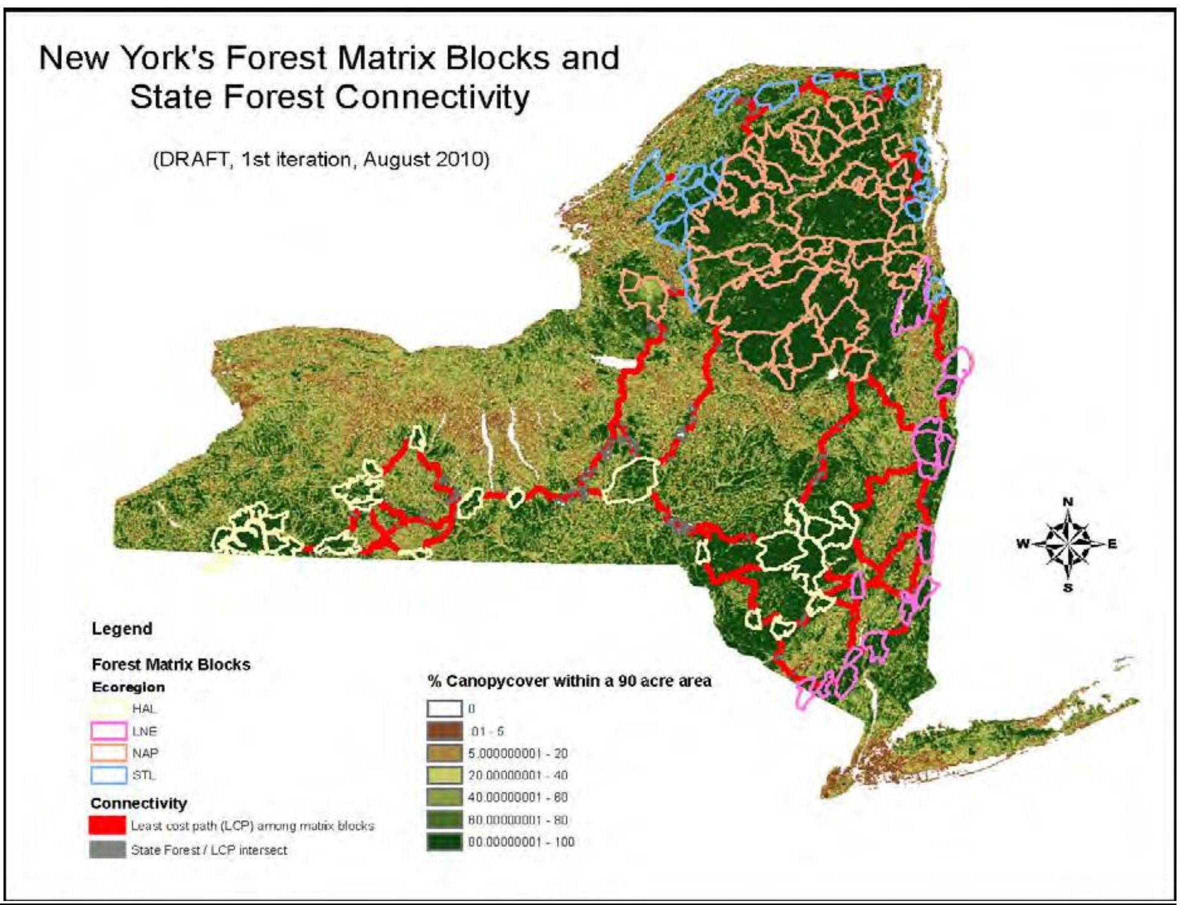
[62] TNC 2004.

[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 Connectivity[64] (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 invasive[66] 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	*Alliaria petiolata*
Mugwort	*Artemisia vulgaris*
Brown Knapweed	*Centaurea jacea*
Black Knapweed	*Centaurea nigra*
Spotted Knapweed	*Centaurea stoebe* ssp. *micranthos*
Canada Thistle	*Cirsium arvense*
Bull Thistle	*Cirsium vulgare*
Crown vetch	*Coronilla varia*
Black swallow-wort	*Cynanchum louiseae* (*nigrum*)
European Swallow-wort	*Cynanchum rossicum*
Fuller's Teasel	*Dipsacus fullonum*
Cutleaf Teasel	*Dipsacus laciniatus*
Giant Hogweed	*Heracleum mantegazzianum*
Japanese Stilt Grass	*Microstegium vimineum*
Terrestrial - Vines	
Common Name	**Scientific Name**
Porcelain Berry	*Ampelopsis brevipedunculata*
Oriental Bittersweet	*Celastrus orbiculatus*
Japanese Honeysuckle	*Lonicera japonica*
Mile-a-minute Weed	*Persicaria perfoliata*
Kudzu	*Pueraria montana* var. *lobata*
Terrestrial – Shrubs & Trees	
Common Name	**Scientific Name**
Norway Maple	*Acer platanoides*
Tree of Heaven	*Ailanthus altissima*
Japanese Barberry	*Berberis thunbergii*

[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	*Elaeagnus angustifolia*
Autumn Olive	*Elaeagnus umbellata*
Glossy Buckthorn	*Frangula alnus*
Border Privet	*Ligustrum obtusifolium*
Amur Honeysuckle	*Lonicera maackii*
Shrub Honeysuckles	*Lonicera morrowii/tatarica/x bella*
Bradford Pear	*Pyrus calleryana*
Common Buckthorn	*Rhamnus cathartica*
Black Locust	*Robinia pseudoacacia*
Multiflora Rose	*Rosa multiflora*

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 invasive[69] 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	*Cabomba caroliniana*
Rock Snot (didymo)	*Didymosphenia geminata*
Brazilian Elodea	*Egeria densa*
Water thyme	*Hydrilla verticillata*
European Frog's Bit	*Hydrocharis morus-ranae*
Floating Water Primrose	*Ludwigia peploides*
Parrot-feather	*Myriophyllum aquaticum*
Variable Watermilfoil	*Myriophyllum heterophyllum*
Eurasian Watermilfoil	*Myriophyllum spicatum*
Brittle Naiad	*Najas minor*
Starry Stonewort (green alga)	*Nitellopsis obtusa*
Yellow Floating Heart	*Nymphoides peltata*
Water-lettuce	*Pistia stratiotes*
Curly-leaf Pondweed	*Potamogeton crispus*
Water Chestnut	*Trapa natans*
Emergent Wetland & Littoral	
Common Name	**Scientific Name**
Flowering Rush	*Butomus umbellatus*
Japanese Knotweed	*Fallopia japonica*
Giant Knotweed	*Fallopia sachalinensis*
Yellow Iris	*Iris pseudacorus*
Purple Loosestrife	*Lythrum salicaria*
Reed Canarygrass	*Phalaris arundinacea*
Common Reed- nonnative variety	*Phragmites australis* var. *australis*

[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.

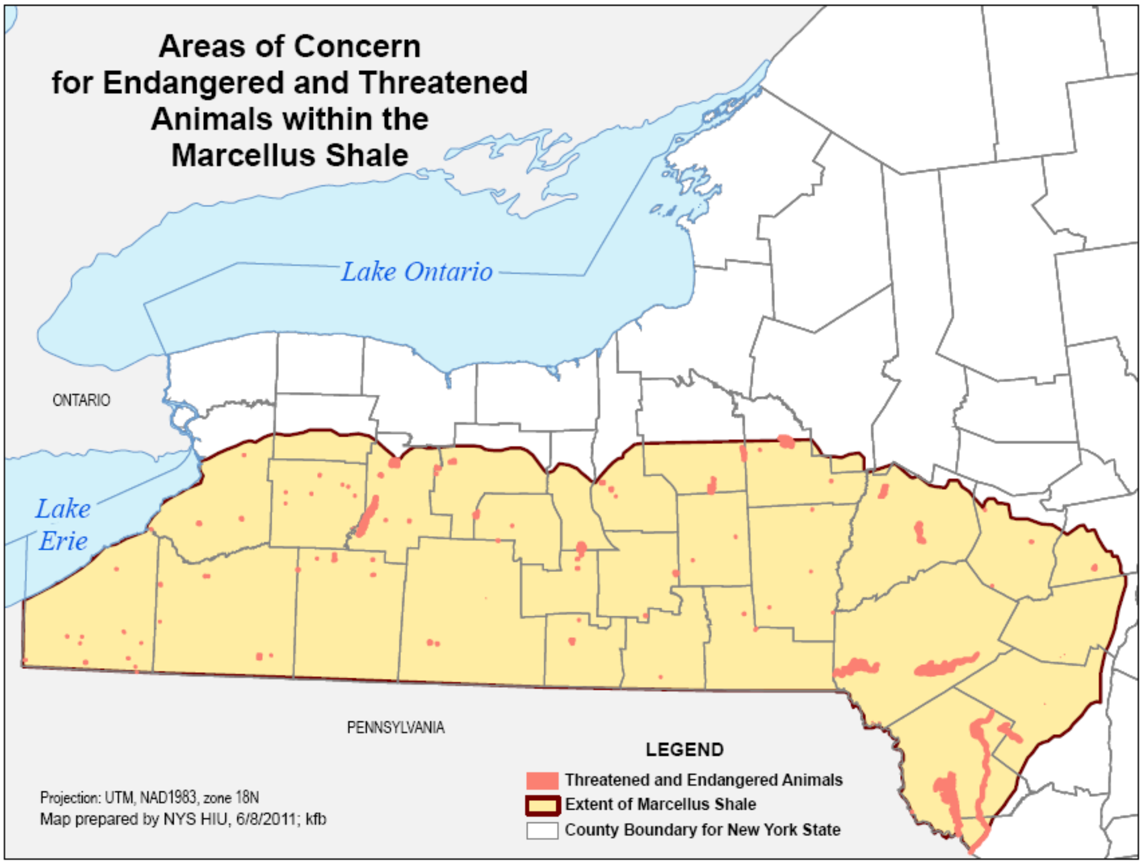
Endangered and threatened wildlife may be adversely impacted through project actions such as clearing, grading and road building that occur within the habitats that they occupy. Certain species are unable to avoid direct impact due to their inherent poor mobility (e.g., Blanding's turtle, club shell 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	*Ammodramus henslowii*	Threatened	Grassland
Short-eared Owl	*Asio flammeus*	Endangered	Grassland
Upland Sandpiper	*Bartramia longicauda*	Threatened	Grassland
Northern Harrier	*Circus cyaneus*	Threatened	Grassland, wetlands
Sedge Wren	*Cistothorus platensis*	Threatened	Grassland
Peregrine Falcon	*Falco peregrinus*	Endangered	Cliff faces
Bald Eagle	*Haliaeetus leucocephalus*	Threatened	Forest, open water
Least Bittern	*Ixobrychus exilis*	Threatened	Wetlands
Pie-billed Grebe	*Podilymbus podiceps*	Threatened	Wetlands
Eastern Sand Darter	*Ammocrypta pellucida*	Threatened	Streams
Mooneye	*Hiodon tergisus*	Endangered	Large Lakes, Rivers
Longhead Darter	*Percina macrocephala*	Threatened	Large Streams, Rivers
Brook Floater	*Alasmidonta varicosa*	Threatened	Streams and Rivers
Wavyrayed Lampmussel	*Lampsilis fasciola*	Threatened	Small, Medium Streams
Green Floater	*Lasmigona subviridis*	Threatened	Small, Medium Streams
Clubshell	*Pleurobema clava*	Endangered	Small, Medium Streams
Rayed Bean	*Villosa fabalis*	Endangered	Small Streams
Timber rattlesnake	*Crotalus horridus*	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 (O_3), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), fine particulate matter (PM10 and PM2.5), 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 O_3 precursors (NO_x and VOC) and direct PM2.5 and its precursor emissions (SO_2 and NOx). 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: SO_2 Emissions. Subpart LLL governs emissions of SO_2 from gas processing plants, specifically gas sweetening units (remove H_2S and CO_2 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 "**s**tate 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 NOx.

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:

NO_x emissions = (6.4 g/Hp-hr) × (5400 Hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 333.7 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:

NO_x emissions = (6.4 g/Hp-hr) × (2333 Hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 144.1 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).

NO_x emissions = (2.0 g/Hp-hr) × (2500 Hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 48.3 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, SO_2, 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 H_2S. 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 requests[76] (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.

[76] 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 became 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 PM2.5 ambient standard and the adoption of new 1-hour SO_2 and NO_2 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 PM2.5 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 NYSERDA[79] 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 H_2S. 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 H_2S to SO_2 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 PM2.5 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 PM2.5 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

EPA[82] and Department[83] 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 SO_2, NO_2, 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 O_3 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 O_3 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 gage 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 comments[85] 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

[85] AKRF 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 SO_2 emissions from flaring of H_2S 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 NO_2 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 (H_2S) 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 H_2S) 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 flame 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 SO_2- 3-hour, 24-hour, and annual; for PM10/PM2.5 - 24-hour and annual; for NO_2 - 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 PM2.5, 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 SO_2, NO_2 and PM10. More recently, EPA finalized the PSD increments for PM2.5; 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 SO_2 and NO_2 NAAQS which are addressed in the supplemental modeling section. Furthermore, the final PSD increments for PM2.5, 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 PM2.5, 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 NO_2 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 PM2.5 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 monitoredbackground levels for the non-criteria pollutants modeled, the impacts of H_2S 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 PM2.5. Thus, most do not need to be updated. On the other hand, for PM2.5 24-hour averages and the new 1-hour NO_2 and SO_2 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 NO_2 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 NO_2 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 NO_2 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 SO_2 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 PM2.5 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., 99^{th} 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 PM2.5 and the annual NO_2 were re-calculated for the compressor and line heater, as noted in Table 6.16. In addition, due to the promulgated PSD increments for PM2.5 in the 10/20/10 final rule, the increments are reflected in Table 6.16, along with the corresponding PM2.5 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 PM2.5 impacts. In fact, the 3-hour (and very likely the annual) SO_2 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 NO_2 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 µg/m3 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 $\mu g/m^3$), 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 NO_2 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 NO_2 and 24-hour PM2.5 were essentially the same; in fact the 24-hour PM2.5 impacts are identical to the previous maxima while the NO_2 annual impact of 63.2 increased by only 1.2 µg/m^3. 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 PM2.5 and 1-hour NO_2 NAAQS would substantially reduce both the PM2.5 and NO_2 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/m^3 (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 μg/m^3 for H_2S (underlined top entry in the box) is above the New York standard of 14 μg/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 (3 0 ft) would be necessary to reduce the impact to the 12.1 μg/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 PM2.5, SO_2 and NO_2 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 PM2.5 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 SO_2 and NO_2 which became effective since September 2009. The modeling performed previously for PM10/PM2.5 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 PM2.5. 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 PM2.5 exceedances and the associated mitigation measures necessary to assume NAAQS compliance.

In addition to the PM10/PM2.5 issue, EPA promulgated new 1-hour standards for SO_2 and NO_2. These standards are 100 ppb (or 188 $\mu g/m^3$) for NO_2, as the 3 year average of the 98th percentile of the daily maximum 1-hour values and 75 ppb (or 196 $\mu g/m^3$) for SO_2, 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, respectively[89]. 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 analysis[90]. The analysis was based on one year of Binghamton meteorological data which indicated compliance with the PM10 NAAQS and much lower PM2.5 impacts than the Department's results, but still exceedances of the PM2.5 NAAQS. Mitigation measures were listed for resolving the latter exceedances. The analysis incorporated a set of assumptions which are summarized below with the Department's position on each of these:

The PM emissions provided by ALL consultants in the Industry Information Report were not speciated with respect to PM10 and PM2.5. Based on factors in EPA's AP-42 for large uncontrolled diesel engines, the PM10 and PM2.5 emissions represent 82% and 69%, respectively, of the total PM emissions. The Department has reviewed the information and agrees that the corresponding emissions should be adjusted accordingly;

The set of 15 completion equipment engines were represented in the Department's modeling as three sets of 5 units stationed next to each other. Industry noted that since these units contributed significantly to the modeled exceedances, each of the engines should be model as a separate point source. The Department had noted this conservative step and has remodeled the units are 15 separate sources. However, unlike Chesapeake's approach of separating the 15 units in two sets at the extreme ends of the pads, the Department has no reason to believe the engines would not be placed next to each other. Thus, the engines are re-modeled as depicted in revised Figure 6-5;

[90] June 21, 2010 letter from Brad Gill of IOGA-NY to Kathleen Sanford and associated modeling files.

It is claimed that the use of ULSF would result in an additional 10% reduction in PM emissions. The Department could not readily verify the level of reduction specifically for all diesel fuel sulfur contents, but it has been considered in our discussion of resultant impacts;

It was notes that the maximum emissions provided for the completion equipment engines are only representative of two hours in the operation cycle of these units. Thus, the hourly emission rate in the modeling was "prorated" to better characterize the likely 24-hour emission rate. The Department does not agree with this approach. As noted in our previous analysis, the ALL report noted a typical hydraulic fracturing operation can require up to 10 stages of total 5 hour periods. Thus, it is likely that a relevant portion of a day could experience the maximum hourly emission rate associated with worst case impacts, as we had previously assumed. Since there is no justified or simplified approach to account for this possibility, we believe it prudent to use the maximum hourly emission rate for the revised analysis; and

It was noted that for drilling engines, the use of the EPA "capping" stack option is not appropriate since the cap is "open" when the engines are in operation. This assumption has been revised in the reassessment by using the actual stack velocities and temperatures.

Finally, the Chesapeake modeling report noted that the background levels used were the maxima observed at representative monitors and are unreasonably high. The SGEIS recognizes the conservative nature of the background levels chosen as worst case observations, but notes that more representative values can be determined in instances where such refinement is necessary. For PM2.5, the reassessment has taken a less conservative approach in accord with the Department's and EPA's modeling guidance by reviewing the monitoring data and the expected associated average values in the Marcellus Shale area. In its March 23, 2010 guidance memo[91] on PM2.5, EPA provided a screening first Tier conservative approach to addressing NAAQS compliance which was to be followed by further guidance with more refined methods.

Lacking the follow-up guidance, most states, including New York, have allowed methods more in line with Section 8.2 of EPA's Modeling Guidelines. One such approach recognized by the March 23, 2010 memo is to allow for seasonal average observed concentrations. In reviewing

[91] Modeling Procedures for Demonstrating Compliance with PM2.5 NAAQS, Stephen Page, 3/23/10.

the data at monitors in the Marcellus Shale area, especially for the latest three years, we have identified a value of 15 μg/m^3 as appropriate for the purpose of determining representative 24-hour "regional" background level. The data also indicates that more recent observations than the 2005-7 levels in the SGEIS have in general shown a downward trend. It is also noted that the modeled impacts would dominate the total impacts which are to be compared to the NAAQS. For this reason, it is deemed appropriate to use the 8th highest concentration, as the form of the NAAQS, instead of the maximum 24-hour value recommended as a first screening Tier. A conservative step was to use the 8th highest maximum from each year of meteorological data modeled since these were limited to only two years per site.

In addition to these modifications to the original PM10 and PM2.5 modeling in the SGEIS, we have incorporated industry's assertion that there would not be simultaneous drilling and hydraulic fracturing operations at a single well pad. In order to better characterize the contribution of the completion equipment engines, the drilling rig engine and the air compressors, in addition to calculating the maximum overall impacts, the modeling results were also separated for each operation to determine the need for mitigation associated with each engine type. The modeling approach was otherwise identical to the previous analysis, except the version of AERMOD was updated to the version (09292) available at the time of the analysis.

The first step in the modeling exercise was to determine the maximum 24-hour PM10 and PM2.5 impact for each of the modeled years. These results are presented in Table 6.18. It is seen that the refined impacts which incorporate the above considerations are much lower than the values in Table 6.15. This reduction is due mainly to the speciated emission rates and the modeling of completion equipment engines as individual point sources. However, the impacts are still projected to be above the PM10 and PM2.5 NAAQS, except for the PM10 impacts associated with the drilling engines. As was noted previously, these maximum impacts occur next to the well pad and concentrations drop-off relatively sharply with downwind distance. The modeled impacts were reviewed and indicate that impacts above the NAAQS-minus-background levels value occurred at distances up to a maximum of 60m for completion equipment engines and PM10, while for PM2.5 the corresponding maximum distances were 120 and 150m for the drilling and completion equipment engines, respectively. The levels of the maximum impacts also indicate that the different sets of engines could be dealt with using different mitigation measures.

As required by Part 617.11(5) (see next section for more details), the Department would pursue mitigation measures which eliminate potential adverse impacts to the maximum extent practicable. The August 26, 2009 industry report, the Industry Information Report and technical information from the public[92] identified a set of such potential measures which have been reviewed with this SEQRA requirement in mind. Certain of these suggestions would unlikely be practically implemented to any extent; for example, the use of electric engines could be very limited due to the remote nature of the drilling sites, while cleaner fuel engines are currently being investigated by engine manufacturers for future use. To the extent these alternative cleaner engines are available, the Department recommends their use. On the other hand, PM control equipment or the use of newer and cleaner engines are two measures recognized by both industry and the public as viable and the Department's review has concluded that these measures are practical. Appendix 18A provides the Department's review of the emission factors for various tiers of engines and potential after-treatment methods. Its conclusions are incorporated in the following discussions.

The discussions are limited to PM2.5 since these are the controlling impacts; that is, any measures to eliminate the PM2.5 exceedances would also assure compliance with the PM10 NAAQS. For the drilling rig and air compressor engines, the results in Table 6.18 were further analyzed to determine the impacts from each. The contribution to the overall maximum impact (Buffalo, 2007) for drilling operations was associated with the rig engines. Furthermore, industry has suggested and operational diagrams confirm that these engines are used close to the center of the well pad where the drilling actually occurs. The modeling results in Table 6.18 indicate that at a distance of 75m (from the center to the edge of the well pad) the drilling engine impacts are 30 $\mu g/m^3$, essentially due to the rig engine, which would still require mitigation when a background level of 15 $\mu g/m^3$ is used. Even if the 10% reduction in PM emissions due to the use of ULSF is achieved, as argued by industry, the resultant impact would still exceed the NAAQS. The rig engine impacts, however, are associated with ALL report's assumed Tier 1

[92] For example, comments by AKRF consultants on behalf of NRDC, Memorandum from Hillel Hammer, dated December 3, 2009, page 5.

engine emission factor. If the rig engines class was restricted to the use of Tier 2 and higher, then the PM2.5 impacts would be reduced by at least a factor of 2.7 (see Table Two of Appendix 18A, 0.4/0.15) which would result in compliance with the NAAQS regardless of where these engines are located on the well pad.

Industry data in the IOGA-NY information responses indicate that a majority (71%) of engines currently in use are Tier 2 and Tier 3 engines. In addition, a small fraction (3.5%) are uncertified (Tier 0), with "unknown" emissions. It is the Department's conclusion that these latter engines cannot be used for drilling in New York's Marcellus Shale since it has not been demonstrated that these would result in NAAQS compliance. Furthermore, since 25% of the current drilling engines are Tier 1, their use in New York should only take place with certain control measures. The discussions in Appendix 18A conclude that of the two exhaust after-treatment measures, Diesel Oxidation Catalyst (DOC) and Continuously Regenerating Diesel Particulate Filter (CRDPF) or particulate "traps", the latter is by far the more effective method in that it achieves almost three times the emission reduction (i.e., 85% vs 30%). The level of control achieved by the traps is necessary to alleviate all PM2.5 NAAQS exceedances from any Tier 1 drilling engines. Thus, the CRDPF traps should be the after-treatment for Tier 1 drilling engines if these are to be used in New York. This conclusion also applies to the air compressors for which the maximum PM2.5 impact is calculated to be 65ug/m^3 for Tier 1 emissions. On the other hand, Tier 2 and above drilling rig engines and air compressors demonstrate NAAQS compliance without these controls.

The Department also considered the "mitigation" of the NAAQS exceedances by stack height and distance restriction measures identified previously in the SGEIS. Although the IOGA-NY response also lists the stack height increase on the drilling engines as a potential measure, there is no indication from industry if such measures are practical given the stack configuration of these engines and the height to which these would be extended. In addition, this measure is not in strict accord with the need to mitigate the adverse impacts to the maximum extent practicable. The combination of operating these engines closer to the drilling rig, but more importantly the use of CRDPF traps on Tier 1 engines are deemed the necessary mitigation measures.

Turning next to the completion equipment engines, it seems even less practical to apply the distance and stack height increase restrictions to this class of engines. In fact, industry has previously indicated that stack height increase on these mobile units cannot be practically accomplished. A modeling run indicates that in order to meet the PM2.5 standard under the revised set of assumptions, the stack height would need to be at least doubled. Furthermore, the distance at which impacts are projected to be below the NAAQS-minus-background level was noted previously to be 150m. This is based on the Tier 2 emission factor modeled for these engines as provided by the ALL report. Consequently, the required practical approach to these engines would also require the use of the CRDPF traps as after-treatment on Tier 2 engines. For the maximum 24-hour PM2.5 case of Table 6.18 (Buffalo, 2006), the 202 $\mu g/m^3$ impact reduces to 44 $\mu g/m^3$ at a distance of 75m from the engines. Again, a 10% reduction in PM emissions due the use of ULSF does not alleviate these exceedances. Furthermore, unlike the smaller drilling engines, the ability of placing the 15 completion equipment engines (typically 14 used in Pennsylvania) near the center of the well pad is questionable. Based on industry's depiction, it is possible to separate these into two sets at either side of the hydraulic fracturing operations to further reduce impacts. In sum, however, the number of Tier 2 completion equipment engines which would require the installation of the particulate traps ranges from at least two thirds to all of the 15 engines per hydraulic fracturing job. For practical purposes, it is recommended that all Tier 2 engines be equipped with the CRDPF traps. Otherwise, each well operation might need to undergo more site specific analysis to demonstrate that a certain configuration or PM trap installation alternative would assure compliance with the 24-hour PM2.5 and PM10 NAAQS. Further details on the practicality of requiring these traps and other after-treatment control measures are discussed in the section following the SO_2 and NO_2 modeling results.

With respect to the Tier 0 and Tier 1 completion equipment engines, these emissions have not been analyzed or modeled, but for the same reasons as for the drilling engines, Tier 0 completion equipment engines should not be used in New York. In addition, based on the scaling of the maximum impact in Table 6.18 by the ratio of Tier 1 to Tier 2 emission factors (2.7), it is determined that Tier 1 engines have the potential to cause a modeled exceedance even if equipped with a particulate trap (maximum impact of 82 $\mu g/m^3$ with 85% control). Industry can suggest impact mitigation in addition to the use of PM traps in order to show compliance with the NAAQS, but lacking such a demonstration, it is the Department's interim conclusion that Tier 1 completion equipment engines should not be used in New York. On the other hand, and as also suggested by industry and the public, newer Tier 4 engines, which would likely be equipped with traps in order to achieve the required emission factors for those engines, can be used as an alternative to the Tier 2 engines with a PM trap.

B) SO_2 and NO_2 1-hour Impacts and Potential Mitigation Measures.

The 1-hour SO_2 and NO_2 NAAQS were promulgated since September 2009. Permitting and SEQRA actions after the effective date of an NAAQS are addressed by the Department to assure compliance with the NAAQS in accord with standard Department and EPA policy and requirements. EPA Region 2 recommended that the Department consider the new NAAQS in the SGEIS. In accord with the SEQRA process and the Department's Subpart 200.6 requirement, the Department has modeled the 1-hour SO_2 and NO_2 impacts to assure that all NAAQS are met.

With respect to the 1-hour SO_2 standard of 196 $\mu g/m^3$, no detailed modeling was determined necessary. Instead, the results of the previous SO_2 3-hour modeling in Table 6.15 indicated that the use of the ULSF would likely result in 1-hour impacts being below the NAAQS. Thus, the 1-hour maximum CO impact in Table 6.15 was used to scale the corresponding 1-hour maximum SO_2 impacts using the ratio of the fracturing engine SO_2 and CO emissions since these engines were responsible for the overall maxima. The resultant maximum impact is calculated to be 24 $\mu g/m^3$. Using a representative, yet conservative, maximum 1-hour SO_2 level of 126 $\mu g/m^3$ from the Elmira monitor for 2009 gives a total impact of 150 $\mu g/m^3$ which is below the corresponding NAAQS of 196 $\mu g/m^3$. Thus, no further modeling was necessary to demonstrate compliance with the 1-hour SO_2 standard.

Simple scaling to demonstrate compliance was not possible for the NO_2 1-hour impacts due to the very large concentrations projected using the same method. Instead, it was necessary to account for a number of refinements in the modeling based on EPA and Department guidelines. There are at least two main aspects to the NO_2 modeling which need to be addressed in such refinements. These issues have been raised by EPA, industry and regulatory agencies as needing further guidance. Similar to the PM2.5 guidance, EPA released a memorandum[93] on June 29, 2010 which provides guidance on how to perform a first Tier assessment for the NO_2 NAAQS. More recently, EPA has provided further guidance [94]on particulars in the modeling approach for NO_2 1-hour NAAQS compliance determinations.

The two main issues which have been raised deal with: 1) the form of the standard, as the 3 year average of the 98% of the daily maximum 1-hour value, which the AERMOD model used for the original modeling and the revised PM2.5 modeling are not set to calculate, and 2) the ratio of NO_2 to NO_x emissions assumed for stacks from various source types. Of these, the latter is more critical since NO_2 is a small fraction of the NO_x emissions in essentially all source types and assuming all of the NO_x emissions are NO_2 is unrealistic. These issues, however, are not insurmountable. For example, there are model post processors offered by consultants which can readily resolve the first issue. At the time of our re-analysis, EPA provided the Department with a “beta” version of AERMOD which performs the correct averages for NO_2. Some limited preliminary supplemental modeling used that model version, but the Department has recalculated these impacts using the final version of AERMOD (11059) released on 4/8/11 to assure proper calculation of the 8th highest 1-hour maximum per day of meteorological data. The results discussed below reflect the use of this version of AERMOD. It should be noted that the revised version of AERMOD does not contain any changes significant enough to affect the PM2.5 analysis.

With respect to the second issue, a number of entities, including EPA and the Department, have gathered information on the NO_2 to NO_x ratios from various source types which can be incorporated in the modeling. For the specific drilling and completion equipment engines, Department staff has undertaken a review of available information and has made recommendations on this issue. The details of the recommendations are provided in Appendix 18A which are used in the analysis to be discussed shortly. In addition to this ratio, EPA and Department guidance allows the use of two methods to refine NO_2 modeled impacts; the Ozone

[93] *Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program.* Memo from Stephen Page, EPA OAQPS, dated June 29, 2010.

[94] *Additional Clarifications Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS.* Memo from Tyler Fox, EPA OAQPS, dated March 1, 2011.

Limiting Method (OLM) and the Plume Volume Molar Ratio Method (PVMRM). There is no preference indicated in EPA guidance as to which method might provide more refinement. However, based on limited model evaluation results presented in the March 1, 2011 EPA guidance memorandum, the current analysis has relied upon the OLM method with the appropriate "source group" option (OLMGROUP ALL) noted in the EPA memo.

In addition to the NO_2/NO_x ratio, hourly O_3 data is necessary for the use of the method. These were taken from available Department observations at monitor sites representative of the meteorological data bases discussed in the original analysis section. Furthermore, for the determination of background 1-hour NO_2 values, we have refined EPA's first Tier screening approach of using the highest observed levels by calculating the average of the readily available 3rd- highest observations from the Department's Amherst and Pinnacle State Park monitors for the year 2009. This calculated value is 50 $\mu g/m^3$ and is still conservative relative to the form of the NO_2 standard, as well as relative to further refinements allowed by EPA and Department guidance.

Appendix 18A recommends that, for engines for which emissions were calculated by the Industry Information Report and used in the Department's modeling, the NO_2 fraction of NO_x is 11% without after-treatment. Thus, an initial set of model runs were performed for the completion equipment engines using the two years of Albany data and this ratio of 0.11 in AERMOD. The results indicate that the maximum impacts from the hydraulic fracturing operations with the 0.11 factor (without the OLM approach) were approximately 3500 $\mu g/m^3$ which, although lower than those from the simple scaling of the CO impacts, are still an order of magnitude above the 1-hour standard of 188 $\mu g/m^3$ for the hydraulic fracturing operations. The impact was noted to be above the NAAQS out to a distance of 300 m from the pad. Thus, further refinements were necessary by the AERMOD-OLM approach.

First to consider, however, is that a confounding issue which this initial modeling did not include was the discovery that the NO_2 to NO_x ratio is increased by the particulate trap from 0.11 to 0.35 due to the generation of NO_2 in order to oxidize and remove the particulates (see Appendix 18A). This would lead to even higher NO_2 impacts. These results clearly indicate that some form of after-treatment exhaust control method is necessary for the completion equipment engines. The after-treatment methods to reduce NO_x emissions are discussed in Appendix 18A which indicates that at present the recommended exhaust treatment method in practical use for on-road engines or engines in general is the SCR system. As noted in Appendix 18A, this preferred after-treatment method for NO_x control would reduce the NO_2 to NO_x ratio (with the CRDPF traps in place) down to essentially the same value as without the traps (i.e. 0.10). Of course, the SCR system would also substantially reduces the NO_x emissions by 90%. Therefore, the last step in the modeling of the completion equipment engines was to use the 90% reduction in emissions and the NO_2/ NO_x ratio of 0.10 with the OLM option. The analysis relied on the Tier 2 emissions provided by the Industry Information Report as the base emissions which were then reduced by 90% by the SCR controls. This level of modeling was deemed the most refinement allowed currently by Department and EPA guidance.

For the drilling engines, an initial modeling was performed first without the SCR controls and the 0.11 NO_2/NO_x ratio and the drilling rig Tier 1 emissions provided in the Industry Information Report as representative of the maximum emission case. For the compressors, Tier 2 was provided as the worst case emissions for the modeling of short term impacts. Based on two years of Albany meteorological data, it was found that the rig engines would exceed the NO_2 1-hour standard by about a factor of two and impacts would be above the NAAQS-minus-background level out to a distance of 150 m. From the modeling for PM2.5, it was found that the Tier 1 rig engines would need to be equipped with a PM trap in order to project compliance with the 24-hour PM2.5 standard. Since the traps were found to increase the NO2/ NO_x ratio by three fold, it is clear that the Tier 1 rig engine impacts would be substantially above the 1-hour NO_2 NAAQS without reductions in the NO_2 emissions. Thus, it is concluded that any Tier 1 rig engines (and compressors by analogy) would need to be equipped with both a PM trap and SCR for use in New York drilling activities.

Thus, the final set of modeling analysis used the SCR controlled Tier 2 completion equipment engine emissions with a NO_2/NO_x ratio of 0.10 and Tier 2 drilling rig engines and air compressor engines (both of which do not require PM traps) with the NO_2/ NO_x ratio set to 0.11 as noted previously. As for the completion equipment engines, the NO_2 modeling for the rig engines and compressors was based on more realistic representation of the units as individual units of five separate, but contiguous point sources as a further refinement to represent their configuration.

The emissions for each were scaled from the totals in Table 8 of the 8/26/09 Industry Report and these were placed in a north-south orientation at the same location as in Figure 6-2.

The set of NO_2 modeling with all of the meteorological data sites considered all potential sources as in previous analysis, but also provided the maximum impact for each of the three types of engines in order to determine specific potential necessary mitigation measures. However, initial modeling of the combined “drilling” scenario using two years of Albany data indicated an inconsistence in the total projected impacts in comparison to the results from the rig engines and compressors separately. This raised a potential issue with the “combined” impacts from these two operations which was related to the specifics of the OLM Ozone “distribution” approach. The resolution of this issue for the purposes of determining impacts from the rig engines and compressors and the need for potential mitigation measure was to recommend to place these two types of engines near the rig in the center of the well pad (as in the case of the PM results) and, furthermore, to separate these on either side of the drill rig to minimize combined impacts. A single year model run indicated this minimized combined impacts. From information and diagrams available, it is clear that these engines are in fact placed near the center of the pad when in actual operation.

The results of the 1-hour NO_2 impacts are presented in Table 6.18. As noted in the table, all engine are based on Tier 2 emissions, with the completion equipment engines assume to use SCR controls. The results for each of the meteorological data years, the overall maxima, the impacts at a 75-m distance (from center of pad to boundary), and the distance at which the impacts fall off to the NAAQS-background value of 138 $\mu g/m^3$ are presented for the completion equipment engines, the rig engines and the compressors. It is seen that the overall maxima are above the NAAQS. However, these need to be qualified relative to the other information tabulated in terms of potential mitigation measures necessary. It should be noted that a number of conservative assumptions are related to these impacts. First, it is noted that if the sources are placed in the center of the pad, as recommended, the impacts are much lower and essentially below the 1-hour NAAQS. Furthermore, these impacts should be adjusted downward by 10% since the tiered emission “limits” for Tier 2 and above are at most 90% NO_x as described in Appendix 18A. In addition, the background level used is conservative in that it represents the average of the third highest observations in the shale area and can be adjusted downwards.

Lastly, the distance to achieve the NAAQS minus background level is seen in the Table to be very close to the edge of the well pad. Using concentration maps for the three engine types indicate a sharp drop off of impacts such that the NAAQS minus background level is reached essentially at the well pad edge with only the 10% downward adjustment to impacts. In total, these considerations result in the NO_2 impacts being below the 1-hour NAAQS with the proper placement of the engines near the center of the well pad and the use of SCR control on the fracturing engines, coupled with Tier 2 or higher engines.

As discussed in Appendix 18A, SCR control is the only currently available NO_x reduction system for these size engines which has demonstrated the ability to practically achieve the level of reduction necessary (i.e., minimum 90%) to meet the NAAQS. Since the results of the PM2.5 modeling concluded that Tier 0 (uncertified) and Tier 1 completion equipment engines are not recommended for use in New York if CRDPF (particulate traps) are retrofitted to these, the application of SCR to Tier 2 and newer engines were considered. It is the Department's understanding from the manufacturers of these engines that the Tier 4 engines would have to be equipped with PM traps and SCR in order to meet the more stringent emission limits. It should be recalled that without the SCR control, the particulate traps increase the NO_2 to NO_x ratio by three fold and the corresponding impacts by a similar magnitude. Thus, the SCR system should be installed on all engines in which PM traps are being required for PM2.5 NAAQS compliance purposes. Any alternate system proposed by industry which has a demonstrated ability to achieve the same level of PM and NO_x reduction and, concurrently, resolve the NO_2 increase by the particulate traps in order to meet the NAAQS would be considered by the Department. At the present time, the Department is not aware of such an alternative system which has a proven record. For the purposes of the SGEIS, the Department has determined that the SCR system is necessary and adequate for this purpose. The next section discusses the practicality of using both the particulate traps and SCRs on completion equipment engines.

A summary of the Department's determination on the EPA Tier engines and the necessary mitigations to achieve the 24-hour PM2.5 and 1-hour NO_2 NAAQS is presented in tabular form in Table 6.19. The first column provides the various EPA tiers for the drilling and completion equipment engines and their time lines as presented in Appendix 18A. The next column presents sample percent of each Tier engines currently in use as provided by industry in the Information

Report. Note that based on the previous discussions, the uncertified (Tier 0) engines would not be allowed to be used in NY for Marcellus Shale activities. The third column provides the ratio of the Tier 1 emission rates for PM and NO_x to the other tiers, based on the information in Appendix 18A. The last column summarizes the determinations made by the Department on the control requirements necessary to meet the 24-hour PM2.5 (and PM10) and the 1-hour NO_2 ambient standards. As seen from the table, Tier 1 drilling engines and air compressors would require a PM trap and SCR controls, with the same controls being required on most of the completion equipment engine tiers.

Another purpose of this table is to provide an important demonstration that the Department's recommendations on control measure for these engines would result in substantial emission reduction over the current levels allowed in any other operations in other states. That is, in terms of air quality impacts, the emission reduction factor column of Table 6.19 indicates at least a factor of 3 and 2 reductions in PM2.5 and NO_2 emissions, respectively, from the Tier 1 engines. Thus, although Tier 2 and 3 drilling engines make up a majority of the engines in current use (71%), their relative emissions are much lower than the Tier 1 engines, which are recommended not to be used in NY (or have PM traps and SCR controls with about 90% reductions in emissions). Therefore, in terms of emissions reductions, the Department's requirements on the drilling engines would reduce emissions by at least half. Furthermore, since the completion equipment engines are about four times larger than the drilling engines, the imposition of PM traps and SCR on most completion equipment engines means a substantial reduction in overall PM and NO_x emissions from the set of engines to be used in New York. Any alternative emission reduction schemes which industry might further pursue would be judged against these reductions. It is clear however, that the Department would assure that any such control or mitigation measure would explicitly demonstrate compliance with the ambient air quality standards.

6.5.2.6 The Practicality of Mitigation Measures on the Completion Equipment and Drilling Engines.

The supplemental modeling assessment has concluded that in order to meet the ambient standards for the 24-hr PM2.5 and the 1-hour NO_2 NAAQS, it is necessary that the completion equipment engines tiers allowed to be used in New York to be equipped with particulate filter traps (CRDPF) and SCR control for NO_x. These are Tier 2 and newer completion equipment engines. Similarly, the Tier 1 rig engines and air compressors would be required to be equipped with both control devices if these are used in New York. The determination on the specific after-treatment controls was based on the review of available control methods used in practice (see Appendix 18A). Currently available alternative control measures considered were deemed inadequate for the purpose of achieving the level of PM2.5 and NO_x emission reductions necessary to demonstrate NAAQS compliance and/or having a proven record of use in practice.

Although industry can attempt to perform an independent assessment of alternatives to the recommended exhaust after-treatment controls, it is highly likely that a certain level of control equipment recommended would be necessary on these engines. If industry indentifies viable alternative control measure which can be demonstrated to achieve the same level of emission reduction for NAAQS standard compliance, these alternative schemes would need to be submitted for Department review and concurrence prior to their use in New York. Furthermore, in recommending the use of particulate traps and the SCR technology, Department staff has considered the requirements of subsection 617.11.5 and the practicality of the chosen measures.

Taking the diesel particulate traps and the SCR controls separately, it is fair to say that since the former have a longer established history of actual use than the latter on types of engines of size in the rig engine class, the demonstration of practicality for the traps might be less onerous. For example, industry itself has identified these diesel particulate traps on Tier 2 and 3 engines in their list of mitigation measure.[95] In addition, public information (see footnote 17) also has identified the ongoing use of diesel traps as a required mitigation measure by Metropolitan Transportation Authority (MTA) for non-road engines in major construction projects in NYC. These latter engines, however, are in the size range of the smaller rig engines and not in the completion equipment engine range. Information on the ongoing practical use of particulate traps in these and similar activities have been further confirmed by Department staff through publically available information. Thus, while it can be concluded that the requirement to use particulate traps on certain EPA tiered engines is in accord with Subsection 200.6 and 617.11 of the Department’s requirements, it is nonetheless necessary for industry to further assess the

[95] Page 43 of the ALL/IOGA September 16, 2010 Information Request Report.

practicality of their use for the completion equipment engine size range. Based on limited conversations with two of the engine manufacturers indicated that the main issue still to be resolved is the details of the engineering necessary to use PM traps as after-treatment equipment. The concern relates to the need for "stand alone" equipment for each of the completion equipment engines which differs from the built-in or add on components being currently used for the smaller on-road or off-road engines. To the Department's knowledge, currently neither PM and NO_2 control measures are being used by the gas drilling industry for other shale activities to any extent. However, it is the Department's assumption that the PM traps can be feasibly used on the Tier 1 drilling engines and compressors and the Tier 1 and 2 completion equipment engines.

For the use of SCR as the Department's preferred control measure to reduce NOx emissions from all of the completion equipment engines allowed to be used in New York, there is less information on similar size engines. As Appendix 18A notes, however, these units are widely used in a package with particulate traps on heavy duty vehicles and there is no operational reason that the same cannot be achieved with the larger completion equipment engines. One way to judge the practicality of using SCR control on these engines is to consider the costs involved. The Department has undertaken a simple approach to this issue by using the analogy to reducing exhaust stream NOx emission and its "cost effectiveness" as a means for major stationary sources to get a "waiver" from the emission control limits set forth in Subpart 227-2 (Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x)). That is, if a source can demonstrate that the costs associated with the imposed emission limits are unreasonable, the Department and EPA would consider granting a waiver from meeting these limits.

Details of an analysis of the "cost effectiveness" of the SCR controls for completion equipment engines and the comparable value currently used by the Department for stationary sources is provided in Appendix 18B. It is important to note that the "cost effectiveness" is based on acceptable "engine size scaling-up" method for the completion equipment engines with certain assumptions which might not be representative of the actual cost of installation of SCR after treatment. The calculations in Appendix 18B indicate that the cost of requiring SCR on the completion equipment engines is within the value used by the Department for stationary sources and is deemed reasonable. The cost effectiveness for the smaller drilling engines should be lower. It is recognized that the applicability of 227.2 RACT requirements are meant for major individual stationary sources, but it is also to be noted that the potential annual NO_x emissions from the sum total of engine use throughout the Marcellus Shale are rather large, as discussed in the next section. Based on the conversations with the engine manufacturers, the main concern with the installation of SCR as an after-treatment control relates again to the need for a "stand-alone" system on the completion equipment engines, with the added complexity that these systems would require "continuous" maintenance to achieve the level of reduction assumed in the Department's analysis. In addition, these discussions indicate that the cost associated with the installation of the PM traps and SCR are likely above those assumed by the Department. A calculation using the approach in Appendix 18C for PM after-treatment indicates that the "cost effectiveness" value is well above the value used for NO_x RACT waiver determinations. Thus, it is recommended that industry undertake a detailed assessment of the PM traps and SCR controls in addressing the Department's recommendations of these controls as the required mitigation measures on certain Tier drilling and completion equipment engines in order to demonstrate compliance with the 24-hour PM2.5 and 1-hour NO_2 NAAQS.

Based on the above discussions, the Department believes that the use of particulate traps and SCR controls are reasonable and practical in achieving the mitigation of potential adverse 24-hour PM2.5 and 1-hour NO_2 impacts, respectively. As noted previously, industry can present equivalent control measures and background information for further Department considerations. Regardless of the specific measure, however, it should be made clear that the Department is required to assure compliance with ambient standards with respect to any other control measures which could put forth by industry or the public. One of the mitigation "measures" noted by industry in their Information Report, at least for NO_x emissions, is to allow for the "natural" fleet turnover of the EPA tiers as these requirements would "kick-in" over time. This suggestion is not an acceptable scheme, given that none of the engines currently in use or contemplated are the interim Tier 4 engines, which become effective in 2011, based on the Department's knowledge and industry data. If industry is to advance such a mitigation scheme, it would submit an acceptable timeline which clearly sets out an aggressive schedule to implement the Tier 4 engines. Based on engine manufacturer's information, there is ongoing efforts to achieve the

Tier 4 emission standards before the 2014/15 timelines noted in Table 6.19. Such an implementation schedule can be tied to the specific tiered engine after-treatment controls required by the Department.

6.5.2.7 Conclusions from the Modeling Analysis

An air quality impact analysis was undertaken of various sources of air pollution emissions from a multi-horizontal well pad and an example compressor station located next to a typical site in the area underlain by the Marcellus Shale. The analysis relied on recommended EPA and Department modeling procedures and input data assumptions. Due to the extensive area underlain by the Marcellus Shale and other low-permeability gas reservoirs in New York, certain assumptions and simplifications had to be made in order to properly simulate the impacts from a "typical" site such that the results would be generally applicable. At the same time, an adequate meteorological data base from a number of locations was used to assure proper representation of the potential well sites in the area underlain by the Marcellus Shale in New York.

Information pertaining to onsite and offsite combustion and gas venting sources and the corresponding emissions and stack parameters were initially provided by industry and independently verified by Department staff. The emission information was provided for the gas drilling, completion and production phases of expected operations. On the other hand, emissions of potential additive chemicals from the flowback water impoundments, which were proposed by industry as one means for reuse of water, were not provided by industry or an ICF report to NYSERDA. Thus, worst-case emission rates were developed by the Department using an EPA emission model for a set of representative chemicals which were determined to likely control the potential worst case impacts, using information provided by the hydraulic fracturing completion operators. The information included the compounds used for various purposes in the hydraulic fracturing process and the relative content of the various chemicals by percent weight. The resultant calculated emission rates were shared with industry for their input and comment prior to the modeling.

The modeling analysis of all sources was carried out for the short-term and annual averages of the ambient air quality standards for criteria pollutants and for Department defined threshold levels for non-criteria pollutants. The initial modeling used limitations on simultaneous operations of the various equipment at both onsite and offsite operations for a multi-well pad in the analysis for the short-term averages, while the annual impacts accounted for the potential use of equipment at the well pad over one year period for the purpose of drilling up to a maximum of ten wells. For the modeling of chemicals in the flowback water, two impoundments of expected worst case size were used based on information from industry: a smaller on-site and a larger off-site (or centralized) impoundment.

Initial modeling results indicated compliance with the majority of ambient thresholds, but also identified certain pollutants which were projected to be exceeded due to specific sources emission rates and stack parameters provided in the Industry Information Report. It was noted that many of these exceedances related to the very short stacks and associated structure downwash effects for the engines and compressors used in the various phases of operations. Thus, limited additional modeling was undertaken to determine whether simple adjustments to the stack height might alleviate the exceedances as one mitigation measure which could be implemented. An estimate of the distances at which the impacts would reduce to below all applicable SGCs and SGCs were provided as part of the original analysis.

Based on recent information provided by industry on the operational restrictions at the well pad, the elimination of the flowback impoundments, and a limited modeling of 24-hour PM2.5 impacts, the initial Department assessment was revisited. In addition, due to the promulgation of new 1-hour SO_2 and NO_2 NAAQS after September 2009, further modeling was performed. The significant consequences of the revised restrictions on simultaneous operations of the drilling and completion equipment engines, the number of wells to be drilled per year, and the elimination of the impoundments are incorporated in the initial modeling assessment. Further modeling details for the short term PM2.5, NO_2 and SO_2 impacts are presented in a supplemental modeling section. These results indicate the need for the imposition of certain control measures to achieve the NO_2 and PM2.5 NAAQS. These measures, along with all other restrictions reflecting industry's proposals and based on the modeling results, are detailed in Section 6.5.5 as well permit operation conditions.

Table 6.12 - Sources and Pollutants Modeled for Short-Term Simultaneous Operations

Pollutant → Source	SO_2	NO_2	PM10 & PM2.5	CO	Non-criteria combustion emissions	H_2S and other gas constituents
Engines for drilling	✔	✔	✔	✔		
Compressors for drilling	✔	✔	✔	✔	✔	
Engines for hydraulic fracturing	✔	✔	✔	✔	✔	
Line heaters	✔	✔	✔	✔	✔	
Off-site compressors	✔	✔	✔	✔	✔	
Flowback gas flaring	✔	✔	✔	✔	✔	
Gas venting						✔
Mud-gas separator						✔
Glycol dehydrator					✔	✔

Table 6.13 - National Weather Service Data Sites Used in the Modeling

NWS Data Site	Meteorology Data Years	Latitude/Longitude Coordinates
Albany	2007-08	42.747/73.799
Syracuse	2007-08	43.111/76.104
Binghamton	2007-08	42.207/75.980
Jamestown	2001-02	42.153/79.254
Buffalo	2006-07	42.940/78.736
Montgomery	2005-06	41.509/74.266

Table 6.14 - National Ambient Air Quality Standards (NAAQS), PSD Increments & Significant Impact Levels (SILs) for Criteria Pollutants (μg/m^3)

Pollutant	1-hour	3-hour	8-hour	24-hour	Annual
SO_2 NAAQS	196	1300		365	80
PSD Increment		512		91	20
SILs		25		5	1
PM10 NAAQS				150	50
PSD Increment				30	17
SILs				5	1
PM2.5 NAAQS				35	15
PSD Increment				9	4
SILs[96]				1.2	0.3
NO2 NAAQS	188				100
PSD Increment					25
SILs					1.0
CO NAAQS	40,000		10,000		
SILs	2000		500		

[96] The PM2.5 standards reflect the 3 year averages with the 24 hour standard being calculated as the 98th percentile value.

Table 6.15 - Maximum Background Concentration from Department Monitor Sites

Pollutant	Monitor Sites	Maximum Observed Values for 2005-2007 ($\mu g/m^3$)
SO_2	Elmira* and Belleayre	3 hour - 125 24-hour - 37 Annual - 8
NO_2	Amherst	Annual - 26
PM10**	Newburgh* and Belleayre	24-hour - 49 Annual - 13
PM2.5	Newburgh* and Pinnacle State Park	24-hour - 30 Annual - 11 (3 year averages per NAAQS)
CO	Loudonville	1-hour - 1714 8 hour - 1112

* Denotes the site with the higher numbers.
** For PM10, data from years 2002-4 was used.

Table 6.16 - Maximum Impacts of Criteria Pollutants for Each Meteorological Data Set

Meteorological Data Year & Location		SO_2 3-hour	SO_2 24-hour	SO_2 Annual	PM10 24-hour	PM10 Annual	PM2.5* 24-hour	PM2.5* Annual	CO 1-hour	CO 8-hour	NO_2 Annual
Albany	2007	15.4	13.3	3.1	459	2.7	355	2.7	9270	8209	57.9
	2008	15.3	13.2	2.9		2.4		2.4	9262	8298	51.0
Syracuse	2007	15.9	12.6	2.8		2.7		2.7	8631	7849	57.1
	2008	15.8	14.3	2.7		2.7		2.7	8626	7774	55.4
Binghamton	2007	18.5	13.4	2.3		2.1		2.1	10122	8751	45.5
	2008	18.6	15.4	1.9		1.8		1.8	9970	8758	37.6
Jamestown	2001	16.7	14.0	2.4		2.1		2.1	8874	8193	46.4
	2002	16.8	14.4	2.7		2.3		2.3	8765	8199	50.9
Buffalo	2006	16.6	15.7	3.2		2.9		2.9	9023	8067	63.2
	2007	16.9	14.4	3.1		2.8		2.8	8910	8270	60.8
Montgomery	2005	17.4	11.6	1.9		1.8		1.8	9362	8226	38.4
	2006	14.4	14.0	2.2		2.0		2.0	9529	8301	41.9
Maximum		18.6	15.7	3.2		2.9		2.9	10122	8758	63.2
Impact at 500m		0.3	0.3	0.05	7.1	.11	5.0	.11	480	253	2.5

Note: 24-hour PM2.5 values are the 8th highest impact per the standard.

Table 6.17 - Maximum Project Impacts of Criteria Pollutants and Comparison to SILs, PSD Increments and Ambient Standards

Pollutant and Averaging Time	Maximum Impact ($\mu g/m^3$)	SIL*	Worst Case Background Level ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Increment Impact** ($\mu g/m^3$)	PSD* Increment ($\mu g/m^3$)
SO_2 - 3 hour	18.6	25	125	143.6	1300	18.6	512
SO_2 - 24-hour	15.7	5	37	52.7	365	15.7	91
SO_2 - Annual	3.2	1	8	11.2	80	3.2	20
PM10 - 24-hour	459***	5	49	508***	150	6.5**	30
PM10 - Annual	2.9	1	13	15.9	50	2.9	17
PM2.5 - 24-hour	355***	1.2	30***	385***	35	6.5**	9
PM2.5 - Annual	2.9	0.3	11	13.9	15	2.9	4
NO_2 - Annual	63.2	1.0	26	89.2	100	5.6**	25
CO - 1-hour	10,122	2000	1714	11,836	40,000	NA	None
CO - 8 hour	8758	500	1112	9870	10,000	NA	None

* SILs and increments for PM2.5 included in revised Table from EPA's final PSD rule for PM2.5

** Impacts from the off-site compressor plus the line heater only for PSD increment comparisons were recalculated for annual NO_2 and PM10 and PM2.5 24-hour cases. NA means not applicable

*** See Supplemental Modeling Section for revised analysis

Table 6.18 - Maximum Impacts of Non-Criteria Pollutants and Comparisons to SGC/AGC and New York State AAQS

Pollutant	Total Venting Emission Rate (g/s)	Impacts from all Venting Sources ($\mu g/m^3$)		All Combustion Sources and Dehydrator Impacts ($\mu g/m^3$)			
		Max 1-hr	SGC	Max 1-hr	SGC	Annual	AGC
Benzene***	0.218	140	1,300	13.2	1,300	0.90 0.10	0.13
Xylene	0.60	365	4,300	NA**	4,300	NA	100
Toluene	0.78	500	37,000	NA	37,000	NA	5,000
Hexane	9.18	5,888	43,000				
H_2S***	0.096	61.5 12.1	14*				
Formaldehyde**				4.4	30	0.20 0.04	0.06
Acetaldehyde				NA	4,500	0.06	0.45
Naphthalene				NA	7,900	NA	3.0
Propylene				NA	21,000	NA	3,000

* Denotes the New York State 1-hour standard for H_2S

** Denotes not analyzed by modeling, but the SGCs and AGCs would be met (see text)

*** AGC exceedance for benzene is eliminated by raising the dehydrator stack to 9.1m

The standard exceedance for H_2S is eliminated by using a minimum stack height of 9.1m for gas venting

The AGC exceedance for formaldehyde is eliminated by using a compressor stack height of 7.6m

Table 6.19 - Modeling Results for Short Term PM10, PM2.5 and NO_2 (New July 2011)

Met Data Location	Met Data Year	PM10, 24-hr (µg/m³)		PM2.5, 24-hr (µg/m³)		NO_2, 1-hour impact (µg/m³) (see NOTE)		
		Hydraulic Fracturing	Drilling	Hydraulic Fracturing	Drilling	Hydraulic Fracturing	Rig Engine	Compressor
Albany	2007	313	76	152	36	198	256	216
	2008	268	84	129	40	198	259	230
Syracuse	2007	224	95	144	34	156	196	198
	2008	327	81	120	27	161	180	208
Binghamton	2007	281	87	154	34	194	239	208
	2008	327	89	121	35	213	231	220
Jamestown	2001	339	74	151	29	180	237	221
	2002	229	83	155	33	181	248	217
Buffalo	2006	338	106	202	55	147	269	231
	2007	318	102	189	59	148	272	231
Montgomery	2005	255	77	104	28	169	198	202
	2006	301	66	108	21	155	211	200
Maximum (µg/m³)		339	106	202	59	213	272	231
Max @ 75m (µg/m³)		92	75	44	30	100-140	140-170	120-150
Max Dist to NAAQS - Background (m)		60	60	150	120	<90	<100	<100

NOTE: NO_2 results reflect SCR controls on the completion equipment engines, with Tier 2 emissions used for all completion equipment, rig engines and compressors. Results are from the OLM option in AERMOD. See text for details.

Table 6.20 - Engine Tiers and Use in New York with Recommended Mitigation Controls Based on the Modeling Analysis (New July 2011)

Engine Type (year in place)	Sample Percent in Use	Reduction factors in Emissions	Control measures considered and determined "practical" based on availability, use practice and cost.
Drilling: Tier 1 - 1996 (five @ 500hp)	25	Others relative to Tier 1	Would need PM traps and SCR.
Drilling: Tier 2 - 2002	49	2.7 1.6	No PM controls nor SCR necessary for NAAQS.
Drilling: Tier 3 - 2006	22	2.7 2.6	No PM controls nor SCR necessary for NAAQS.
Drilling: Tier 4 - Interim (not mandated) - 2011	0	40 5.1	Would likely have PM traps built in. No SCR necessary.
Drilling: Tier 4 - 2014	0	40 23.	Would have PM traps and SCR built in.
Completion: Tier 1 - 2000 (15 @ 2250 Hp)	Assumed same as for drilling	Others relative to Tier 1	Based on modeling, propose not to allow Tier 1 engines. Alternative is traps/SCR, plus more mitigation.
Completion: Tier 2 - 2006		2.7 1.6	Would need PM trap and SCR.
Completion: Tier 4 Interim - 2011		5.3 3.5	Would likely have PM traps and SCR built in or would use in-cylinder control for PM.
Completion: Tier 4 - 2015		13 3.5	Would have PM traps and SCR built in.

Note: 3.5% of engines in use are Uncertified or Tier "0". These will not be allowed to be used in NY

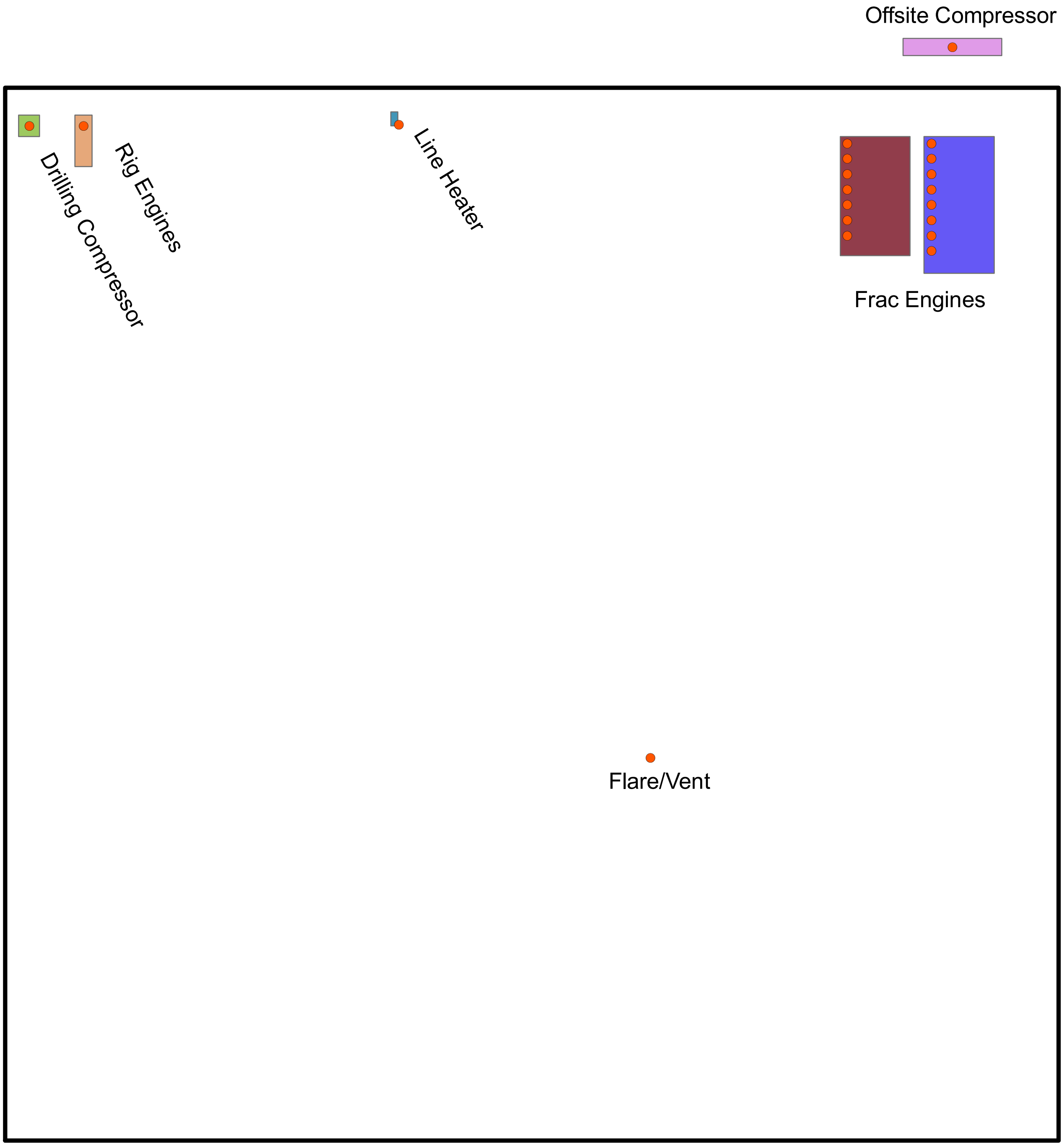
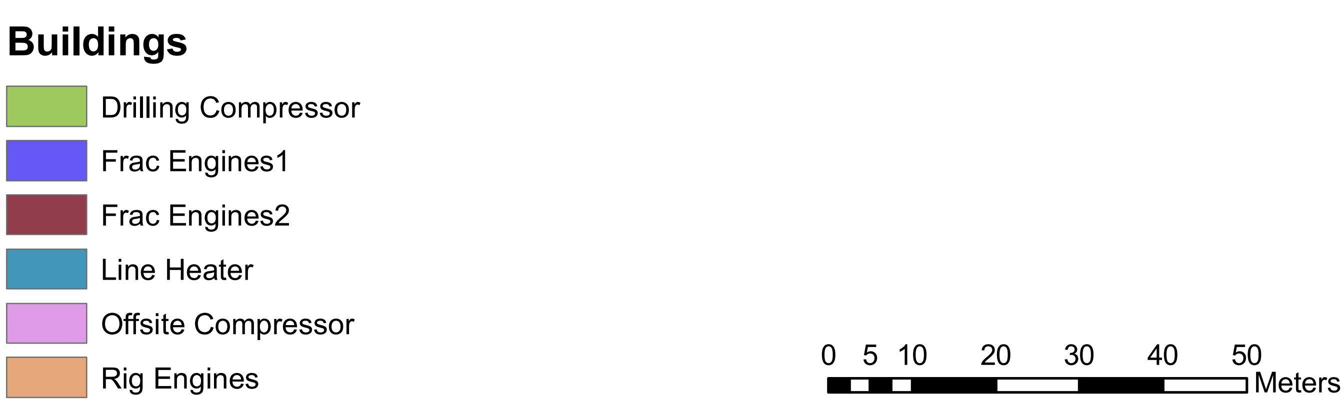


Figure 6.10- Location of Well Pad Sources of Air Pollution Used in Modeling



6.5.3 Regional Emissions of O_3 Precursors and Their Effects on Attainment Status in the SIP

This section addresses a remaining issue, as stressed by EPA Region 2[97] that the initial analysis did not provide a quantitative discussion of the potential regional emissions of the O_3 precursors, as contemplated in the Final Scoping for the 2009 draft SGEIS. The specific items relate to the impact of these drilling operations on the SIP for O_3 nonattainment purposes, as well as the impact of cumulative emissions from both stationary and mobile sources.

The initial analysis lacked information on the regional emissions of the cumulative well drilling activities in the whole of Marcellus Shale due to the lack of detail from industry on the likely number of wells to be drilled annually and associated emissions. It was determined that information and available data from similar shale development areas would not be suitable for a calculation of these emissions due to a variety of factors. Thus, the Department requested this emission information from industry and received the necessary data in the ALL/IOGA-NY Information Report referenced previously and in a follow-up request for mileage data for on-road truck traffic, as discussed below. The following narrative is intended to address concerns with the regional emissions as these relate to ozone attainment and similar SIP issues.

Attainment Status and Current Air Quality

The most recent nonattainment areas that have been designated by EPA are those for the 1997 8-hour ozone of 0.08 ppm (effectively 84 ppb), 1-hour ozone (0.12 ppm), annual and the 24-hour PM2.5 national ambient air quality standards (NAAQS) of 15 and 35 $\mu g/m^3$, respectively. In March 2008, EPA promulgated a revision of the 8-hour ozone NAAQS by setting the standard as 0.075 ppm. Nonattainment areas for the new standard have not as yet been established due to current efforts by EPA to reconsider a more restrictive NAAQS. EPA proposed its reconsideration of the 2008 ozone NAAQS in January 2010 taking comment on lowering the NAAQS to between 0.060 ppm and 0.070 ppm. EPA is expected to complete its reconsideration in July 2011.

Ozone and particulate matter are two of six pollutants regulated under the CAA as "criteria pollutants." Data from Department monitors through 2010 indicate that monitored air concentrations in the established nonattainment areas for O_3 and PM2.5, as well as in the area

[97] Comments of EPA Region 2 in letter from John Filippelli dated (12/30/09), pages 2-3.

underlain by the Marcellus Shale, do not exceed the currently applicable NAAQS. In addition, there are no areas in New York State that are classified as nonattainment for the remaining four criteria pollutants: CO, lead, NO_2 and SO_2. EPA has recently promulgated revisions to the lead, SO_2 and NO_2 NAAQS and has established new monitoring requirements for the lead and NO_2 NAAQS, as well as new modeling requirements for the SO_2 NAAQS. As a result of these new requirements, the Department cannot yet determine whether ambient air quality complies with these NAAQS values. However, the Department has proposed to EPA to classify the whole state as "unclassifiable" with respect to the NO_2 1-hour NAAQS and would have to submit a recommendation to EPA on SO_2 1-hour NAAQS. As data becomes available in the next few years, the Department would assess the data and recommend to EPA designation of all areas in the State as either attainment or nonattainment.

For O_3, the Department has a wealth of information to compare against the current, but delayed, 2008 NAAQS and the range of the reconsidered NAAQS. Under the 2008 Ozone NAAQS, current air quality in the Poughkeepsie-Newburgh, NYC and Jamestown metropolitan areas would make these areas nonattainment. If the O_3 NAAQS is set at the lower values proposed by EPA, more areas of the state, including those in the Marcellus Shale play, would also be nonattainment.

State Implementation Plans

The process by which states meet their obligations to improve air quality under the CAA, (for example, the applicable NAAQS for criteria pollutants) is established in SIPs. A major component of SIPs is the establishment of emission reduction requirements through the promulgation of new regulatory requirements that work to achieve those reductions. The combined effect of both state and federal requirements is to reduce the level of pollutants in the air and bring each nonattainment area into attainment. These requirements, which apply to both stationary and mobile sources, apply to both new and existing sources and are intended to limit emissions to a level that would not result in an exceedance of a NAAQS, thus preserving the attainment status of that area. In order to judge the potential effects of the projected O_3 and PM2.5 precursors in the Marcellus Shale on the SIP process, the Department has looked at the level of these emissions relative to the baseline emissions and has come to certain conclusions on the approach necessary to assure the goal of NAAQS compliance.

Projected Emissions and Current/Potential Control Measures

The primary contributors (emission sources) to ozone pollution include those that emit compounds known as "precursors" that result in the formation of ozone. The two most important precursors are NO_x and VOCs. PM2.5, another pollutant, is also directly emitted or formed from precursors, such as ammonia, sulfur oxides and NO_x. New York State and the federal government have promulgated emission rules that apply to the sources of these pollutants in order to protect air quality and prevent exceedances of the ambient air standards. In the case of Marcellus Shale gas resource development, most emissions resulting from natural gas well production activities are expected to come from the operation of internal combustion non-road engines used in drilling and hydraulic fracturing, as well as engines that provide the power for gas compression. Additional associated emissions occur with on road truck traffic used for transportation of equipment and hydraulic fracturing fluid components.

Engine emissions have long been known to be a significant source of air pollution. As a result, control requirements for these sources have been in place for many years, and have been updated as engine technology and control methods have improved. Regulations and limits exist on both the federal and state level, and effectively mitigate the effect of cumulative emissions on air quality and the SIP. In New York, these measures include:

Particulate Matter
Locomotive Engines and Marine Compression-Ignition Engines Final Rule
Heavy Duty Diesel (2007) Engine Standard
Part 227: Stationary Combustion Installations

Sulfur
Federal Nonroad Diesel Rule
6 NYCRR Part 225: Fuel Composition and Use

NO_x & VOCs
Part 217: Motor Vehicle Emissions
Part 218: Emission Standards for Motor Vehicles and Motor Vehicle Engines

Part 248: New York State Diesel Emissions Reduction Act (DERA)

Small Spark-Ignition Engines

Federal On-board Vapor Recovery

In addition, to address mobile sources emissions which might occur due to diesel trucks idling during the drilling operations, Subpart 217-3 of the New York State ECL specifically addresses this issue by limiting heavy duty vehicle idling to less than five consecutive minutes when the heavy duty vehicle is not in motion, except as otherwise permitted. Enforcement of this regulation is performed by Department Conservation Officers and violation can result in a substantial fine.

The above requirements for stationary sources apply statewide and not just in nonattainment areas due to New York's status as part of an Ozone Transport Region state. This differs from other areas such as the Barnett Shale project in which different standards apply inside and outside of the Dallas/Fort Worth nonattainment area. Furthermore, additional requirements and potential controls specific to the operations for the Marcellus Shale gas development were addressed in Section 6.5.1 with respect to the well pad and the compressor station (e.g., NSPS and NESHAPs requirements per 40 CFR 60, subpart ZZZZ and Part 63, subpart HH). Certain of these measures restrict the emissions of O_3 precursors to the maximum extent possible with current control measure. In addition to the mandatory requirements that are in place as a result of the above rules that directly affect the types of emissions that are expected with the development of Marcellus Shale gas resources, there are a number of other recommended measures that have been incorporated in previous sections to further reduce the emissions associated with these operations and mitigate the cumulative impacts:

1. NO_x emission controls (i.e., SCRs) and particulate traps on all diesel completion equipment engines and on older tier drilling engines (see section 6.5.2);

2. Condensate and oil storage tanks should be equipped with vapor recovery units (see section 6.5.1.5); and

3. The institution of a fugitive control program to prevent leaks from valves, tanks, lines and other pressurized production operations and equipment (see section on greenhouse gas remediation).

Use of controls for excess gas releases, such as flares by REC should be implemented wherever practicable (see section 6.5.2). In addition, other measures such as the use of more modern equipment and electric motors instead of diesel engines, where available, are recommended.

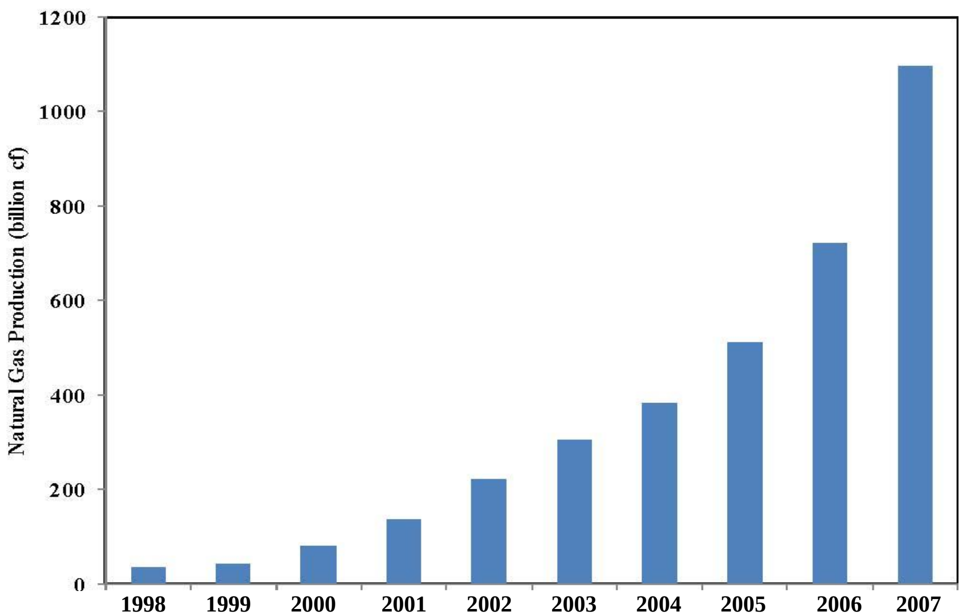
Regional NO_x and VOC Emission Estimates and Comparison to Estimates from another Gas-Producing Region

In order to assist the Department to develop a full understanding of the cumulative and regional emissions and impacts of developing the gas resources of the Marcellus Shale, available information from similar activities in other areas of the country has been reviewed. Notably, certain information from the Barnett Shale formation of north Texas, which has undergone extensive development of its oil and gas resources, was reviewed. The examination of the development of the Barnett Shale could be instructive in developing an approach to emissions control and mitigation efforts for the Marcellus Shale. As a result, the Department has examined one commonly referenced study and source of information on the regulation and control of air pollution from the development of the Barnett Shale.

First, the development of the gas resources of the Marcellus Shale, as with the Barnett Shale, not be spatially distributed evenly across the geographic extent of the region, but would likely concentrate in different areas at different times, depending on many factors and limitations, including the price of natural gas at any given moment, the ease of drilling one area versus another, and other legal/environmental constraints such as potential drilling in watersheds. As such, industry cannot project at this time as to where impacts may concentrate regionally within the Marcellus Shale region. Furthermore, well development would occur over time, wherein initially there would be a "ramping-up" period, followed by a nominal "peak" drilling period, and then a leveling off or dropping off period. Some of these factors and caveats are discussed in the ALL/IOGA-NY Information Report.

Thus, the cumulative impacts of gas well drilling within the Marcellus Shale would also vary depending on what point in time those impacts are measured as the development of the gas resource expands over time. As an example of how well development proceeded in the Barnett Shale, the Figure 6.11 indicates that gas production rose dramatically from 1998-2007. This chart is being used by the Department for illustration purposes only to indicate the timeframes which might be involved in the Marcellus development and not as an actual indication of expected development. Preliminary information from Pennsylvania indicates a more rapid increase in gas well drilling and production.

Figure 6.11 - Barnett Shale Natural Gas Production Trend, 1998-2007[98]



As drilling activities "ramp up," the potential for greater environmental impacts likewise increase. In estimating the air emissions of drilling in the Marcellus Shale, a worst case (conservative) scenario of drilling and development was developed by IOGA-NY in response to an information request from the Department. The estimates are provided in the ALL/IOGA-NY Information Report. There are a number of caveats associated with these estimates so the absolute magnitudes of emissions should be interpreted accordingly. However, an estimate of worst case emissions are projected for the maximum likely number of wells (2216) to be drilled in the Marcellus Shale for the "peak" year of operations and the emission factors and duration of operations provided in the previous industry report (8/26/09) used in the modeling assessment.

[98] Taken from Armendariz (SMU), 2009, p. 2.

Some of the factors which were included in the estimates noted in the ALL/IOGA-NY Information Report include:

- Average emission rates for dry gas are used for every well for every phase of development;
- Maximum number of wells (both horizontal and vertical) in any year;
- No credit is taken for any mitigation measures, permit emissions controls, or state and federal regulatory requirements that are expected to reduce these estimates;
- Drilling emissions are conservatively estimated at 25 days for the horizontal wells;
- Heater emissions are included year-round in the production estimates; however,they would be seasonal and would take place during the non-ozone season;
- Off-pad compressor emissions are included in the production estimates; however, it is anticipated that most well pads would not include a compressor;
- No credit is taken for the rolling nature of development; i.e., that all wells would not be drilled or completed at the same time, on the same pad;
- No credit is taken for improved nonroad engine performance and resultant reduced NO_x emissions from the higher tier engines that would be phased in over time; and
- No credit is taken for reduced emission completions which would significantly reduce flaring and hence related NO_x and VOC emissions.

The ALL/IOGA-NY Industry Information Report predicted the ozone precursor emissions depicted in Table 6.21.

Table 6.21 - Predicted Ozone Precursor Emissions (Tpy)

	Drilling	Completion	Production	Totals
Horizontal - NO_x	8,376	5,903	8,347	22,626
Vertical - NO_x	409	345	927	1,681
Total NO_x	8,785	6,248	9,274	24,307
Horizontal - VOC	352	846	5,377	6,575
Vertical - VOC	17	81	597	695
Total VOC	369	927	5,974	7,270

It is seen that the total for NO_x emissions for the horizontal wells is made up of 37% each from drilling and production and 26% from completion. It is to be noted that for the latter emissions, about half is associated with potential flaring operations. For VOC emissions for the horizontal wells, the production sources dominate (82% of total). This is related to the dehydrator emissions assumed to operate for a full year. It is also noted that the completion VOC emissions are due to venting and flaring. Based on the above numbers, IOGA-NY concluded the impact from the development of the Marcellus at a worst-case peak development rate would add 3.7% to existing NO_x emissions on a statewide basis. This was based on the 2002 baseline emission inventory (EI) year used in New York's 2007 SIP demonstration for the 8-hr ozone standard[99]. A more germane comparison would be to the "upstate" area emissions where Marcellus Shale area is located. This comparative increase would be 10.4% for the same EI year. These upstate area emissions exclude the nine-county New York ozone nonattainment area, as well as the counties north and east of the area underlain by the Marcellus Shale.

The total NO_x emissions increase from this example is deemed significant, but does not account for the number of mitigation measures imposed and recommended in the revised SGEIS. For example, the use of SCR control to reduce NO_x emissions by 90% from the completion equipment engines would reduce the completion emission by about half, while the minimization of flaring operations by the use of REC would reduce the rest of these completion emissions down to a very small value which would significantly reduced the relative percentage. In addition, as noted by the IOGA-NY Information Report, the production sources used in the estimates of NO_x emissions are not likely to be used the full year and might not be even needed at many wells. Furthermore, the estimated drilling emissions assume the maximum number of days would be needed for each well and the associated use of older tier engines throughout the area and over the long-term. Thus, the relative percent of Marcellus well drilling emissions to the existing baseline is highly likely to be substantially less than the value above using the worst case estimates.

The IOGA-NY also concluded that the total VOC emissions of 7,270 Tpy from the development of the Marcellus Shale would add 0.54% to existing VOC emissions on a statewide basis. Using

[99] Ozone Attainment Demonstration for NY Metro Area - Final Proposed Revision, Appendix B, pp. 10-11 http://www.dec.ny.gov/chemical/37012.html.

the same baseline EI year as for NO_x, the relative increase for VOCs would be 1.3%. This increase is deemed small and also does not account for recommended mitigation measures such as the minimization of gas venting by REC.

The above NO_x and VOC relative emission comparisons do not include the contribution from the on road truck traffic associated with Marcellus Shale operations and which had to be estimated by the Department. The ALL/IOGA-NY Information Report included the light and heavy truck trips, but not the associated average mileage which is necessary to calculate emissions. Thus, the Department requested an average Vehicle Miles Traveled (VMT) for the two truck types and ALL consulting provided the data in a response letter.[100] Based on this information, the Department projected the NO_x and VOC emissions from on road truck as discussed in the next subsection.

Effects of Increased Truck Traffic on Emissions

The initial modeling analysis did not address on-road mobile source emissions resulting from the drilling operations, specifically, diesel truck emissions, except at the well pad. The Department has analyzed the impact of increased emissions from truck traffic in the Marcellus Shale affected counties. As part of this analysis, the Department utilized estimates of VMT provided by ALL Consulting/IOGA-NY in response to the Department's information request to determine the environmental impacts of project related truck emissions. Industry estimated that the weighted average one way VMT for both light and heavy duty trucks to be approximately 20 to 25 miles for both horizontal and vertical wells.

The Department used these estimated average VMT for heavy-duty and light-duty trucks and the number of truck trips contained in the ALL/IOGANY Information Report to calculate the total additional VMT associated with drilling activities. These VMT, along with other existing New York-specific data were input to the EPA's Motor Vehicle Emission Simulator (MOVES) model to estimate NO_x and VOC emissions for the various truck activities. EPA Region 2 commented on the SGEIS and requested the use of the MOVES model. As EPA's approved mobile source model, MOVES incorporates revised EPA emission factors for various on-road mobile source activities and associated pollutants. The resulting emissions support a comparison of how traffic directly related to the drilling operations impacts the overall mobile emissions that normally would occur throughout the Marcellus Shale drilling area.

The estimated emissions of NO_x and VOCs (and well as other pollutants) that result from the additional light and heavy duty truck traffic expected with Marcellus well drilling are detailed in Appendix 18C. The emissions for the counties in the area underlain by the Marcellus Shale are presented for both the existing baseline activities as well as those associated with the drilling activities. In addition, the absolute and percent differences which represent the additional truck emissions are shown.

The results show that the total NO_x and VOC emissions are estimated to be 687 and 70 Tpy, respectively, and are expected to increase the existing baseline emissions by 0.66% and 0.17%. The maximum increase for any pollutant is 0.8%. These increases are deemed very small. In addition, the traffic related NO_x and VOC emissions are noted to be small fractions of the corresponding increased emissions due to other activities associated with gas drilling, as summarized in the last subsection. For example, the traffic related NO_x emissions are about 3% of the total NO_x emissions given in the above mentioned summary table. A simple estimate of traffic related emissions of PM2.5 per pad, using the total emissions and the number of maximum wells is shown in Appendix 18C to be 0.01 Tpy which is comparable to the previously estimated pad specific PM2.5 emissions noted in the modeling section which was estimated with the EPA MOBILE6 model.

Based on these results, the Department concluded that the estimated truck related emissions would be captured during the standard development of the mobile inventories for the SIP. These estimates are also noted to be within the variability associated with the MOVES model inputs.

Comparison to Barnett Shale Emission

A referenced report[101] on the Barnett Shale oil and gas production prepared by Southern Methodist University (SMU) for the Environmental Defense Fund (EDF) has been noted as a source of emission calculation schemes and resultant regional emissions for that region of Texas. In terms of the projected emissions of NO_x and VOCs, while caution should be exercised in making comparisons between the two areas, a picture of emissions from the Barnett Shale may be a useful point of departure for understanding the magnitude and types of emissions to be expected with the development of the Marcellus Shale. The Department has not undertaken a review of the rationale or the methodologies used in the SMU report and is also aware of the Texas Commission on Environmental Quality (TCEQ)'s critique of the report.[102] Since the report, TCEQ has undertaken a detailed emission inventory development program to better characterize the sources and to quantify the corresponding emissions.

For the present purposes, it is necessary to provide a brief outline of the potential differences between the gas development activities and associated sources between the Barnett report and the industry projections for the Marcellus Shale. For example, the SMU report provided the relative amount of emissions from different source categories and corresponding NO_x and VOC emissions, as presented in Table 6.22 below. For comparison, the industry-provided emissions summarized above are 66.7 and 20 tons per day (Tpd) for NO_x and VOCs, respectively. However, the latter do not include some of the sources tabulated in the SMU report such that a straightforward comparison is not possible. Nonetheless, the SMU report notes that the largest group of VOC sources was condensate tank vents. Table 6.22 also indicates that fugitive emissions from production operations have a significant contribution to the VOC totals.

Table 6.22 - Barnett Shale Annual Average Emissions from All Sources[103]

Source	2007 Pollutants, Tons per day(Tpd)		2009 Pollutants, Tons per day (Tpd)	
	NOx	VOC	NOx	VOC
Compressor Engine Exhausts	51	15	46	19
Condensate And Oil Tanks	0	19	0	30
Production Fugitives	0	17	0	26
Well Drilling and Completion	5.5	21	5.5	21
Gas Processing	0	10	0	15
Transmission Fugitives	0	18	0	28
Total Daily Emissions (Tpd)	**56**	**100**	**51**	**139**

[103] Adapted from Armendariz (SMU), 2009 p. 24.

These might explain the differences in VOC emissions in that industry does not expect to use condensate tanks in New York due to the dry gas encountered in the Marcellus Shale. In addition, these tank emissions, if used, would be controlled by vapor recovery systems as noted in Section 6.5.2. In addition, all efforts would need to be made by industry to minimize fugitive emissions as recommended in the greenhouse gas emission mitigations section which would reduce concomitant VOC emissions.

The SMU report also provides charts which compare the total NO_x plus VOC emissions from the Barnett oil and gas sources to totals from on-road source categories in the Dallas-Fort Worth area, concluding that the former are larger than the on road emissions in some respects. However, these comparisons are not transferrable to the Marcellus Shale situation in New York not only because VOC emissions dominate these totals, but also since the comparisons are to a specific regional mix of sources not representative of the situation to be encountered in New York. On face value, the absolute magnitude of these total emissions is much larger than even a "worst-case" scenario for the Marcellus Shale.

Again, no firm predictions or projections can be made at this time as to where or when gas drilling impacts may concentrate regionally within the Marcellus Shale, but the Department would continue to avail itself of the knowledge and lessons learned from similar regional shale gas development projects in other parts of the country.

Further Discussions and Conclusions

There are stringent regulatory controls already in place for controlling emissions from stationary and mobile sources in New York. With additional required emission controls recommended in the revised SGEIS for the operations associated with drilling activities, coupled with potential deployment of further emission controls arising from upcoming O_3 SIP implementation actions, the Department is confident that the effect of cumulative impacts from the development of gas resources in the multi-county area underlain by the Marcellus Shale would be adequately mitigated. Thus, the Department would be able to continue to meet attainment goals that it has set forth in cooperation with EPA. In addition to eliminating the use of uncertified and certain older tier engines and requiring specific mitigation measures to substantially reduce PM and NO_x emissions in order to meet NAAQS, the Department would review the need for certain additional mitigation prior to finalizing the SGEIS. As part of the information, the Department is seeking from industry an implementation timeline to expedite the use of higher tier drilling and completion equipment engines in New York. Furthermore, as the Department readies for the soon to be announced revised O_3 NAAQS and potential revisions to the PM2.5 NAAQS, the need for imposing further controls on drilling engines not being currently required to be equipped with PM traps and SCR would be revisited. If it is determined that further mitigation is necessary, further controls would be required. The review would consider the relatively high contribution to regional emissions of NO_x from the drilling engines and result from regional modeling of O_3 precursors which would be performed in preparation of the Ozone SIP.

Regional photochemical air quality modeling is a standard tool used to project the consequences of regional emission strategies for the SIP. The application of these models is very time and resource intensive. For example, these require detailed information on the spatial distribution of the emissions of various species of pollutants from not only New York sources, but from those in neighboring states in order to properly determine impacts of NO_x and VOC precursor emissions on regional O_3 levels. At present, detailed necessary information for the proper applications of this modeling exercise is lacking. However, as part of its commitment to the EPA, and in cooperation with the Ozone Transport Commission to consider future year emission strategies for the Ozone SIP, the Department would include the emissions from Marcellus Shale operations in subsequent SIP modeling scenarios. As such, properly quantified emissions specifically resulting from Marcellus Shale operations would be included in future SIP inventories to the extent that the information becomes available. Interim to this detailed modeling, the Department would perform a screening level regional modeling exercise by adding the projected emissions associated with New York's portion of the Marcellus Shale drilling to the baseline inventory which is currently being finalized. This modeling would guide the Department's finalization of the SGEIS. In addition to the availability of the regional modeling results, the Department has recommended that a monitoring program be undertaken by industry to address both regional and local air quality concerns as discussed in the next section.

6.5.4 Air Quality Monitoring Requirements for Marcellus Shale Activities

In order to fully address potential for adverse air quality impacts beyond those analyzed in the SGEIS relate to associated activities which are either not fully known at this time or verifiable by the assessments to date, it has been determined that a monitoring program would be undertaken. For example, the consequences of the increased regional NO_x and VOC emissions on the resultant levels of ozone and PM2.5 cannot be fully addressed by only modeling at this stage due to the lack of detail on the distribution of the wells and compressor stations. In addition, any potential emissions of certain VOCs at the well sites due to fugitive emissions, including possible endogenous level, and from the drilling and gas processing equipment at the compressor station (e.g. glycol dehydrators) are not fully quantifiable. Thus, it has been determined that an air monitoring plan is necessary to address these regional concerns as well as to verify the local-scale impact of emissions from the three phases of gas field development: drilling, completion and production. The monitoring plan discussed herein is determined to be the level of effort necessary to assure that the overall activities of the gas drilling in the Marcellus Shale would not cause adverse regional or local air quality impacts. The monitoring is an integral component of the requirements for industry to undertake to satisfy the SEQRA findings of acceptable air quality levels.

Based on the results from the Department's assessments of gas production emissions, and in consideration of the well permitting approach and the modeling analysis, an air monitoring plan has been developed to address the level of effort necessary to determine and distinguish both background and drilling related concentrations of pertinent pollutants. In addition, a review of previous monitoring activities for shale drilling conducted by the TCEQ[104] and the PADEP[105] was undertaken to better characterize the monitoring needs and instrumentation. The approach selected as best suited for monitoring for New York Marcellus Shale activities combines a regional and local scale monitoring effort aimed at different aspects of emission impact characterization. These two efforts are as follows:

1) Regional level monitoring: In order to assess the impact of regional emissions of precursors including VOCs and NO_x, monitoring for O_3 and PM2.5 would need to be conducted at two locations. One would be a "background" site and another would need to be placed at a downwind location sited to reflect the likely impact area from the atmospheric transport and conversion of the precursors into secondary pollutants. These would enhance the current Department O_3 monitoring in the area. These sites would also

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105 See: http://www.dep.state.pa.us/dep/deputate/airwaste/aq/toxics/toxics.htm.

need to be equipped with air toxics monitors so that pollutant levels can be compared to each other and to other existing sites; and

2) Near-field/local scale monitoring at various locations in the Marcellus Shale: This monitoring can be intermittent but would be carried out in areas expected to be directly impacted by one or more wells and compressor stations. The data from this monitoring effort would be used to assess the significance of the various known drilling related activities and to identify specific pollutants that may pose a concern. In addition, possible fugitive emissions of certain VOCs should be monitored to locate and mitigate emissions, beyond those necessary for worker safety purposes. The Department has identified specific well drilling activities and pollutants which have been found to be related to these activities and recommends that these are included in the near-field monitoring program See Table 6.23.

Table 6.23 - Near-Field Pollutants of Concern for Inclusion in the Near-Field Monitoring Program (New July 2011)

Well Pad and Related Activity	**Pollutants of Concern**
Drilling and Completing (completion equipment) Engines	1-Hour NO_2 and 24-hour PM2.5
Gas venting (could be potentially mitigated by REC)	BTEX, formaldehyde, H_2S or another odorant.
Glycol dehydrator and condensate tanks at either the well pad or at the compressor station (if wet gas is present)	BTEX, benzene, and formaldehyde.
Leaks and fugitives	Methane and VOC emissions

The near-field local scale monitoring is expected to be performed periodically with field campaigns typically lasting a few days when activities are occurring at the well pad and when the compressor station is operational and operating near maximum gas flow conditions. Since the scope of gas related emissions from one area of operation to another is limited, it is anticipated that after a few intensive near-field monitoring campaigns, adequate and representative data would be gathered to understand the potential impacts of the various phases of gas drilling and production. At that point, the level of effort and the further need for the short term monitoring would be evaluated. In addition to the near-field monitoring, it is anticipated that a similar level of short term monitoring would be conducted on a limited basis at a nearby residential location or in a representative community setting to determine the actual exposure to the public.

However, based on the results from the TCEQ and PADEP monitoring, the potential for finding relatively higher concentrations would likely be in close proximity to the well pad and compressor station.

It is expected that the cost and implementation of this monitoring would be the responsibility of industry. To carry out this monitoring plan, a specific set of monitoring equipment and procedures would be necessary. Some of these deviate from the "traditional" compliance oriented monitoring plans; for example, due to the relatively short term and intensive monitoring required at various locations of activities, the suggested approach would be to operate a mobile equipped unit. Department monitoring staff has longstanding expertise in conducting this type of monitoring over the last two decades. The most recent local-scale monitoring project carried out by the Department was the Tonawanda Community Air Quality Monitoring project.

As an alternative to industry implementing this monitoring plan in a repetitive company by company stepwise fashion as gas development progresses, it is the Department 's preference that the monitoring be undertaken by the Department's Division of Air Resources monitoring staff. However, this alternative cannot be carried out with current Department staff or equipment and would only be possible with additional staff and equipment resources. This alternative is preferred from a number of standpoints, including:

1) Overall program cost would be reduced because each operator would not be responsible for their own monitoring program. Even if the operators are able to hire a common consultant, there would be complexities in allocation the work to various locations;

2) The Department would not have to "oversee" contractor work hired either by industry or by the Department;

3) The timing and production of data analysis would be simplified and reports would be under the Department's control;

4) The Department can utilize certain existing monitor sites for the regional monitoring program;

5) The central coordination would minimize the overall costs of the monitoring; and

6) The Department would have the ability to monitor near the compressor stations which might not be within the control of the drilling operators.

If the Department was to receive the necessary funding and staff to conduct the monitoring, the following table identifies some of the specifics associated with the expected level of monitoring.

Table 6.24 - Department Air Quality Monitoring Requirements for Marcellus Shale Activities (New July 2011)

Monitoring Parameters	Purpose of Monitoring	Proposed Scheme and Instrumentation Needs.
Regional scale O_3, PM2.5, NO_2 and add toxics.	To assess the impact of regional VOC and NO_x emissions on Ozone and PM2.5 levels.	Add a Department monitoring trailer to a new site in Binghamton, plus add toxics at existing Pinnacle site and the new site.
Local/near field monitoring for BTEX, methane, formaldehyde, sulfur (plus O_3, PM2.5 and NO_2)	To assess impacts close-by to well pads, compressor stations and associated equipment (e.g. glycol dehydrator, condensate tanks). Also, limited follow-up in nearby communities.	Purpose-built vehicle with generators as a mobile laboratory. A less desirable alternative is a "stationary" trailer which would need days for initialization.
Intermittent methane and VOC leaks from sources (e.g. fugitive)	To detect and initiate company mitigation of fugitive leaks.	Forward Looking Infrared (FLIR) cameras- one for routine inspections, second to respond to complaints.
"Saturated" BTEX and other VOC species monitoring	To verify the spatial extent of the mobile monitoring results.	Manually operated canister samplers which can be analyzed for 1 to 24-hour concentrations of various toxics.

This monitoring would be the minimum level of effort necessary to properly characterize the air quality in the affected areas for the pollutants which have been identified as possibly requiring mitigation measures or having an effect due to regional emissions. In developing the monitoring approach, Department staff has reviewed the results of the monitoring conducted by TCEQ and PADEP to learn from their experiences, as well as from our own toxics monitoring experiences. To that end, it was determined that a mobile unit with the necessary equipment which would best perform the monitoring for both near-field and representative community based areas. The use of an open path Fourier-transform Infrared (FTIR) spectroscopy used in the PADEP study was evaluated, but deemed unnecessary due to the fact that the mobile unit would be detecting the same pollutants at lower more health relevant detection levels. To overcome the potential concern with spatial representativeness of the near-field monitoring program, the Department recommends augmenting the mobile vehicle with manually placed canisters which could be used on a limited basis to provide a wider areal coverage during the various activities and as a secondary confirmation of the mobile unit results.

The monitoring plan outlined above would be used to address public concerns with the actual pollutant levels in the areas undergoing drilling activities. In addition, it could assist in the identification of the level of conservatism used in the emission estimates for the well pads, the Marcellus area region, and modeling analysis which have been noted as concerns.

6.5.5 Permitting Approach to the Well Pad and Compressor Station Operations

The discussions in subsection 6.5.1.9 of the regulatory applicability section outline the approach which the Department has determined is in line with regulatory permitting requirements and which best address the issues surrounding the air permitting of the three phases of gas drilling, completion and production. The use of the compressor station air permit application process to determine the regulatory disposition and necessary control measures on a case-by-case basis is in keeping with the approach taken throughout the country, as affirmed by EPA in a number of instances. This review process would allow the proper determination of the applicable regulations to both the compressor station and all associated well operations in defining the facility to which the requirements should apply. In concert with the strict operational restrictions determined in the modeling section necessary for the drilling and completion equipment engines, the self-imposed operational and emission limits put forth by industry would assure compliance with all applicable standards. To further assure that these restrictions are adhered to for all well operations, a set of necessary conditions identified in Section 7.5.3 and Appendix 10 will be included in DMN well permits.

DMN Well Drilling Permit Process Requirements

Based on industry's self-imposed limitations on operations and the Department's determination of conditions necessary to avoid or mitigate adverse air quality impacts from the well drilling, completion and production operations, mitigation noted in Chapter 7 would be imposed in the well permitting process.

6.6 Greenhouse Gas Emissions

On July 15, 2009, the Department's Office of Air, Energy and Climate issued its *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*.[106] The policy reflected in the guide is used by Department staff in reviewing an environmental impact statement (EIS) when the Department is the lead agency under SEQRA and energy use or GHG emissions have been identified as significant in a positive declaration, or as a result of scoping, and, therefore, are required to be discussed in an EIS. Following is an assessment of potential GHG emissions for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high-volume hydraulic fracturing.

SEQRA requires that lead agencies identify and assess adverse environmental impacts, and then mitigate or reduce such impacts to the extent they are found to be significant. Consistent with this requirement, SEQRA can be used to identify and assess climate change impacts, as well as the steps to minimize the emissions of GHGs that cause climate change. Many measures that would minimize emissions of GHGs would also advance other long-established State policy goals, such as energy efficiency and conservation; the use of renewable energy technologies; waste reduction and recycling; and smart and sustainable economic growth. The *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement* is

[106] http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf.

not the only State policy or initiative to promote these goals; instead, it furthers these goals by providing for consideration of energy conservation and GHG emissions within EIS reviews.[107]

The goal of this analysis is to characterize and present an estimate of GHG emissions for the siting, drilling and completion of 1) single vertical well, 2) single horizontal well, 3) four-well pad (i.e., four horizontal wells at the same site), and respective first-year and post first-year emissions of CO_2, and other relative GHGs, as both short tons and as carbon dioxide equivalents (CO_2e) expressed in short tons, for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. In addition, the major contributors of GHGs are to be identified and potential mitigation measures offered.

6.6.1 Greenhouse Gases

The two most abundant gases in the atmosphere, nitrogen (comprising 78% of the dry atmosphere) and oxygen (comprising 21%), exert almost no greenhouse effect. Instead, the greenhouse effect comes from molecules that are more complex and much less common. Water vapor is the most important greenhouse gas, and CO_2 is the second-most important one.[108] Human activities result in emissions of four principal GHGs: CO_2, methane (CH_4), nitrous oxide (N_2O) and the halocarbons (a group of gases containing fluorine, chlorine and bromine). These gases accumulate in the atmosphere, causing concentrations to increase with time. Many human activities contribute GHGs to the atmosphere.[109] Whenever fossil fuel (coal, oil or gas) burns, CO_2 is released to the air. Other processes generate CH_4, N_2O and halocarbons and other GHGs that are less abundant than CO_2, but even better at retaining heat.[110]

6.6.2 Emissions from Oil and Gas Operations

GHG emissions from oil and gas operations are typically categorized into 1) vented emissions, 2) combustion emissions and 3) fugitive emissions. Below is a description of each type of emission. For the noted emission types, no distinction is made between direct and indirect emissions in this analysis. Further, this GHG discussion is focused on CO_2 and CH_4 emissions

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107 http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf.

108 http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf.

109 http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf.

110 http://www.dec.ny.gov/energy/44992.html.

as these are the most prevalent GHGs emitted from oil and gas industry operations, including expected exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. Virtually all companies within the industry would be expected to have emissions of CO_2 - and, to a lesser extent, CH_4 and N_2O - since these gases are produced through combustion. Both CH_4 and CO_2 are also part of the materials processed by the industry as they are produced in varying quantities, from oil and gas wells. Because the quantities of N_2O produced through combustion are quite small compared to the amount of CO_2 produced, CO_2 and CH_4 are the predominant oil and gas industry GHGs.[111]

6.6.2.1 Vented Emissions

Vented sources are defined as releases resulting from normal operations. Vented emissions of CH_4 can result from the venting of natural gas encountered during drilling operations, flow from the flare stack during the initial stage of flowback, pneumatic device vents, dehydrator operation, and compressor start-ups and blowdowns. Oil and natural gas operations are the largest human-made source of CH_4 emissions in the United States and the second largest human-made source of CH_4 emissions globally. Given methane's role as both a potent greenhouse gas and clean energy source, reducing these emissions can have significant environmental and economic benefits. Efforts to reduce CH_4 emissions not only conserve natural gas resources but also generate additional revenues, increase operational efficiency, and make positive contributions to the global environment.[112]

6.6.2.2 Combustion Emissions

Combustion emissions can result from stationary sources (e.g., engines for drilling, hydraulic fracturing and natural gas compression), mobile sources and flares. Carbon dioxide, CH_4, and N_2O are produced and/or emitted as a result of hydrocarbon combustion. Carbon dioxide emissions result from the oxidation of the hydrocarbons during combustion. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, and this conversion is relatively independent of the fuel or firing configuration. Methane emissions may result due to incomplete

[111] IPIECA and API, December 2003, p. 5-2.

[112] http://www.epa.gov/gasstar/documents/ngstar_mktg-factsheet.pdf.

combustion of the fuel gas, which is emitted as unburned CH_4. Overall, CH_4 and N_2O emissions from combustion sources are significantly less than CO_2 emissions.[113]

6.6.2.3 Fugitive Emissions

Fugitive emissions are defined as unintentional gas leaks to the atmosphere and pose several challenges for quantification since they are typically invisible, odorless and not audible, and often go unnoticed. Examples of fugitive emissions include CH_4 leaks from flanges, tube fittings, valve stem packing, open-ended lines, compressor seals, and pressure relief valve seats. Three typical ways to quantify fugitive emissions at a natural gas industry site are 1) facility level emission factors, 2) component level emission factors paired with component counts, and 3) measurement studies.[114] In the context of GHG emissions, fugitive sources within the upstream segment of the oil and gas industry are of concern mainly due to the high concentration of CH_4 in many gaseous streams, as well as the presence of CO_2 in some streams. However, relative to combustion and process emissions, fugitive CH_4 and CO_2 contributions are insignificant.[115]

6.6.3 Emissions Source Characterization

Emissions of CO_2 and CH_4 occur at many stages of the drilling, completion and production phases, and can be dependent upon technologies applied and practices employed. Considerable research – sponsored by the API, the Gas Research Institute (GRI) and the EPA – has been directed towards developing relatively robust emissions estimates at the national level.[116] The analytical techniques and emissions factors, and mitigation measures, developed by the these agencies were used to evaluate GHG emissions from activities necessary for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high-volume hydraulic fracturing.

In 2009, NYSERDA contracted ICF International (ICF) to assist with supporting studies for the development of the SGEIS. ICF's work included preparation of a technical analysis of potential impacts to air in the form of a report finalized in August 2009.[117] The report, which includes a

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[113] API 2004; amended 2005. p 4-1.
[114] ICF Task 2, 2009, p. 21.
[115] IPIECA and API, December 2003., p. 5-6.
[116] New Mexico Climate Change Advisory Group, November 2006, , pp. D-35.
[117] ICF Task 2, 2009.

discussion on GHGs, provided the basis for the following in-depth analysis of potential GHGs from the subject activity. ICF's referenced study identifies drilling, completion and production operations and equipment that contribute to GHG emission and provides corresponding emission rates, and this information facilitated the following analysis by identifying system components on an operational basis. As such, wellsite operations considered in the SGEIS were divided into the following phases for this GHG analysis:

- Drilling Rig Mobilization, Site Preparation and Demobilization;
- Completion Rig Mobilization and Demobilization;
- Well Drilling;
- Well Completion (includes hydraulic fracturing and flowback); and
- Well Production.

Transport of materials and equipment is an integral component of the oil and gas industry. Simply stated, a well cannot be drilled, completed or produced without GHGs being emitted from mobile sources. The estimated required truck trips per well and corresponding fuel usage for the below noted phases requiring transportation, except well production, were provided by industry.[118]

Drilling Rig Mobilization, Site Preparation and Demobilization

Drill Pad and Road Construction Equipment
Drilling Rig
Drilling Fluid and Materials
Drilling Equipment (casing, drill pipe, etc.)

Completion Rig Mobilization and Demobilization

Completion Rig

[118] ALL Consulting, 2011, Exhibits 19B, 20B.

Well Completion

Completion Fluid and Materials
Completion Equipment (pipe, wellhead)
Hydraulic Fracturing Equipment (pump trucks, tanks)
Hydraulic Fracturing Water
Hydraulic Fracturing Sand
Flow Back Water Removal

Well Production[119]

Production Equipment (5 – 10 Truckloads)

Mileage estimates for both light duty and heavy duty trucks were used to determine total fuel usage associated with site preparation and rig mobilizations, well completion and well production activities. As further discussed below, when actual or estimated fuel use data was not available, VMT formed the basis for estimating CO_2 emissions.

Three distinct types of well projects were evaluated for GHG emissions as follows:

- Single-Well Vertical Project;
- Single-Well Horizontal Project; and
- Four -Well Pad (i.e., four horizontal wells at the same site).

For rig and equipment mobilizations for each of the project types noted above, it was assumed that all work involving the same activity would be finished before commencing a different activity. In other words, the site would be prepared and the drilling rig mobilized, then all wells (i.e., one or four) would be drilled, followed by the completion of all wells (i.e., one or four) and subsequent production of all wells (i.e., one or four). A number of operators have indicated to the Department that activities on multi-well pads would be conducted sequentially, whenever possible, to realize the greatest efficiency but the actual order of work events and number of wells on a given pad may vary. Nevertheless, four wells was the number of wells selected for

[119] NTC Consultants. *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, September 2009.

the multi-well pad GHG analysis because industry indicated that number would be the maximum number of wells drilled at the same site in any 12 consecutive months.

Stationary engines and equipment emit CO_2 and/or CH_4 during drilling and completion operations. However, most are not typically operating at their full load every hour of each day while on location. For example, certain engines may be shut down completely or operating at a very low load during bit trips, geophysical logging or the running of casing strings. Consequently, for the purpose of this analysis and as noted in Table 6.25 and Table 6.26 below, it was assumed that engines and equipment for drilling and completion operations generally operate at full load for 50% of their time on location. Exceptions to this included engines and equipment used for hydraulic fracturing and flaring operations. Instead of relying on an assumed time frame for operation for the many engines that drive the high-pressure high-volume pumps used for hydraulic fracturing, an average of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring Pennsylvania and West Virginia was used.[120] In addition, flaring operations and associated equipment were assumed to be operating at 100% for the entire estimated flaring period.

Table 6.25 - Assumed Drilling & Completion Time Frames for Single Vertical Well (New July 2011)

Operation	Estimated Duration (days / hrs.)	Assumed Full Load Operational Duration for Related Equipment (days / hrs.)
Well Drilling	13 / 312	6½ / 156
Completion	¼ / 6 (hydraulic fracturing) 1 / 24 (rig)	¼ / 6 (hydraulic fracturing) ½ / 12 (rig)
Flaring	3 / 72	3 / 72

Table 6.26 - Assumed Drilling & Completion Time Frames for Single Horizontal Well (Updated July 2011)

Operation	Estimated Duration (days / hrs.)	Assumed Full Load Operational Duration for Related Equipment (days / hrs.)
Well Drilling	25 / 600	12½ / 300
Completion	2 / 48 (hydraulic fracturing) 2 / 48 (rig)	2 / 48 (hydraulic fracturing) 1 / 24 (rig)
Flaring	3 / 72	3 / 72

[120] ALL Consulting, 2009, Table 11, p. 10.

Stationary engines and equipment also emit CO_2 and/or CH_4 during production operations. In contrast to drilling and completion operations, production equipment generally operates around the clock (i.e., 8,760 hours per year) except for scheduled or intermittent shutdowns.

6.6.4 Emission Rates

The primary reference for emission rates for stationary production equipment considered in this analysis is the GRI's *Methane Emissions from the Natural Gas Industry*. Table GHG-1 "Emission Rates for Well Pad" in Appendix 19, Part A shows greenhouse gas (GHG) emission rates for associated equipment used during natural gas well production operations. Table GHG-1 was adapted from an analysis of potential impacts to air performed in 2009 by ICF International under contract to NYSERDA. GHG emission rates for flaring during the completion phase were also obtained from the ICF International study. The emission factors in the table are typically listed in units of pounds emitted per hour for each piece of equipment or are based on gas throughput. The emissions rates specified in the table were used to determine the annual emissions in tons for each stationary source, except for engines used for rig and hydraulic fracturing engines, using the below equation. The *Activity Factor* represents the number of pieces of equipment or occurrences.

$$\text{Emissions (tons/yr.)} = \text{Emissions Factor (lbs./hr)} \times \text{Duration (yr.)} \times (8{,}760 \text{ hrs/yr.}) \times (1 \text{ US short ton}/2{,}000 \text{ lbs}) \times \text{Activity Factor}$$

A material balance approach based on fuel usage and fuel carbon analysis, assuming complete combustion (i.e., 100% of the fuel carbon combusts to form CO_2), is the preferred technique for estimating CO_2 emissions from stationary combustion engines.[121] This approach was used for the engines required for conducting drilling and hydraulic fracturing operations. Actual fuel usage, such as the volume of fuel needed to perform hydraulic fracturing, was used where available to determine CO_2 emissions. For emission sources where actual fuel usage data was not available, estimates were made based on the type and use of the engines needed to perform the work. For GHG emission from mobile sources, such as trucks used to transport equipment and materials, where fuel use data was not available VMT was used to estimate fuel usage. The calculated fuel used was then used to determine estimated CO_2 emissions from the mobile

[121] API, 2004; amended 2005., p. 4-3.

sources. A sample calculation showing this methodology for determining combustion emissions (CO_2) from mobile sources is included as Appendix 19, Part B.

Carbon dioxide and CH_4 emissions, the focus of this analysis, are produced from the flaring of natural gas during the well completion phase. Emission rates and calculations from the flaring of natural gas are presented in the previously mentioned 2009 ICF International report. In that report, it was determined that approximately 576 tons of CO_2 and 4.1 tons of CH_4 are emitted each day for a well being flared at a rate of 10 MMcf/d. ICF International's calculations assumed that 2% of the gas by volume goes uncombusted. ICF International relied on an average composition of Marcellus Shale gas to perform its emissions calculations.

6.6.5 Drilling Rig Mobilization, Site Preparation and Demobilization

Transportation combustion sources are the engines that provide motive power for vehicles used as part of wellsite operations. Transportation sources may include vehicles such as cars and trucks used for work-related personnel transport, as well as tanker trucks and flatbed trucks used to haul equipment and supplies. Light-duty and heavy-duty vehicles use is accounted for and differentiated in this analysis.[122] The fossil fuel-fired internal combustion engines used in transportation are a significant source of CO_2 emissions. Small quantities of CH_4 and N_2O are also emitted based on fuel composition, combustion conditions, and post-combustion control technology. Estimating emissions from mobile sources is complex, requiring detailed information on the types of mobile sources, fuel types, vehicle fleet age, maintenance procedures, operating conditions and frequency, emissions controls, and fuel consumption. The EPA has developed a software model, MOBILE Vehicle Emissions Modeling Software, that accounts for these factors in calculating exhaust emissions (CO_2, HC, CO, NO_x, particulate matter, and toxics) for gasoline and diesel fueled vehicles. The preferred approach for estimating CH_4 and N_2O emissions from mobile sources is to assume that these emissions are negligible compared to CO_2.[123]

An alternative to using modeling software for determining CO_2 emissions for general characterization is to estimate GHG emissions using VMT, which includes a determination of

[122] ALL Consulting, 2011, Exhibits 19B, 20B.

[123] API, 2004; amended 2005, pp. 4-32, 4-33.

estimated fuel usage, or use a fuel usage estimate if available. These methodologies were used to calculate the tons of CO_2 emissions from mobile sources related to the subject activity. A sample CO_2 emissions calculation using fuel consumption is shown in Appendix 19, Part B. Table GHG-2 in Appendix 19, Part A includes CO_2 emission estimates for transporting the equipment necessary for constructing the access road and well pad, and moving the drilling rig to and from the well site. For horizontal wells, Table GHG-2 assumes that the same rig stays on location and drills both the vertical and lateral portions of a well.

As previously mentioned, because all activities are assumed to be performed sequentially requiring a single rig move, the GHG emissions presented in Table GHG-2 are representative of either a one-well project or four-well pad. As shown in the table, approximately 15 tons of CO_2 emissions are expected from a mobilization of the drilling rig, including site preparation. Site preparation for a single vertical well would be less due to a smaller pad size but for simplification site preparation is assumed the same for all well scenarios considered. The calculated CO_2 emissions shown in this table and all other tables included in this analysis have been rounded up to the next whole number.

6.6.6 Completion Rig Mobilization and Demobilization

Table GHG-3 in Appendix 19, Part A includes CO_2 emission estimates for transporting the completion rig to and from the wellsite. As shown in the table, approximately 4 tons of CO_2 emissions may be generated from a mobilization of the completion rig. For simplification, tramsportation associated with rig mobilization for the completion rig was assumed to be the same as that for the drilling rig. It is acknowledged that this assumption is conservative.

6.6.7 Well Drilling

Vertical wells may be drilled entirely using compressed air as the drilling fluid or possibly with air for a portion of the well and mud in the target interval. For horizontal wells, drilling activities would typically include the drilling of the vertical and lateral portions of a well using compressed air and mud (or other fluid) respectively. Regardless of the type of well, drilling activities are dependent on the internal combustion engines needed to supply electrical or hydraulic power to: 1) the rotary table or topdrive that turns the drillstring, 2) the drawworks, 3) air compressors, and 4) mud pumps. Carbon dioxide emissions occur from the engines needed to perform the work required to spud the well and reach its total depth. Table GHG-4 in Appendix 19, Part A includes estimates for CO_2 emissions generated by these stationary sources. As shown in the table, approximately 83 tons of CO_2 emissions per single vertical well would be generated as a result of drilling operations. Tables GHG-5 and GHG-6 show CO_2 emissions of 194 tons and 776 tons for the drilling of a single horizontal well and four-well pad, respectively.

6.6.8 Well Completion

Well completion activities include 1) transport of required equipment and materials to and from the site, 2) hydraulic fracturing of the well, 3) a flowback period, including flaring, to clean the well of fracturing fluid and excess sand used as the hydraulic fracturing proppant, 4) drilling out of hydraulic fracturing stage plugs and the running of production tubing by the completion rig and 5) site reclamation. Mobile and stationary engines, and equipment used during the aforementioned completion activities emit CO_2 and/or CH_4. Tables GHG-7, GHG-8 and GHG-9 in Appendix 19, Part A include estimates of individual and total emissions of CO_2 and CH_4 generated during the completion phase for a single vertical well, single horizontal well and a four-well pad, respectively.

Similar to the above discussion regarding mobilization and demobilization of rigs, transport of equipment and materials, which results in CO_2 emissions, is necessary for completion of wells. The results of this evaluation are shown in Tables GHG-7, GHG-8 and GHG-9 of Appendix 19, Part A. GHG emissions of CO_2 from transportation provided in the tables rely on estimated fuel usage for both light and heavy trucks. A sample calculation for determining CO_2 emissions based on fuel usage is shown in Appendix 19, Part B. As shown in Table GHG-7, transportation related completion-phase emissions of CO_2 for a single vertical well is estimated at 12 tons. For the single horizontal well and the four-well pad (see Table GHG-8 and GHG-9), transportation related completion-phase CO_2 emissions are estimated at 31 to 115 tons, respectively.

Hydraulic fracturing operations require the use of many engines needed to drive the high-pressure high-volume pumps used for hydraulic fracturing (see multiple "Pump trucks" in the Photos Section of Chapter 6). As previously discussed and shown in Table GHG-5 in Appendix 19, Part A, an average (i.e., 29,000 gallons of diesel) of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring

Pennsylvania and West Virginia was used to calculate the estimated amount of CO_2 emitted during hydraulic fracturing. Fuel usage for the single vertical well was prorated to account for less time pumping (i.e., one-eighth). Tables GHG-7, GHG-8 and GHG-9 show that approximately 54 tons and 325 tons of CO_2 emissions per well would be generated as a result of single vertical well and single horizontal well hydraulic fracturing operations, respectively.

Subsequent to hydraulic fracturing in which fluids are pumped into the well, the direction of flow is reversed and flowback waters, including reservoir gas, are routed through separation equipment to remove excess sand, then through a line heater and finally through a separator to separate water and gas on route to the flare stack. Generally speaking, flares in the oil and gas industry are used to manage the disposal of hydrocarbons from routine operations, upsets, or emergencies via combustion.[124] However, only controlled combustion events would be flared through stacks used during the completion phase for the Marcellus Shale and other low-permeability gas reservoirs. A flaring period of 3 days was considered for this analysis for the vertical and horizontal wells respectively although the actual period could be either shorter or longer.

Initially, only a small amount of gas recovered from the well is vented for a relatively short period of time. If a sales line is available, once the flow rate of gas is sufficient to sustain combustion in a flare, the gas is flared until there is sufficient flowing pressure to flow the gas into the sales line.[125] Otherwise, the gas is flared and combusted at the flare stack. As shown in Tables GHG-7 and GHG-8 in Appendix 19, Part A, approximately 1,728 tons of CO_2 and 12 tons of CH_4 emissions are generated per well during a three-day flaring operation for a 10 Mmcf/d flowrate. As mentioned above, the actual duration of flaring may be more or less. The CH_4 emissions during flaring result from 2% of the gas flow remaining uncombusted. ICF computed the primary CO_2 and CH_4 emissions rates using an average Marcellus gas composition.[126] The duration of flaring operations may be shortened by using specialized gas recovery equipment, provided a gas sales line is in place at the time of commencing flowback from the well. Recovering the gas to a sales line, instead of flaring it, is called a REC and is

[124] API, 2004; amended 2005. p. 4-27.

[125] ALL Consulting, 2009. p. 14.

[126] ICF Task 2, 2009, p. 28.

further discussed in Chapter 7 as a possible mitigation measure, and in Appendix 25 (REC Executive Summary included by ICF for its work in support of preparation of the SGEIS).

The final work conducted during the completion phase consists of using a completion rig, possibly a coiled-tubing unit, to drill out the hydraulic fracturing stage plugs and run the production tubing in the well. Assuming a fuel consumption rate of 25 gallons per hour and an operating period of 24 hours, the rig engines needed to perform this work emit CO_2 at a rate of approximately 4 tons per single vertical well and 7 tons per single horizontal well. No stage plug milling is normally required and less tubing is run for a single vertical well as compared to a horizontal well, and less completion time results in less GHG emissions. After the completion rig is removed from the site, earth moving equipment would be transported to the site and the area would be reworked and graded, which adds another 9 tons of CO_2 emissions for either a one-well project or four-well pad. Tables GHG-7, GHG-8 and GHG-9 in Appendix 19, Part A show CO_2 emissions from these final stages of work during the well completion phase for a single vertical well, single horizontal well and a four-well pad, respectively. Site work for a single vertical well would be less due to a smaller pad size but for simplification, site work is assumed the same for all well scenarios considered.

6.6.9 Well Production

GHGs from the well production phase include emissions from transporting the production equipment to the site and then operating the equipment necessary to process and flow the natural gas from the well into the sales line. Carbon dioxide emissions are generated from the trucks needed to haul the production equipment to the wellsite. As previously stated, GHG emissions of CO_2 from transportation rely on estimated fuel usage where available or VMT, which ultimately requires a determination of fuel usage. Such emissions associated with well production activities, include those from transportation related to the removal of production brine, as discussed below. The estimated VMT for each case was then used to determine approximate fuel use and resultant CO_2 emissions. As shown in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A, transportation needed to haul production equipment to a wellsite for a one-well project and a four-well pad results in first-year CO_2emissions of approximately 3 tons and 11 tons, respectively.

Well production may require the removal of production brine from the site which, if present, is stored temporarily in plastic, fiberglass or steel brine production tanks, and then transported off-site for proper disposal or reuse. The trucks used to haul the production brine off-site generate CO_2 emissions. Transportation estimates were used to determine CO_2 emissions from each well development scenario, and emission estimates are presented in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A. Table GHG-10 presents CO_2 and CH_4 emissions for a one-well project for the period of production remaining in the first year after the single vertical well is drilled and completed. For the purpose of this analysis, the duration of production for a single vertical well in its first year was estimated at 349 days (i.e., 365 days minus 16 days to drill & complete) and for a single horizontal well in its first year 331 days (i.e., 365 days minus 34 days to drill & complete). Table GHG-13 shows estimated annual emissions for a single vertical well or single horizontal well commencing in year two, and producing for a full year. Table GHG-12 presents CO_2 and CH_4 emissions for a four-well pad for the period of production remaining in the first year after all ten wells are drilled and completed. For the purpose of this analysis, the duration of production for the ten-well pad in its first year was estimated at 229 days (i.e., 365 days minus 136 days to drill & complete). Instead of work phases occurring sequentially, actual operations may include concurrent well drilling and producing activities on the same well pad. Table GHG-14 shows estimated annual emissions for a four-well project commencing in year two, and producing for a full year.

GHGs in the form of CO_2 and CH_4 are emitted during the well production phase from process equipment and compressor engines. Glycol dehydrators, specifically their vents, which are used to remove moisture from the natural gas in order to meet pipeline specifications and dehydrator pumps, generate vented CH_4 emissions, as do pneumatic device vents which operate by using gas pressure. Compressors used to increase the pressure of the natural gas so that the gas can be put into the sales line typically are driven by engines which combust natural gas. The compressor engine's internal combustion cycle results in CO_2 emissions while compression of the natural gas generates CH_4 fugitive emissions from leaking packing systems. All packing systems leak under normal conditions, the amount of which depends on cylinder pressure, fitting and alignment of the packing parts, and the amount of wear on the rings and rod shaft.[127] The emission rates

[127] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

presented in Table GHG-1, Appendix 19, Part A "Emission Rates for Well Pad" were used to calculate estimated emissions of CO_2 and CH_4 for each stationary source for a single vertical well, single horizontal well and four-well pad using the equation noted in Section 6.6.4 and the corresponding Activity Factors shown in Tables GHG-10, GHG-11, GHG-12, GHG-13 and GHG-14 in Appendix 19, Part A. Based on the specified emissions rates for each piece of production equipment, the calculated annual GHG emissions presented in the Tables show that the compressors, glycol dehydrator pumps and vents contribute the greatest amount of CH_4 emissions during the this phase, while operation of pneumatic device vents also generates vented CH_4 emissions. The amount of CH_4 vented in the compressor exhaust was not quantified in this analysis but, according to Volume II: Compressor Driver Exhaust, of the 1996 Final Report on Methane Emissions from the Natural Gas Industry, compressor exhaust accounts for "about 7.9% of methane emissions from the natural gas industry."

6.6.10 Summary of GHG Emissions

As previously discussed, wellsite operations were divided into the following five phases to facilitate GHG analysis: 1) Drilling Rig Mobilization, Site Preparation and Demobilization, 2) Completion Rig Mobilization and Demobilization, 3) Well Drilling, 4) Well Completion (includes hydraulic fracturing and flowback) and 5) Well Production. Each of these phases was analyzed for potential GHG emissions, with a focus on CO_2 and CH_4 emissions. The results of these phase-specific analyses for a single vertical well, single horizontal well and four-well pad are detailed in Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part A. In addition, the tables include estimates of GHG emissions occurring in the first year and each producing year thereafter for each project type.

The goal of this review is to characterize and present an estimate of total annual emissions of CO_2, and other relative GHGs, as both short tons and CO_2e expressed in short tons for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. To determine CO_2e, each greenhouse gas has been assigned a number or factor that reflects its global warming potential (GWP). The GWP is a measure of a compound's ability to trap heat over a certain lifetime in the atmosphere, relative to the effects of the same mass of CO_2 released over the same time period. Emissions expressed in equivalent terms highlight the contribution of the various gases to the overall inventory.

Therefore, GWP is a useful statistical weighting tool for comparing the heat trapping potential of various gases.[128] For example, Chesapeake Energy Corporation's July 2009 Fact Sheet on greenhouse gas emissions states that CO_2 has a GWP of 1 and CH_4 has a GWP of 23, and that this comparison allows emissions of greenhouse gases to be estimated and reported on an equal basis as CO_2e.[129] However, GWP factors are continually being updated, and for the purpose of this analysis as required by the Department's 2009 *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*, the 100-Year GWP factors provided in below Table 6.27 were used to determine total GHGs as CO_2e. Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part A include a summary of estimated CO_2 and CH_4 emissions from the various operational phases as both short tons and as CO_2e expressed in short tons.

Table 6.27 - Global Warming Potential for Given Time Horizon[130]

Common Name	Chemical Formula	20-Year GWP	100-Year GWP	500-Year GWP
Carbon dioxide	CO_2	1	1	1
Methane	CH_4	72	25	7.6

Table 6.28 is a summary of total estimated CO_2 and CH_4 emissions for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing, as both short tons and as CO_2e expressed in short tons. The below table includes emission estimates for the first full year in which drilling is commenced and subsequent producing years for each project type (i.e., single vertical well, single horizontal well and four-well pad), sourcing of equipment and materials.

The noted CH_4 emissions occurring during the production process and compression cycle represent ongoing annual GHG emissions. As noted above, for the purpose of assessing GHG impacts, each ton of CH_4 emitted is equivalent to 25 tons of CO_2. Thus, because of its recurring nature, the importance of limiting CH_4 emissions throughout the production phase cannot be overstated.

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128 API, August 2009. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

129 Chesapeake Energy Corp., July 2009. *Greenhouse Gas Emissions and Reductions* Fact Sheet.

130 Adapted from Forster, et al. 2007, Table 2.14. Chapter 2, p. 212. http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf.

Table 6.28 - Summary of Estimated Greenhouse Gas Emissions (Revised July 2011)

	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[131]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Estimated First-Year Green House Gas Emissions from Single Vertical Well	8,660	246	6,150	14,810
Estimated First-Year Green House Gas Emissions from Single Horizontal Well	8,761	240	6,000	14,761
Estimated First-Year Green House Gas Emissions from Four-Well Pad	13,901	402	10,050	23,951
Estimated Post First-Year Annual Green House Gas Emissions from Single Vertical or Single Horizontal Well	6,164	244	6,100	12,264
Estimated Post First-Year Annual Green House Gas Emissions from Four-Well Project	6,183	565	14,125	20,300

[131] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Some uncertainties remain with respect to quantifying GHG emissions for the subject activity. For the potential associated GHG emission sources, there are multiple options for determining the emissions, often with different accuracies. Table 6.29, which was prepared by the API, illustrates the range of available options for estimating GHG emissions and associated considerations. The two types of approaches used in this analysis were the "Published emission factors" and "Engineering calculations" options. These approaches, as performed, rely heavily on a generic set of assumptions with respect to duration and sequencing of activities, and size, number and type of equipment for operations that would be conducted by many different companies under varying conditions. Uncertainties associated with GHG emission determinations can be the result of three main processes noted below.[132]

- Incomplete, unclear or faulty definitions of emission sources;
- Natural variability of the process that produces the emissions; and
- Models, or equations, used to quantify emissions for the process or quantity under consideration.

Nevertheless, while the results of potential GHG emissions presented in above Table 6.15 may not be precise for each and every well drilled, the real benefit of the emission estimates comes from the identification of likely major sources of CO_2 and CH_4 emissions relative to the activities associated with gas exploration and development. It is through this identification and understanding of key contributors of GHGs that possible mitigation measures and future efforts can be focused in New York. Following, in Chapter 7, is a discussion of possible mitigation measures geared toward reducing GHGs that would be required, with emphasis on CH_4.

[132] API, August 2009, p. 3-30. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

Table 6.29 - Emission Estimation Approaches – General Considerations[133]

Types of Approaches	General Considerations
Published emission factors	· Accounts for average operations or conditions · Simple to apply · Requires understanding and proper application of measurement units and underlying standard conditions · Accuracy depends on the representativeness of the factor relative to the actual emission source · Accuracy can vary by GHG constituents (i.e., CO_2, CH_4, and N_2O)
Equipment manufacturer emission factors	· Tailored to equipment-specific parameters · Accuracy depends on the representativeness of testing conditions relative to actual operating practices and conditions · Accuracy depends on adhering to manufacturers inspection, maintenance and calibration procedures · Accuracy depends on adjustment to actual fuel composition used on-site · Addition of after-market equipment/controls will alter manufacturer emission factors
Engineering calculations	· Accuracy depends on simplifying assumptions that may be contained within the calculation methods · May require detailed data
Process simulation or other computer modeling	· Accuracy depends on simplifying assumptions that may be contained within the computer model methods · May require detailed input data to properly characterize process conditions · May not be representative of emissions that are due to operations outside the range of simulated conditions
Monitoring over a range of conditions and deriving emission factors	· Accuracy depends on representativeness of operating and ambient conditions monitored relative to actual emission sources · Care should be taken when correcting to represent the applicable standard conditions · Equipment, operating, and maintenance costs must be considered for monitoring equipment
Periodic or continuous[a] monitoring of emissions or parameters[b] for calculating emissions	· Accounts for operational and source specific conditions · Can provide high reliability if monitoring frequency is compatible with the temporal variation of the activity parameters · Instrumentation not available for all GHGs or applicable to all sources · Equipment, operating, and maintenance costs must be considered for monitoring equipment
Footnotes and Sources: [a] Continuous emissions monitoring applies broadly to most types of air emissions, but may not be directly applicable nor highly reliable for GHG emissions. [b] Parameter monitoring may be conducted in lieu of emissions monitoring to indicate whether a source is operating properly. Examples of parameters that may be monitored include temperature, pressure and load.	

[133] API August 2009, p. 3-9, http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

6.7 Naturally Occurring Radioactive Materials in the Marcellus Shale

Chapter 4 explains that the Marcellus Shale is known to contain NORM concentrations at higher levels than surrounding rock formations, and Chapter 5 provides some sample data from Marcellus Shale cuttings. Activities that have the potential to concentrate these constituents through surface handling and disposal may need regulatory oversight to ensure adequate protection of workers, the general public, and the environment. Gas wells can bring NORM to the surface in the cuttings, flowback fluid and production brine, and NORM can accumulate in pipes and tanks (pipe scale and sludge.) Based upon currently available information it is anticipated that flowback water will not contain levels of NORM of significance, whereas production brine is known to contain elevated NORM levels. Radium-226 is the primary radionuclide of concern from the Marcellus.

Elevated levels of NORM in production brine (measured in picocuries/liter or pCi/L) may result in the buildup of pipe scale containing elevated levels of radium (measured in pCi/g). The amount and concentration of radium in the pipe scale would depend on many conditions, including pressures and temperatures of operation, amount of available radium in the formation, chemical properties, etc. Because the concentration of radium in the pipe scale cannot be measured without removing or disconnecting the pipe, a surrogate method is employed, conducting a radiation survey of the pipe exterior. A high concentration of radium in the scale would result in an elevated radiation exposure level at the pipe's exterior surface (measured in mR/hr) and can be detected with a commonly used survey instrument. The Department of Health would require a radioactive materials license when the radiation exposure levels of accessible piping and equipment are greater than 50 microR/hr (μR/hr). Equipment that exhibits dose rates in excess of this level will be considered to contain processed and concentrated NORM for the purpose of waste determinations.

Oil and gas NORM occurs in both liquid (production brine), solid (pipe scale, cuttings, tank and pit sludges), and gaseous states (produced gas). Although the highest concentrations of NORM are in production brine, it does not present a risk to workers because the external radiation levels are very low. However, the build-up of NORM in pipes and equipment (pipe scale and sludge) has the potential to expose workers handling (cleaning or maintenance) the pipe to increased radiation levels. Also wastes from the treatment of production brines may contain concentrated

NORM and therefore may require controls to limit radiation exposure to workers handling this material as well as to ensure that this material is disposed of in accordance with 6 NYCRR § 380.4.

Radium is the most significant radionuclide contributing to oil and gas NORM. It is fairly soluble in saline water and has a long radioactive half life - about 1,600 years (Table 6.30). Radon gas, which under most circumstances is the main human health concern from NORM, is produced by the decay of radium-226, which occurs in the uranium-238 decay chain. Uranium and thorium, which are naturally occurring parent materials for radium, are contained in mineral phases in the reservoir rock cuttings, but have very low solubility. The very low concentrations and poor water solubility are such that uranium and thorium pose little potential health threat.

Table 6.30 - Radionuclide Half-Lives

Radionuclide	**Half-life**	**Mode of Decay**
Ra-226	1,600 years	alpha
Rn-222	3.824 days	alpha
Pb-210	22.30 years	beta
Po-210	138.40 days	alpha
Ra-228	5.75 years	beta
Th-228	1.92 years	alpha
Ra-224	3.66 days	alpha

In addition to exploration and production (E&P) worker protection from NORM exposure, the disposal of NORM-contaminated E&P wastes is a major component of the oil and gas NORM issue. This has attracted considerable attention because of the large volumes of production brine (>109 billion bbl/yr; API estimate) and the high costs and regulatory burden of the main disposal options, which are underground injection in Class II UIC wells and offsite treatment. The Environmental Sciences Division of Argonne National Laboratory has addressed E&P NORM disposal options in detail and maintains a Drilling Waste Management Information System website that links to regulatory agencies in all oil and gas producing states, as well as providing detailed technical information.

In NYS the disposal of processed and concentrated NORM in the form of pipe scale or water treatment waste is subject to regulation under Part 380. Because disposal of Part 380 regulated waste is prohibited in Part 360 regulated solid waste landfills, this waste would require disposal in out-of-state facilities approved to accept NORM wastes. Disposal facilities that can accept this type of waste include select RCRA C facilities and low-level radioactive waste disposal sites.

6.8 Socioeconomic Impacts[134]

This section provides a discussion of the potential socioeconomic impacts on the Economy, Employment, and Income (Section 6.8.1); Population (Section 6.8.2); Housing (Section 6.8.3); Government Revenues and Expenditures (Section 6.8.4); and Environmental Justice (Section 6.8.5). A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this SGEIS.

To estimate the socioeconomic impacts associated with the use of high-volume hydraulic fracturing techniques for extracting natural gas, several assumptions must be made about the amount of natural gas development that would occur, the expected rate of development, the length of time over which that development would occur, and the distribution of this development throughout the state.

For the purposes of this SGEIS, the expected rate of development is measured by the number of wells constructed annually. Two different levels of development are analyzed – a low development scenario, and an average development scenario. These development scenarios were developed by the Department based on information the Department had requested from the Independent Oil & Gas Association of New York (IOGA-NY). IOGA-NY started with an estimated average rate of development based on the following assumptions:

[134] Section 6.8, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

- Approximately 67% of the area covered by the Marcellus and Utica shale is developable;
- Approximately 90% of wells would be horizontal wells, with an average of 160 acres/well; and
- Approximately 10% of wells would be vertical wells, with an average of 40 acres/well.

For the low rate of development, DEC assumed a rate of 25% of IOGA-NY's estimated average rate of development.

Table 6.31 provides a highlight of the major assumptions for each of these scenarios. In both scenarios, the maximum build-out of new wells is assumed to be completed in Year 30. Under the low development scenario, a total of 9,461 horizontal wells and 1,071 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). Under the average development scenario a total of 37,842 horizontal wells and 4,284 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). The high development scenario, which is analyzed in the Economic Assessment Report, assumes a total of 56,508 horizontal and 6,273 vertical wells are constructed at maximum build-out (e.g., Year 30).

Analysis of the high development scenario is not included in this socioeconomic section of the SGEIS in order to be conservative in assessing the positive potential economic benefits of high-volume hydraulic fracturing in New York State. The high development scenario was used as the conservative assumption of activity for all other sections of this SGEIS.

Economic realities, including diminishing marginal returns associated with drilling wells further from the fairway in less than ideal locations, and the exclusion of high-volume hydraulic fracturing wells from certain sensitive locations, would make it highly unlikely that the maximum build-out under the high development scenario would occur. Therefore, only the low and average development scenarios are discussed throughout this section.

These development scenarios are designed to provide order-of-magnitude estimates for the following socioeconomic analysis and are in no way meant to forecast actual well development levels in the Marcellus and Utica Shale reserves in New York State. These scenarios should be viewed as a "best estimate" of the range of possible amounts of development that could occur in New York State.

Table 6.31 - Major Development Scenario Assumptions (New August 2011)

	Scenarios	
	Low	**Average**
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	9,461	37,842
Vertical	1,071	4,284
Total	**10,532**	**42,126**
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	371	1,484
Vertical	42	168
Total	**413**	**1,652**

Both development scenarios assume a consistent timeline for development and production. Development is assumed to occur for a period of 30 years, starting with a 10-year "ramp-up" period. The number of new wells constructed each year is assumed to reach the maximum in Year 10 and to continue at this level until Year 30, when all new well construction is assumed to end. This assumption, which does not significantly affect the socioeconomic impact analysis, was used to remain consistent with other sections of the SGEIS. In actuality, well development would more likely gradually ramp up, reach a peak, and then gradually ramp down as fewer and fewer wells were completed. However, this curve would not necessarily be smooth.

It is unlikely that new well construction would occur under a steady, constant rate. Economic factors such as the price of natural gas, input costs, the price of other energy sources, changes in technology, and the general economic conditions of the state and nation would all affect the yearly rate of well construction and the overall level of development of the gas reserves. The actual track of well construction would likely be much more cyclical in nature than as described in the following sections.

The average development scenario should be viewed as the upper boundary of possible development, while the low development scenario should be viewed as the likely lower boundary of possible development. As shown in Table 6.31, the maximum number of new wells developed in a year under the low development scenario is 371 horizontal and 42 vertical wells, and the maximum number of new wells developed in a year under the average development scenario is 1,484 horizontal and 168 vertical wells.

Each newly constructed well is assumed to have an average productive life of 30 years. For example, wells constructed in Year 1 are assumed to still be producing in Year 30, and wells constructed in Year 10 are assumed to produce until Year 40. Because of the assumption of a 30-year development period, wells constructed in Year 30 are assumed to be productive until Year 60. Assuming a 30-year development period and a 30-year production life for each well, the number of productive wells in New York State would be expected to grow until Year 30, at which point, the number of productive wells would peak. After Year 30, with no new wells being constructed, the number of wells in production would begin to decline. Because the number of annual wells approved and developed each year is different for the two development scenarios, the peak number of operating wells at Year 30 also differs for each scenario.

Under both development scenarios, natural gas production in New York State would occur from Year 1 until Year 60, with Year 30 having the maximum number of wells in production. After Year 30, producing wells would gradually decline until Year 60, at which time it is assumed that production stops.

As discussed in Section 2.4.13, no site-specific project locations are being evaluated in the SGEIS. Therefore, for purposes of analysis, three distinct regions were identified within the area where potential drilling may occur in order to take a closer look at the potential impacts at the regional and local levels. The three regions were selected to evaluate differences between areas with a high, moderate, and low production potential; areas that have experienced gas development in the past and areas that have not experienced gas development in the past; and differences in land use patterns. The three representative regions and the respective counties within the region are:

- Region A: Broome County, Chemung County, and Tioga County;
- Region B: Delaware County, Otsego County; and Sullivan County; and
- Region C: Cattaraugus County and Chautauqua County

This analysis is not intended to imply that impacts would occur only in these three regions. Impacts would occur at the local and regional levels wherever high-volume hydraulic fracturing wells are constructed. The actual locations of these wells have not yet been determined, and they could be constructed wherever there is low-permeable shale. Similar to the development scenarios described above, the representative regions are designed to give a range of possible socioeconomic impacts. Therefore, the results of the local and regional analysis should also be seen as order-of-magnitude estimates for the range of possible impacts. Further descriptions of the regions are provided in Section 2.4.11.

6.8.1 Economy, Employment, and Income

The following discusses the potential impacts on the economy, employment and income for New York State, and the local areas within each of the three regions (Regions A, B and C).

6.8.1.1 New York State

Economy and Employment

Development of low-permeability natural gas reservoirs in the Marcellus and Utica shale by high-volume hydraulic fracturing would be expected to have a significant, positive impact on the economy of New York State. Construction and operation of the new natural gas wells are expected to increase employment, earnings, and economic output throughout the state. According to statistics collected and calculations made by the Marcellus Shale Education and Training Center (the Center), in Pennsylvania, an average natural gas well using the high-volume hydraulic fracturing technique requires 410 individuals working in 150 different occupations. The manpower requirements to drill a single well were calculated to be 11.53 full-time equivalent (FTE) construction workers (Marcellus Shale Education and Training Center 2009).

A full-time equivalent worker is defined as one worker working eight hours a day for 260 days a year, or several workers working a total of 2,080 hours in a year. While the Center found that up to 410 individuals are required to build one well, only 11.53 FTE workers were needed. Typically, a high-volume hydraulic fracturing well is constructed over a 3- to 4-month period, and many of the individuals and occupations are needed for only a very short duration. Therefore, to accurately assess the economic impacts of constructing a high-volume hydraulic fracturing well, the FTE workforce was considered.

The Center also calculated the work force requirements for operating a well as 0.17 FTE workers, or approximately 354 person hours per year. In other words, approximately 1 FTE worker is required to operate and maintain every 6 wells in production (Marcellus Shale Employment and Training Center 2009). Unlike the construction workforce that drills the well within a few months and is finished, the operational workforce is required for the productive life of the well. For the purposes of this analysis, a 30-year productive life has been assumed for each well drilled. Therefore, for every new well drilled, 0.17 FTE workers are employed for 30 years.

In its study, the Marcellus Shale Employment and Training Center did not differentiate between the labor requirements needed to drill a horizontal versus a vertical well. Typically, it is much more costly and labor-intensive to drill a high-volume hydraulic fracturing horizontal well than it is to drill a high-volume hydraulic fracturing vertical well. Therefore, in an effort to be conservative and not overstate the positive economic impacts, a factor was applied to the 11.53 FTE figure for vertical wells in the estimates used for this analysis. This factor was calculated using the average depth of a vertical well compared to the average depth of a high-volume hydraulic-fracturing horizontal well. The resulting ratio of 0.2777 was applied to the 11.53 FTE labor requirement to estimate the overall labor requirements of a vertical well.

Using the workforce requirement figures developed by the Marcellus Shale Employment and Training Center and the two development scenarios described above, the expected impacts on employment and earnings from high-volume hydraulic fracturing were projected for New York State as a whole.

As shown in Table 6.32, annual direct construction employment is directly related to the number of wells drilled in a given year. At the maximum well construction rate assumed for each development scenario, total annual direct construction employment is predicted to range from 4,408 FTE workers under the low development scenario to 17,634 FTE workers under the average development scenario. These employment figures correspond to the annual construction of 413 horizontal and vertical wells under the low development scenario and 1,652 horizontal and vertical wells under the average development scenario. In order to reach the full build-out potential used in the scenarios, it is assumed that construction employment and new well construction would remain at these levels for 20 years, starting in Year 10 (see Table 6.32).

The maximum direct production employment under each development scenario is also shown in Table 6.32. These figures represent the peak production year (Year 30), when the maximum build-out potential has been reached before any of the wells have stopped producing. The preceding and the following years all would have fewer production workers. At the peak, production employment would be expected to range from 1,790 FTE workers under the low development scenario to 7,161 FTE workers under the average development scenario (Table 6.32).

Table 6.32 - Maximum Direct and Indirect Employment Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Direct Employment Impacts		
Construction Employment[1]	4,408	17,634
Production Employment[2]	1,790	7,161
Indirect Employment [3]	7,293	29,174
Total Employment Impacts	13,491	53,969
Total Employment as a Percent of New York State 2010 Labor Force	0.2%	0.7%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

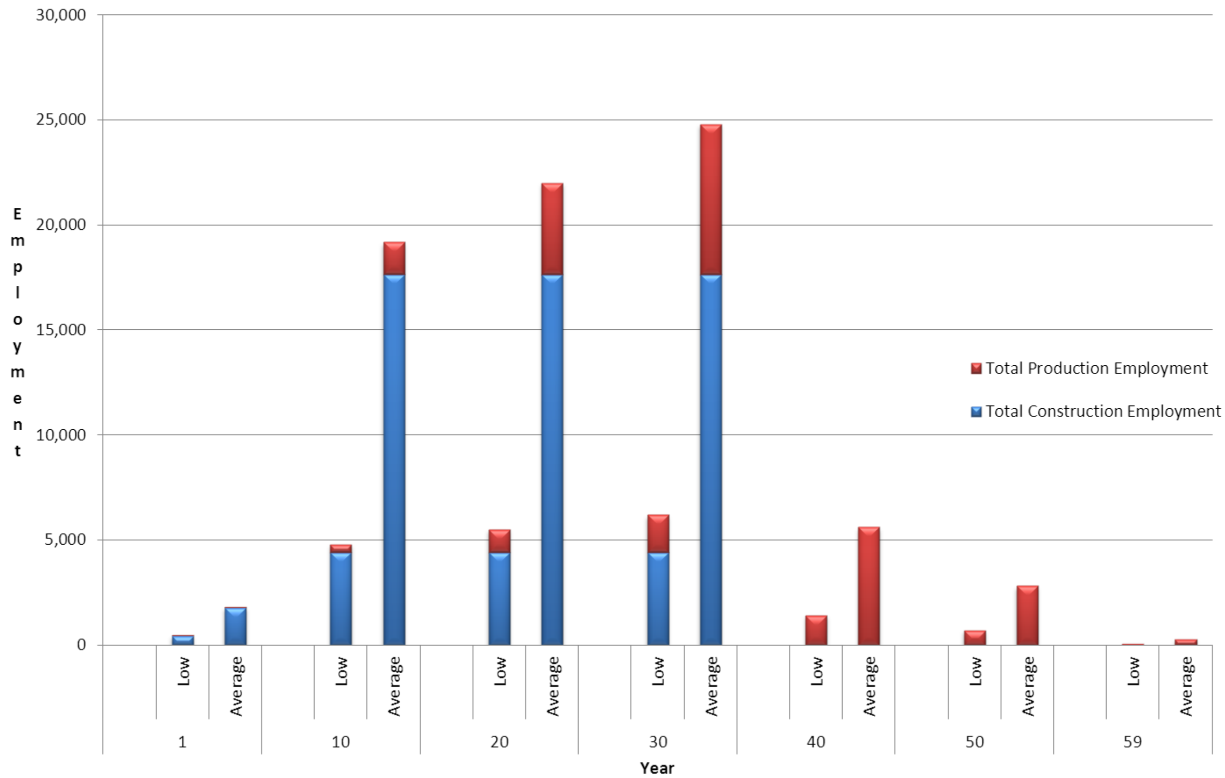
1 These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

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

3 Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

Figure 6.12 illustrates the projected direct employment in New York State that would result from implementation of each development scenario over the 60-year time frame. The figure shows how construction and production employment levels are expected to vary, with peak direct employment occurring in Year 30.

Figure 6.12 – Projected Direct Employment in New York State Resulting from Each Development Scenario (New August 2011)

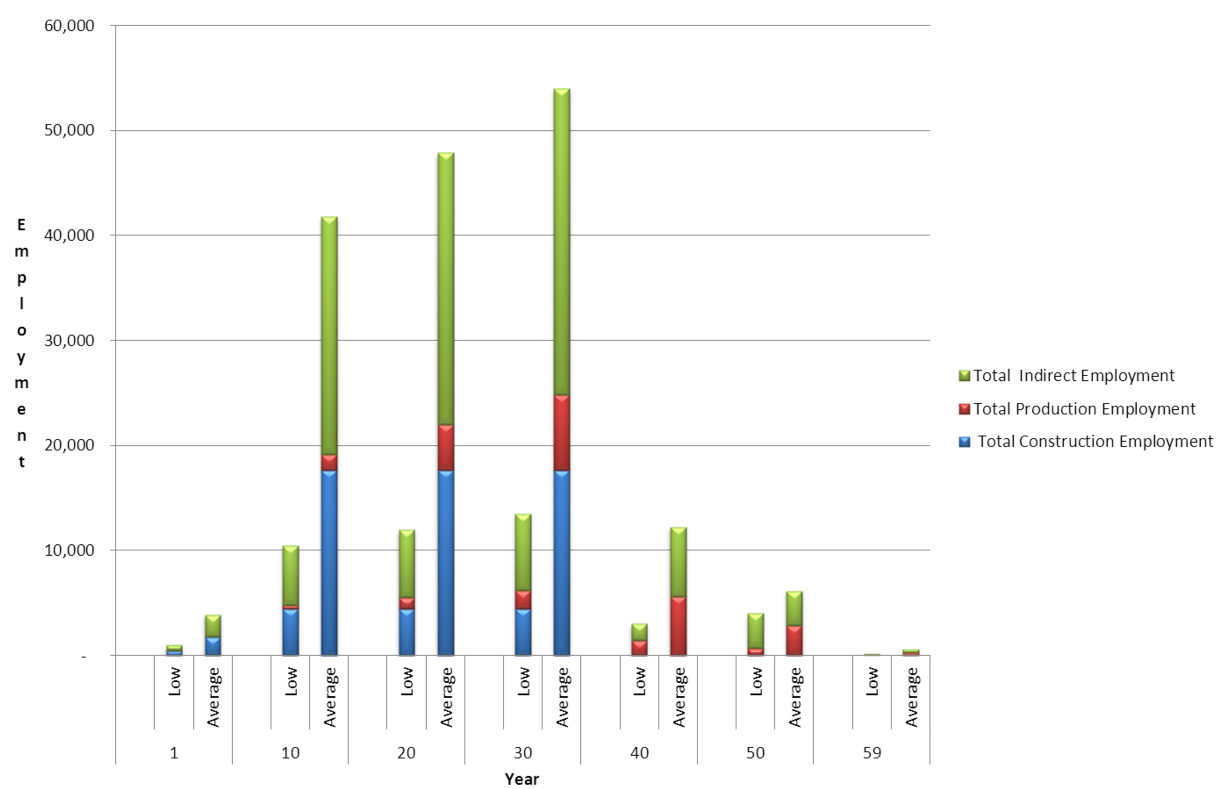


In addition to the direct employment impacts described above, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from suppliers in New York State, the overall demand for goods and services in the state would expand. Revenues at the wholesale and retail outlets and service providers within the state would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the state, thus "multiplying" the positive economic impacts of the original increase in construction/production spending. These "multiplier" effects would continue on until all of the original funds have left New York State's economy through either taxes or savings, or through purchases from outside the state.

Indirect employment impacts are expected to range from an additional 7,293 FTE workers under the low development scenario to an additional 29,174 FTE workers under the average development scenario. These annual figures represent the year with the maximum employment (Year 30). The years before and after this date would have less direct and indirect employment.

In total, at peak employment years, state approval of drilling in the Marcellus and Utica Shales is expected to generate between 13,491 and 53,969 direct and indirect jobs, which equates to 0.2% and 0.6%%, respectively, of New York State's 2010 total labor force, depending on the level and intensity of development that occurs (see Table 6.32). Figure 6.13 graphically illustrates the projected total employment in New York State that would result from each development scenario. As shown on the figure, total employment levels would be highest in Year 10 through Year 30. Once new well construction ends in Year 31, the direct and indirect employment would be greatly reduced.

Figure 6.13 - Projected Total Employment in New York State Resulting from Each Development Scenario (New August 2011)



The majority of these indirect jobs would be concentrated in the construction, professional, scientific, and technical services; real estate and rental/leasing; administrative and waste management services; management of companies and enterprises; and manufacturing industries.

Income

The increase in direct and indirect employment would have a positive impact on income levels in New York State. Table 6.33 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 through Year 30), total annual construction earnings are projected to range from $298.4 million under the low development scenario to nearly $1.2 billion under the average development scenario. Employee earnings from operational employment are expected to range from $121.2 million under the low development scenario to $484.8 million under the average development scenario in Year 30, the year that the maximum number of operational workers are assumed to be employed.

Table 6.33 - Maximum Direct and Indirect Annual Employee Earnings Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Direct Earnings Impacts		
Construction Earnings[1]	$298.4	$1,193.8
Production Earnings[2]	$121.2	$484.8
Indirect Employee Earnings Impacts[2,3]	$202.3	$809.2
Total Employee Earnings Impacts	$621.9	$2,487.8
Total Employee Earnings as a Percent of New York State's 2009 Total Wages	0.1%	0.5%

Source: U.S. Bureau of Economic Analysis 2011a; NYDOL 2009.

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

2 These figures represent the maximum annual production earnings and indirect employee earnings under each development scenario. These figures correspond to operations earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation earnings for all other years.

3 Type I direct earnings multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

As described above, the construction and production activities would also generate significant indirect economic impacts. Indirect employee earnings are anticipated to range from $202.3 million under the low development scenario to $809.2 million under the average development scenario in Year 30. The total direct and indirect impacts on employee earnings are projected to range from $621.9 million to $2.5 billion per year at peak production and construction levels in Year 30. These figures equate to increases of between 0.1% and 0.5% of the total wages and salaries earned in New York State during 2009 (see Table 6.33).

Owners of the subsurface mineral rights where wells are drilled will also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or more of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas production is at its peak, can result in significant increases in income. Signing bonuses/bonus bids also can provide significant additional income to property owners.

6.8.1.2 Representative Regions

As noted above, three representative regions were selected to show the range of possible socioeconomic impacts that could occur at the local and regional levels. This analysis in no way is meant to imply that impacts will occur only in these three regions.

For purposes of this analysis, it is assumed that 50% of all new well construction would occur in Region A (Chemung, Tioga, and Broome counties); 23% would occur in Region B (Otsego, Delaware, and Sullivan counties); 5% would occur in Region C (Chautauqua and Cattaraugus counties); and the remaining 22% of new well construction would occur in the rest of New York State. Geological data on the extent and thickness of the low-permeability shale in New York State, including the Marcellus Shale and Utica Shale fairways, were the basis for these assumptions.

Table 6.34 details the major assumptions for each development scenario for each representative region. In all cases, total development is assumed to be reached at Year 30. As shown in the table, Region A is anticipated to receive the majority of the new well construction. The analysis of Region A is designed to show the upper bound of potential regional economic impacts. Under the low development scenario, a total of 5,281 new wells would be constructed in the counties of Tioga, Chemung, and Broome. Under the average development scenario, a total of 21,067 new wells would be constructed in Region A. The projected maximum number of new wells developed per year in Region A would range from 207 to 826 wells, depending on the development scenario considered. The projected maximum number of new wells developed per year in Region B would range from 2,425 to 9,690 wells, depending on the development scenario (see Table 6.34).

In contrast, Region C is assumed to experience a much smaller level of well development than Region A or Region B. The analysis of Region C is designed to show the lower bound of potential regional economic impacts. Under the low development scenario, a total of 534 new wells would be constructed in Region C. Under the average development scenario, a total of 2,095 new wells would be constructed in Region C. The maximum number of new wells constructed each year in Region C is assumed to be 21 wells under the low development scenario and 82 wells under the average development scenario. The remaining 22% of the development would occur in the rest of the state (see Table 6.34).

Table 6.34 - Major Development Scenario Assumptions for Each Representative Region (New August 2011)

	Scenarios	
	Low	**Average**
Region A		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	4,743	18,923
Vertical	538	2,144
Total	5,281	21,067
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	186	742
Vertical	21	84
Total	207	826
Region B		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,170	8,697
Vertical	255	993
Total	2,425	9,690
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	85	341
Vertical	10	39

	Scenarios	
	Low	**Average**
Total	95	380
Region C		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	483	1,888
Vertical	51	207
Total	534	2,095
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	19	74
Vertical	2	8
Total	21	82
Rest of State		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,065	8,334
Vertical	227	940
Total	2,292	9,274
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	81	327
Vertical	9	37
Total	90	364

Economy and Employment

The proposed approval of the use of high-volume hydraulic fracturing technique would have a significant positive economic impact at the regional and local levels. Using the same methodology described above for the statewide analysis, the FTE labor requirements needed to construct and operate these wells were estimated for each region. Table 6.35 provides the maximum direct and indirect employment impacts that are predicted to occur under each development scenario for each region.

In Region A, which is used to define an upper boundary of the regional socioeconomic impacts, it is projected that direct construction employment would range from 2,204 FTE construction workers at the maximum employment levels under the low development scenario to 8,818 FTE construction workers at the maximum employment levels under the average development scenario. The new production employment in the region is expected to range from 895 to 3,581 FTE production workers per year.

In contrast, employment impacts are not anticipated to be as large in Region C, which is used to define a lower boundary for the regional socioeconomic impacts. At the maximum employment levels under the low development scenario, an estimated 221 new FTE constructions workers and 90 new FTE production workers would be needed for drilling and maintaining the new natural gas wells. These figures would increase to 882 new FTE construction workers and 358 new FTE production workers under the average development scenario (see Table 6.35).

Table 6.35 - Maximum Direct and Indirect Employment Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Employment[1]	2,204	8,818
Production Employment[2]	895	3,581
Indirect Employment Impacts[3]	650	2,600
Total Employment Impacts	3,749	14,999
Total Employment as a Percentage of Region A's 2010 Total Labor Force	2.3%	9.3%
Region B		
Direct Employment Impacts		
Construction Employment[1]	1,014	4,056
Production Employment[2]	412	1,647
Indirect Employment Impacts[3]	191	762
Total Employment Impacts	1,617	6,465
Total Employment as a Percentage of Region B's 2010 Total Labor Force	1.8%	7.3%
Region C		
Direct Employment Impacts		
Construction Employment[1]	221	882
Production Employment[2]	90	358
Indirect Employment Impacts[3]	66	263
Total Employment Impacts	377	1,503
Total Employment as a Percentage of Region C's 2010 Total Labor Force	0.4%	1.4%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

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

2 These figures represent the maximum annual production employment under each scenario. These figures correspond to production employment in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation employment for all other years.

3 Separate Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II), were used for each region to estimate the indirect employment impacts.

Figure 6.14, Figure 6.15, and Figure 6.16 illustrate the projected direct employment in each representative region that would result from implementation of each development scenario over the 60-year time frame. The figures show how construction and production employment levels are expected to vary, with the peak direct employment occurring in Year 30.

Figure 6.14 - Projected Direct Employment in Region A Resulting from Each Development Scenario (New August 2011)

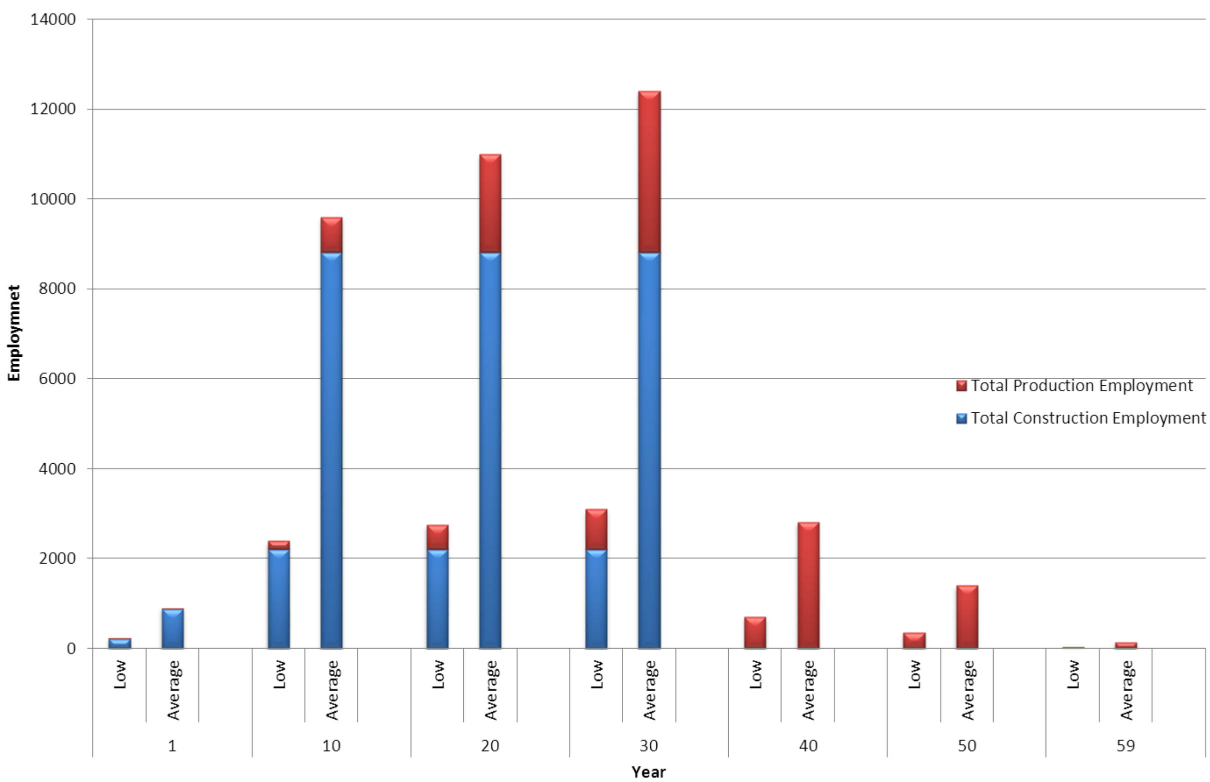


Figure 6.15 - Projected Direct Employment in Region B Resulting from Each Development Scenario (New August 2011)

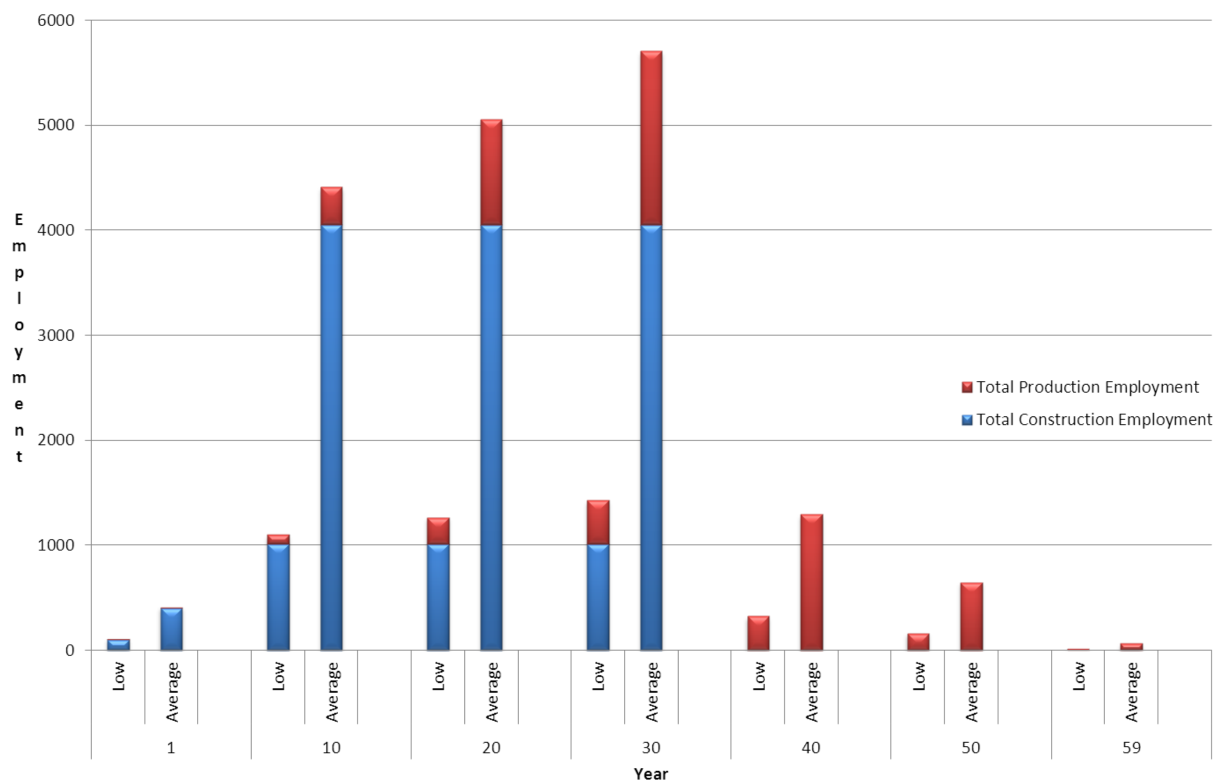
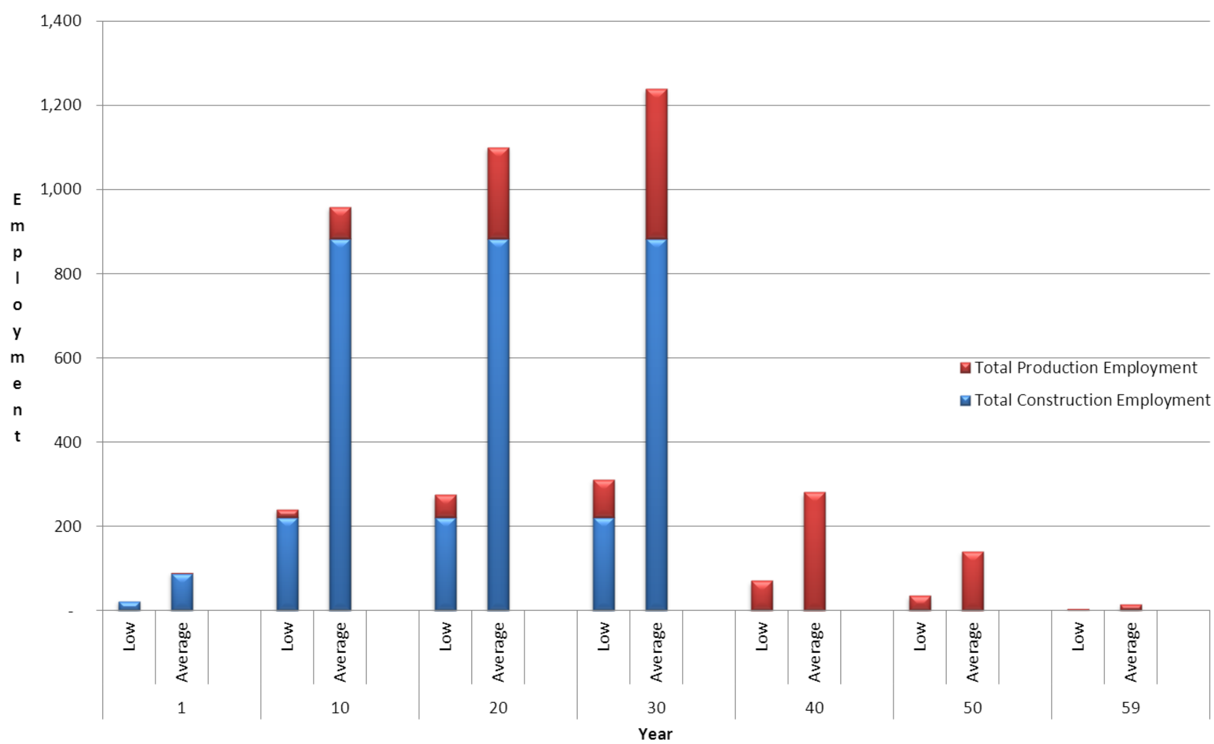


Figure 6.16 - Projected Direct Employment in Region C Resulting from Each Development Scenario (New August 2011)



As described previously for the statewide impacts, in addition to the direct employment impacts, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from regional suppliers, the overall demand for goods and services in the region would expand. Revenues at the region's wholesale and retail outlets and service providers would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the region, thus "multiplying" the positive economic impacts of the original increase in construction/operation spending. These "multiplier" effects would continue on until all of the original funds have left the region's economy through either taxes or savings, or through purchases from outside the region.

Indirect employment impacts are expected to range from a high of 650 to 2,600 indirect workers in Region A to a low of 66 to 263 indirect workers in Region C, depending on the development scenario. Direct employment multipliers of 1.4977 for Region A, 1.3272 for Region B, and 1.4657 for Region C for the oil and gas extraction industry were used in this analysis (U.S. Bureau of Economic Analysis 2011b; 2011c; 2011d). In contrast, New York State as a whole had a direct employment multiplier of 2.1766 for the oil and gas extraction industry (U.S. Bureau of Economic Analysis 2011a).

The employment and earnings multipliers in these regions are much smaller than in New York State as a whole, underscoring the fact that portions of these study areas do not have as well-developed, self-sufficient, and diverse economies as the state as a whole. In particular, the low multipliers reflect the fact that much of the goods and services that would be needed to construct and operate the new wells would be purchased outside the regions.

However, it can be expected that as the natural gas industry matures in these regions, more local suppliers and service providers would enter the markets and be able to respond to the natural gas industry's needs. As time goes by, a larger portion of the indirect economic impacts would remain in the region, further stimulating the local economies.

Figure 6.17, Figure 6.18, and Figure 6.19 graphically illustrate the projected total employment in Region A, Region B, and Region C, respectively, that would result from each development scenario. As shown on the figures, total employment levels would be greatest in Year 10 through Year 30. Once new well construction ends in Year 30, the projected direct and indirect employment would be greatly reduced.

Figure 6.17 – Projected Total Employment in Region A Under Each Development Scenario (New August 2011)

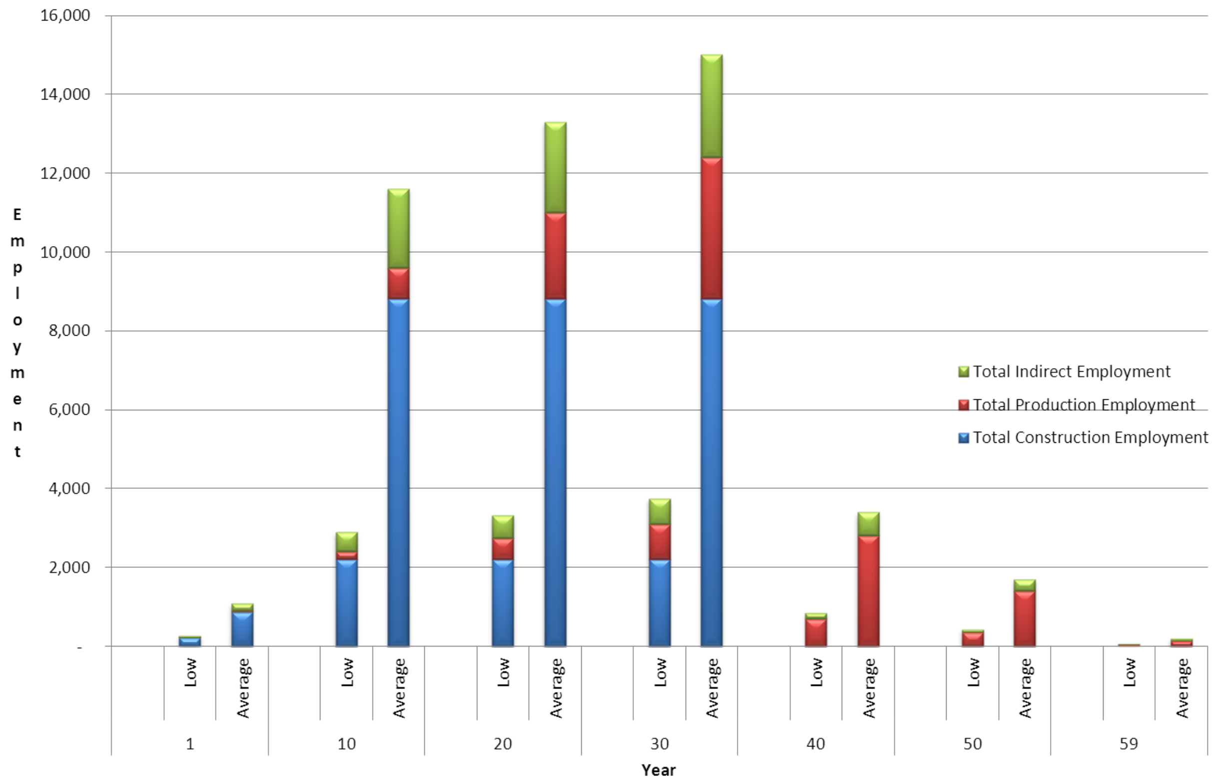


Figure 6.18 - Projected Total Employment in Region B Under Each Development Scenario (New August 2011)

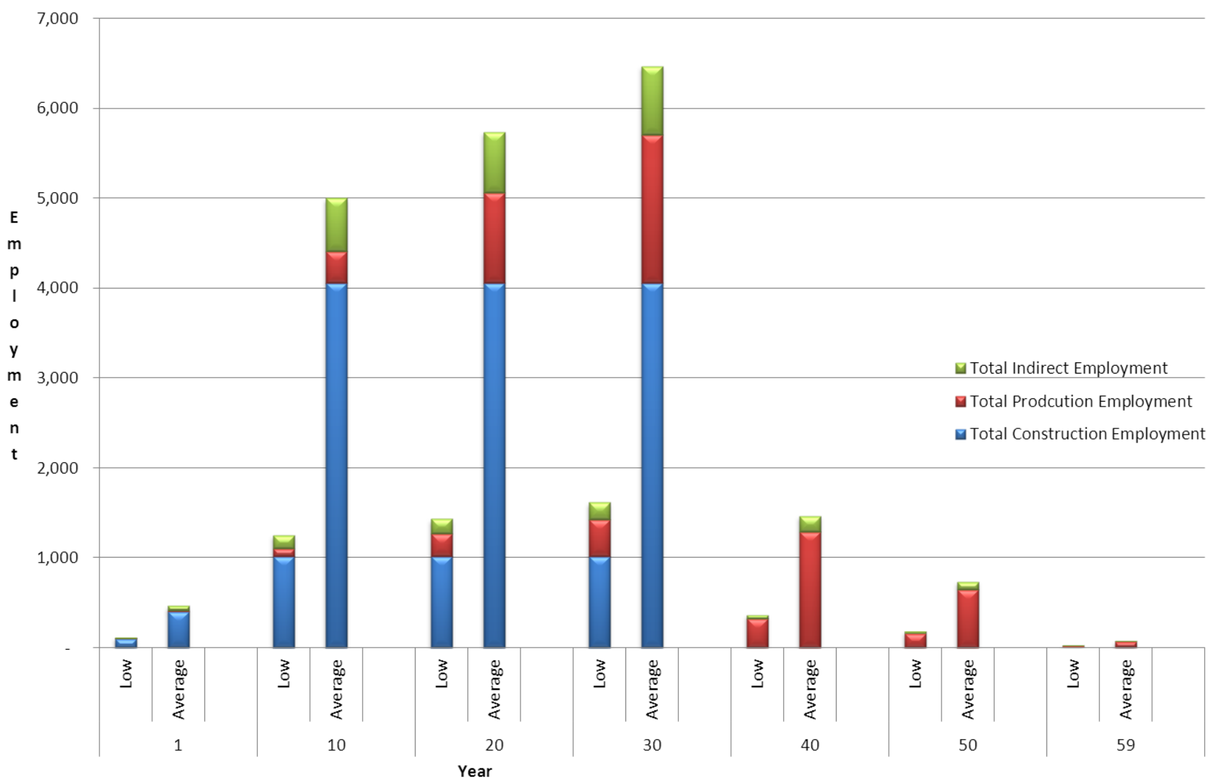
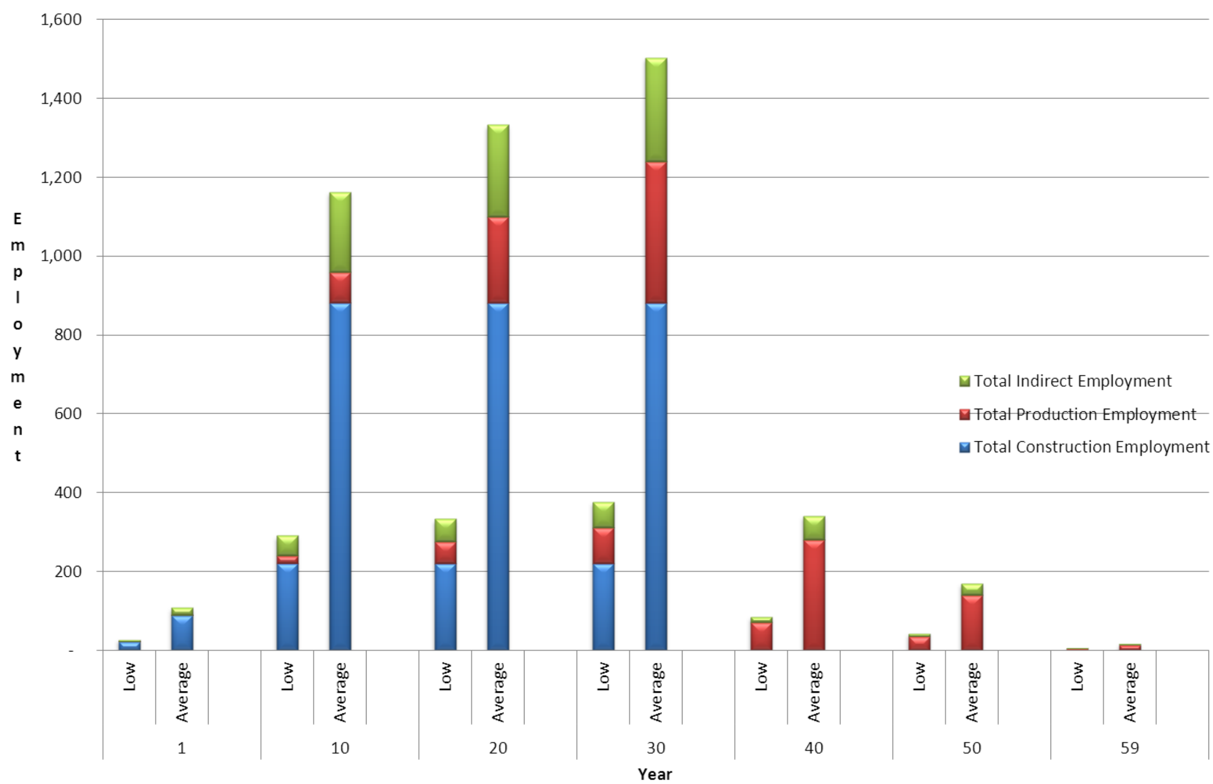


Figure 6.19 - Projected Total Employment in Region C Under Each Development Scenario (New August 2011)



The proposed use of high-volume hydraulic fracturing would have a significant, positive impact on employment in New York State as a whole and in the affected communities. However, the distribution of these positive employment impacts would not be evenly distributed throughout the state or even throughout the areas where low-permeable shale is located. Many geological and economic factors would interact to determine the exact location that wells would be drilled. The location of productive wells would determine the distribution of impacts.

In some regions in the state where drilling is most likely to occur, the increases in employment may be so large that these regions may experience some short-term labor shortages. The increase in direct and indirect employment related to the natural gas extraction industry could drive wage rates up in the areas in the short term and make it more difficult for existing industries to recruit and retain qualified workers. In addition, the increase in wage rates could have a short-term, negative impact on existing industries as it would increase their labor costs. These potential short-term labor impacts would be less severe because specialized labor from outside the region would likely be required for certain jobs, and the existence of employment opportunities would cause the migration of workers into the region. In addition, the positive employment impacts from well construction and development—and the related economic impacts derived from that employment—would generate more in-migration to the region. In time, the additional new residents to the areas would expand the regional labor force and reduce the pressure on labor costs.

Income

The increase in direct and indirect employment would have a positive impact on income levels in regions where natural gas development occurs. Table 6.36 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 to Year 30), total annual construction earnings in a region could range from a low of $15.0 million in Region C under the low development scenario to nearly $597.0 million under the average development scenario in Region A. In Year 30, the year that the maximum number of production workers are assumed to be employed, regional employee earnings from production employment could range from a low of $6.1 million in Region C under the low development scenario to a high of $242.4 million in Region A under the average development scenario.

Table 6.36 - Maximum Direct and Indirect Earnings Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Earnings[1]	$149.2	$597.0
Production Earnings[2]	$60.6	
Indirect Earnings Impacts[3]	**$44.0**	**$176.0**
Total Earnings Impacts	**$253.8**	**$1,015.4**
Total Earnings as a Percentage of Region A's 2009 Total Wages	4.7%	18.7%
Region B		
Direct Earnings Impacts		
Construction Earnings[1]	$68.6	$274.6
Production Earnings[2]	$27.9	$111.5
Indirect Earnings Impacts[3]	**$12.9**	**$51.6**

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Total Earnings Impacts	**$109.4**	**$437.7**
Total Earnings as a Percentage of Region B's 2009 Total Wages	4.8%	19.3%
Region C		
Direct Earnings Impacts		
Construction Earnings[1]	$15.0	$59.7
Production Earnings[2]	$6.1	$24.2
Indirect Earnings Impacts[3]	$4.5	$17.8
Total Earnings Impacts	$25.6	$101.7
Total Earnings as a Percent of Region C's 2009 Total Wages	0.9%	3.7%

Source: U.S. Bureau of Economic Analysis 2011b, 2011c, 2011d; NYSDOL 2009.

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

2 These figures represent the maximum annual production earnings under each development scenario. These figures correspond to production employee earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected production and indirect employee earnings for all other years.

3 Separate Type I direct earnings multipliers for the oil and gas extraction industry from the US Bureau of Economic Analysis, Regional Input- Output Modeling System (RIMS II) for each region were used to estimate the indirect employment impacts.

Total employee earnings in all of the regions are expected to increase significantly. Region A would experience annual increases in employee earnings of approximately $254 million to $1.0 billion, or 4.7% to 18.7% of the 2009 total wages and salaries for the region. Similarly, Region B would experience annual increases in employee earnings of approximately $109 million to $438 million, or 4.8% to 19.3% of 2009 total wages and salaries for the region. Region C would also experience a significant impact in its annual employee earnings. Employee earnings in this region would increase from approximately $26 million to $102 million, or 0.9% to 3.7% of the 2009 total wages and salaries for the region (see Table 6.36).

Owners of the subsurface mineral rights where wells are drilled would also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or greater of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas production is at its peak, could result in significant increases in income. In addition, mineral rights owners often receive large signing bonuses/bonus bids as part of the lease agreements.

Impacts on Other Industries

The proposed high-volume hydraulic-fracturing operations would affect not only the size of the regional economies as described above, but would also have an impact on other industries in the economy.

As previously described, suppliers of the natural gas extraction industry would experience significant increases in demand for their goods and services. Over time, these industries would expand and their importance in the regional economies would likewise increase. As shown in Section 2.4.11, Economy, Employment, and Income, the industries expected to experience the greatest indirect, or secondary, growth due to expansion of the natural gas extraction industry would be real estate; the professional, scientific, and technical industries; the management of companies and enterprises; construction; and manufacturing industries. For every $1 million change in the final demand generated in the natural gas extraction industry, a corresponding significant level of output would be generated in these industries. Typically, a change in final demand in an industry is defined as the change in output of that industry multiplied by the value or price of its output. In this case, a $1 million increase in the value of output from the natural gas extraction industry would generate $47,100 in the real estate and rental and leasing industry; $30,500 in the professional, scientific, and technical services industry; and $27,600 in the management of companies and enterprises industry. See Section 2.4.15 for a discussion of indirect impacts on other industries in New York State.

Each of these secondary industries would experience increases in their output, employment, income and value added. As a result, industries that supply these secondary industries would also experience a positive economic impact, and they would expand as demand for their goods and services increases. Secondary, and eventually even tertiary, suppliers would start to tailor their products to meet the needs of the natural gas extraction industry.

Conversely, some industries in the regional economies may contract as a result of the proposed natural gas development. Negative externalities associated with the natural gas drilling and production could have a negative impact on some industries such as tourism and agriculture. Negative changes to the amenities and aesthetics in an area could have some effect on the number of tourists that visit a region, and thereby impact the tourism industry. However, as shown by the tourism statistics provided for Region C, Cattaraugus and Chautauqua Counties still have healthy tourism sectors despite having more than 3,900 active natural gas wells in the region.

Similarly, agricultural production in the heavily developed regions may experience some decline as productive agricultural land is taken out of use and is developed by the natural gas industry. Property values also may experience some increase as a result of the natural gas development and the resulting increase in economic activity. The potential increase in land prices, which is one of the main factors of production for agriculture, could impact the industry's input costs in areas experiencing the most intense development.

6.8.2 Population

This section presents a summary of the population and demographic findings of the Economic Assessment Report (2011) written by Ecology and Environment Engineering, P.C.

As described previously, three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels. The designation of these areas as representative regions does not mean that the impacts would necessarily be limited to those areas. Until the production potential of low-permeability reservoirs is proven, it is not possible to predict where every potential high-volume hydraulically fractured well may be sited; wells could be developed anywhere there is low-permeability shale. The local and regional impacts presented here are intended only to provide order-of-magnitude estimates for the range of potential impacts. See the Economic Assessment Report for a more detailed discussion on the selection of these representative regions.

To assess the maximum potential population impacts, the discussion below is based on a hypothetical situation in which all workers hired for the construction and production phases of the natural gas wells either migrate into the regions from other areas, or workers migrate into the regions from other areas to fill positions which local construction and production workers vacate to work on the natural gas wells.. Although this hypothetical situation is used to examine the maximum potential population impacts, it is more likely that the actual outcome would be less than described. Not all workers employed during the construction and production phases would necessarily live in New York State or one of the representative regions. Particularly in the case of well development and production in the Southern Tier, existing natural gas workers currently residing in Pennsylvania, for example, may simply choose to maintain their residency in Pennsylvania and commute to work in New York.

In addition, actual population impacts may also be less than what is described in the following section because some currently unemployed or underemployed local workers could be hired to fill some of the construction and production positions, thereby, reducing the total in-migration to the region.

The hiring of currently employed local workers (i.e., those workers that leave existing jobs to work in the natural gas industry) is not expected to reduce total in-migration to the regions as it is assumed that the jobs these local workers are leaving would need to be filled. Given the finite number of workers in the regional labor force, any growth in the total number of jobs available in regional economies not filled by currently unemployed or underemployed persons would lead to in-migration to the areas.

The following additional assumptions were used to project population impacts:

- The majority of construction jobs and related population migration to the regions would be temporary and transient in nature in the beginning of the well development phase. As well construction continues, these jobs would gradually be filled by permanent residents.

- Transient construction workers are assumed to temporarily relocate to the region for a short-duration and are assumed to not be accompanied by their households. Permanent construction workers are assumed to relocate to the region for the duration of the well development phase and would be accompanied by their entire households.

- Production jobs and related population migration to the regions would be permanent and entire households would relocate to the regions.

- Natural gas development and production would not “crowd out” employment in other unrelated industrial sectors, and employment in these sectors would remain unchanged.

- Job vacancies created when local employees leave existing industries to take jobs in the natural gas extraction industry would be filled.

- The 2010 average household sizes in New York State (2.64 persons per household), Region A (2.47 persons per household), Region B (2.52 persons per household), and Region C (2.49 persons per household) were used in estimating the population impacts associated with permanent construction and production jobs (USCB 2010).

- There would be no involuntary displacement of persons due to construction of the natural gas wells, as no buildings would be demolished to make way for wells and wells need to be drilled at least 500 feet away from private wells and 100 feet from inhabitated dwellings.

6.8.2.1 New York State

Both transient and permanent population impacts are expected to occur as a result of natural gas well construction. Given the highly specialized nature of natural gas construction, workers with the skills required to complete a high-volume hydraulic fracturing operation would not be currently available in New York State or in the representative regions. If high-volume hydraulic fracturing operations were to begin in New York State, most of the skilled workers would initially need to be recruited from outside the state and would be both temporary and transient in nature.

As the industry matures and as more natural gas development occurs in the state and representative regions, more local persons would acquire the requisite skills needed for these jobs, and recruitment from within the existing labor force would therefore increase. Also, as the industry expands and development becomes more assured, the incentive for previously transient workers to become permanent residents within the state or representative regions would increase. Therefore, it would be expected that eventually there would be a decline in the number of transient construction workers and an increase in the number of permanent construction workers.

In an effort to estimate the mix of transient and permanent construction workers, data collected by the Marcellus Shale Education and Training Center on the occupational composition of the natural gas workforce and data from the U.S. Bureau of Economic Analysis' 2008 National Employment Matrix were used to help forecast the amount of local labor that would be employed in natural gas well development (Marcellus Shale Education and Training Center 2009; U.S. Bureau of Economic Analysis 2011e). Initially no more than 23% of the construction workforce is expected to be hired locally. Due to New York State's small existing natural gas industry, the remaining 77% of the workforce would have specialized skills that would most likely be unavailable among New York's labor force in Year 1. Given the newness of the industry, it is assumed that, in Year 1, 77% of the total workforce would be transient workers from outside the state.

As the natural gas industry matures the number of qualified workers in the state and representative regions would increase. This pool of qualified workers would expand as existing local residents gain the requisite skills and/or formerly transient workers permanently relocate to the state or representative regions. The total number of transient construction workers would gradually increase as the rate of well development increased until Year 10 when the maximum number of transient construction workers under both development scenarios is reached. From Years 11 to 30 the transient population would gradually decrease as a proportion of the total construction workforce. By Year 30 it is assumed that the natural gas industry would be sufficiently mature that 90% of all workers could be hired locally. Table 6.37 shows the transient, permanent, and total construction employment for select years. See the Economic Assessment Report for a more detailed discussion of how these figures were derived.

Table 6.37 - Transient, Permanent and Total Construction Employment Under Each Development Scenario for Select Years: New York State (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	342	97	439	1,370	389	1,759
5	1,517	693	2,210	6,051	2,766	8,817
10	2,409	1,999	4,408	9,639	7,995	17,634
15	1,759	2,649	4,408	7,038	10,596	17,634
20	1,181	3,227	4,408	4,725	12,909	17,634
25	740	3,668	4,408	2,959	14,675	17,634
30	441	3,967	4,408	1,763	15,871	17,634

Since the natural gas wells are expected to stay in operation for 30 years, production workers are assumed to be permanent workers who reside close to where the wells are located. Thus, these workers would live in or relocate their families to the area. Wells drilled in Year 1 are expected to remain in operation until Year 30; wells drilled in Year 30 would remain in operation until Year 60.

It is assumed that the households of permanent construction workers and production workers would, on average, be the same size as existing New York households (i.e., 2.64 persons, including the single worker). Therefore, in projecting population impacts, it is anticipated that transient construction workers would be temporary residents unaccompanied by family members, whereas permanent construction workers and all production workers would be permanent residents accompanied by an average of 1.64 family members.

Based on the above assumptions, Table 6.38 displays, for New York State as a whole and for each development scenario, the estimated transient and permanent populations resulting from construction and production activities for Years 1, 10, 20, 30, 40, 50, and 59.

Table 6.38 - Estimated Population Associated with Construction and Production Employment for Select Years: New York State (New August 2011)

		Transient Population	Permanent Population		
Production Year	**Development Scenario**	**Construction**	**Construction**	**Production**	**Total**
1	Low	342	256	18	275
	Average	1,370	1,026	74	1,100
10	Low	2,409	5,277	1,019	6,296
	Average	9,639	21,107	4,079	25,186
20	Low	1,181	8,519	2,872	11,392
	Average	4,725	34,080	11,492	45,572
30	Low	441	10,473	4,726	15,198
	Average	1,763	41,898	18,905	60,803
40	Low	0	0	3,707	3,707
	Average	0	0	14,829	14,829
50	Low	0	0	1,853	1,853
	Average	0	0	7,413	7,413
59[1]	Low	0	0	185	185
	Average	0	0	742	742

Note:

[1] Year 59 is used instead of Year 60 since it is assumed that all operational wells would cease production at the beginning of Year 60.

Under the low development scenario, between Years 10 and 30, it is projected that a maximum of 4,408 construction workers would temporarily or permanently migrate into the areas. The maximum transient construction workforce would occur in Year 10, with an estimated 2,409 transient workers. (During this same year, there would be 1,999 permanent workers relocating to the area.)   Under the average development scenario, between Years 10 and 30, it is projected that a maximum of 17,634 construction workers would temporarily or permanently migrate to the well construction areas. The maximum transient workforce would occur in Year 10, with an estimated 9,639 transient workers. (During this same time period, there would be 7,995 permanent workers relocating to the area.) The population impact of the maximum number of transient workers, 9,639 transient workers for the average development scenario, represents less than 0.1% of the total present population of New York State, indicating that transient workers would have only a minor short-term population impact at the state level.

Under the low development scenario, the number of persons permanently migrating to the impacted areas to construct and operate the wells is projected to reach its maximum of 15,198 persons during Year 30 (see Table 6.39). Under the average development scenario during Year 30, it is projected that 60,803 persons would permanently migrate to the impacted areas. Since it is assumed that permanent construction and production workers would relocate with their households, these population estimates include the permanent construction and production workers and members of their households. The maximum impact on the permanent population under the average development scenario is 60,803 persons in Year 30. This figure represents approximately 0.3% of the total present population of New York State, indicating that some long-term population impact could occur at the state level as a result of the operation of the new natural gas wells.

Table 6.39 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production: New York State (New August 2011)

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts [3]	% Increase from Total Existing 2010 Population
New York State	19,378,102	Low	2,409	>0.1%	15,198	>0.1%
		Average	9,639	>0.1%	60,803	0.3%

Notes:

1 Existing population from U.S. Census Bureau's *2010 Census of Population* (USCB 2010).

2 Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

3 Maximum operational impacts occur during production year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

According to the population projections developed by Jan K. Vink of the Cornell University Program on Applied Demographics, the population of New York State is expected to increase by 1,037,344 persons over the next 20 years (i.e., by an average of approximately 52,000 persons per year) (Cornell University 2009). Consequently, the maximum cumulative population impact of 60,803 persons, which occurs during production year 30, is slightly more than one year's projected incremental population growth for New York State.

Although the maximum population impacts would be relatively minor at the level of the whole state, natural gas wells would not be spread evenly across the state; they would be concentrated in particular areas where the influx of construction workers and production workers and their families may have more significant population impacts. Similarly, because new wells would not be developed evenly over time due to swings in well development activity, the population impacts would be greater in some years than in others.

In addition to direct employment (employment impacts from construction and production), there are projected indirect employment impacts from the development of hydraulic fracturing operations in the area underlain by the Marcellus and Utica Shales (see Section 6.10.1). Given the relatively high unemployment rates currently being experienced in these regions, it is likely that some of these new, indirectly created jobs (e.g., gas station clerks, hotel lobby personnel, etc.) would be filled by local, previously unemployed or underemployed persons. These indirect employment impacts would reduce local unemployment and help stimulate the local economies. The impacts associated with the influx of construction workers, both transient and permanent, would last as long as wells are being developed in an area, whereas the impacts associated with the production phase could last up to 60 years.

6.8.2.2 Representative Regions

Table 6.40,Table 6.41 and Table 6.42 show the estimated transient, permanent, and total construction employment for Regions A, B, and C under the low and average development scenario.

Table 6.40 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region A (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	171	48	219	686	194	880
5	758	347	1,105	3,026	1,383	4,409
10	1,205	999	2,204	4,820	3,998	8,818
15	880	1,324	2,204	3,520	5,298	8,818
20	591	1,613	2,204	2,363	6,455	8,818
25	370	1,834	2,204	1,480	7,338	8,818
30	220	1,984	2,204	882	7,936	8,818

Table 6.41 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region B (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	79	22	101	315	89	404
5	349	159	508	1,392	636	2,028
10	554	460	1,014	2,217	1,839	4,056
15	405	609	1,014	1,619	2,437	4,056
20	272	742	1,014	1,087	2,969	4,056
25	170	844	1,014	681	3,375	4,056
30	101	913	1,014	406	3,650	4,056

Table 6.42 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region C (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	17	5	22	69	19	88
5	75	35	110	303	138	441
10	121	100	221	482	400	882
15	88	133	221	352	530	882
20	59	162	221	236	646	882
25	37	184	221	148	734	882
30	22	199	221	88	794	882

Table 6.43 shows the maximum population impacts associated with transient and permanent construction workers and permanent production workers for the three representative regions. As noted above, the three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels, and the projected local and regional impacts presented here are intended to provide order-of-magnitude estimates for the range of potential impacts. In constructing Table 6.43 it was assumed, as discussed above, that a portion of the construction workers would be temporary, transient residents in an area and would not be accompanied by members of their households. The remainder of the construction workers would be permanent residents. The proportion of permanent workers to transient workers would gradually increase over time. All production workers are assumed to be permanent residents and would relocate their families to the area. Since the households of permanent construction and production workers are assumed to be the same size as average households in their respective regions, permanent workers are assumed to be accompanied by an average of 1.47 family members in Region A, 1.52 family members in Region B, and 1.49 family workers in Region C.

Table 6.43 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts [3]	% Increase from Total Existing 2010 Population
A	340,555	Low	1,205	0.4%	7,111	2.1%
		Average	4,820	1.4%	28,447	8.4%
B	187,786	Low	554	0.3%	3,339	1.8%
		Average	2,217	1.2%	13,348	7.1%
C	215,222	Low	121	<0.1%	720	0.3%
		Average	482	0.2%	2,868	1.3%

Notes:

1 Existing population from US Census Bureau's *2010 Census of Population* (USCB 2010).

2 Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

3 Maximum permanent impacts occur during production Year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

The upper bound of the potential impacts is found in Region A under the average development scenario, when in Year 10 there are projected to be 4,820 unaccompanied transient workers, representing 1.4% of the region's total population. The upper bound of the potential impacts from permanent population changes can be found in Region A under the average development scenario in Year 30, when 28,447 permanent construction and production workers and their household members would be residing in the region. This figure represents 8.4% of the existing population in Region A. According to the population projections presented in Section 2.4.11, in the absence of gas well development, Region A is expected to experience a future population decrease and to have a 2030 population of 279,675 persons, a decrease of 60,880 persons, equal to 17.9% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 28,447persons in Year 30 under the average development scenario, would offset approximately 47% of the projected population decline in Region A and would, therefore, have a beneficial impact.

Under the average development scenario, Region B is projected to have a maximum of 2,217 unaccompanied, transient construction workers and 13,348 permanent construction and production workers and their family members residing in the region. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. The maximum transient population would account for 1.2% of the existing population in Region B, and the maximum permanent population would account for 7.1% of the existing population, respectively. According to population projection figures presented in Section 2.4.11, in the absence of gas well development, Region B is expected to experience a future population decrease and to have a 2030 population of 183,031 persons, a decrease of 4,755 persons, equal to 2.5% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 13,348 persons in Year 30 under the average development scenario, would more than offset the projected population decline in Region B but would not add significantly to the existing population.

The lowest maximum potential population impact is found in Region C under the low development scenario, when in Year 10 only 121 unaccompanied, transient construction workers are expected to reside in the region. Under the same development scenario 720 permanent construction and production workers and their families would reside in Region C in Year 30, representing a total of approximately 1.3% of the existing population. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. In contrast, under the average development scenario in Year 30, Region C is projected to have a maximum of 482 unaccompanied, transient construction workers and a maximum of 2,868 permanent construction and production workers and household members in the region. The maximum transient population represents 0.2% of the existing population, and the maximum permanent population represents 1.3% of the existing population. According to population projection figures presented in Section 2.4.11, in the absence of gas well development, Region C is expected to experience a future population decrease and to have a 2030 population of 188,752 persons, a decrease of 26,470 persons, equal to 12.3% of the total existing population. The influx of permanent workers and their family members associated with gas well development, totaling 2,868 persons in Year 30 under the average development scenario, would offset more than 10% of the projected population decline in Region C and would have a small-scale beneficial impact.

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 - Maximum[1] 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 a 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 Employment[2]
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 (NYSDTF 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 (NYSDTF 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 Well[1]	$1,007,100
Annual Property Tax Payment[2]	$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 Receipts[1] 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 Impacts[135]

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 6.1and 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

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[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

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[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 SEQR 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	• 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	• 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	• 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	• 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	• 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	• 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	• 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	• 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	• 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	• 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	• 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)	• 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
Off-site periodic and temporary influx of specialized workforces at various phases of development	• 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	• 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
Off-site contractor yards or equipment storage areas or other staging areas	• 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	• 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

6.10 Noise [138]

The noise impacts associated with horizontal drilling and high volume hydraulic fracturing are, in general, similar to those addressed in the 1992 GEIS. The rigs and supporting equipment are somewhat larger than the commonly used equipment described in 1992, but with the exception of specialized downhole tools, horizontal drilling is performed using the same equipment, technology, and procedures as used for many wells that have been drilled in New York. Production-phase well site equipment is very quiet and has negligible impacts.

The greatest difference with respect to noise impacts, however, is in the duration of drilling. A horizontal well takes four to five weeks of drilling at 24 hours per day to complete. The 1992 GEIS anticipated that most wells drilled in New York with rotary rigs would be completed in less than one week, though drilling could extend two weeks or longer.

High-volume hydraulic fracturing is also of a larger scale than the water-gel fracs addressed in 1992. These were described as requiring 20,000 to 80,000 gallons of water pumped into the well at pressures of 2,000 to 3,500 pounds per square inch (psi). High-volume hydraulic fracturing of a typical horizontal well could require, on average, 3.6 million gallons of water and a maximum pumping pressure that may be as high as 10,000 to 11,000 psi. This volume and pressure would result in more pump and fluid handling noise than anticipated in 1992. The proposed process requires three to five days to complete. There was no mention of the time required for hydraulic fracturing in 1992.

There would also be significantly more trucking and associated noise involved with high-volume hydraulic fracturing than was addressed in the 1992 GEIS.

Site preparation, drilling, and hydraulic fracturing activities could result in temporary noise impacts, depending on the distance from the site to the nearest noise-sensitive receptors.

Typically, the following factors are considered when evaluating a construction noise impact:

[138] Section 6.10, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

- Difference between existing noise levels prior to construction startup and expected noise levels during construction;
- Absolute level of expected construction noise;
- Adjacent land uses; and
- The duration of construction activity.

In order to evaluate the potential noise impacts related to the drilling operation phases, a construction noise model was used to estimate noise levels at various distances from the construction site during a typical hour for each phase of construction. The algorithm in the model considered construction equipment noise specification data, usage factors, and distance. The following logarithmic equation was used to compute projected noise levels:

$$Lp1 = Lp2 + 10\log(U.F./10) - 20\log(d2/d1):$$

where:

Lp1 = the average noise level (dBA) at a distance (d2) due to the operation of a unit of equipment throughout the day;

Lp2 = the equipment noise level (dBA) at a reference distance (d1);

U.F. = a usage factor that accounts for a fraction of time an equipment unit is in use throughout the day;

d2 = the distance from the unit of equipment in feet; and

d1 = the distance at which equipment noise level data is known.

Noise levels and usage factor data for construction equipment were obtained from industry sources and government publications. Usage factors were used to account for the fact that construction equipment use is intermittent throughout the course of a normal workday.

Once the average noise level for the individual equipment unit was calculated, the contribution of all major noise-producing equipment on-site was combined to provide a composite noise level at various distances using the following formula:

$$Leq_{total} = 10\log\left(10^{\frac{Leq_1}{10}} + 10^{\frac{Leq_2}{10}} + 10^{\frac{Leq_3}{10}} ...etc.\right)$$

Using this approach, the estimated noise levels are conservative in that they do not take into consideration any noise reduction due to ground attenuation, atmospheric absorption, topography, or vegetation.

6.10.1 Access Road Construction

Newly constructed access roads are typically unpaved and are generally 20 to 40 feet wide during the construction phase and 10 to 20 feet wide during the production phase. They are constructed to efficiently provide access to the well pad while minimizing potential environmental impacts.

The estimated sound pressure levels (SPLs) produced by construction equipment that would be used to build or improve access roads are presented in Table 6.54 for various distances. The composite result is derived by assuming that all of the construction equipment listed in the table is operating at the percent utilization time listed and by combining their SPLs logarithmically.

These SPLs might temporarily occur over the course of access road construction. Such levels would not generally be considered acceptable on a permanent basis, but as a temporary, daytime occurrence, construction noise of this magnitude and duration is not likely to result in many complaints in the project area.

Table 6.54 - Estimated Construction Noise Levels at Various Distances for Access Road Construction (New August 2011)

Construction Equipment	Quantity	Usage Factor %	Lmax SPL @ 50 Feet (dBA)	Distance in Feet/SPL (dBA)					
				50 (adj.)	250	500	1,000	1,500	2,000
Excavator	2	40	81	80	66	60	54	50	48
Grader	2	40	85	84	70	64	58	54	52
Bulldozer	2	40	82	81	67	61	55	51	49
Compactor	2	20	83	79	65	59	53	49	47
Water truck	2	40	76	75	61	55	49	45	43
Dump truck	8	40	76	81	67	61	55	52	49
Loader	2	40	79	78	64	58	52	48	46
Composite Noise Level				**89**	**75**	**69**	**63**	**59**	**57**

Source: FHWA 2006.

Key:

adj = adjusted.

dBA = A-weighted decibels.

L_{max} = maximum noise level.

SPL = Sound Pressure Level.

6.10.2 Well Site Preparation

Prior to the installation of a well, the site must be cleared and graded to make room for the placement of the necessary equipment and materials to be used in drilling and developing the well. The site preparation would generate noise that is associated with a construction site, including noise from bulldozers, backhoes, and other types of construction equipment. The A-weighted SPLs for the construction equipment that typically would be utilized during well pad preparation are presented in Table 6.55 along with the estimated SPLs at various distances from the site. Such levels would not generally be considered acceptable on a permanent basis, but as a temporary, daytime occurrence, construction noise of this magnitude and duration is not likely to result in many complaints in the project area.

Table 6.55 - Estimated Construction Noise Levels at Various Distances for Well Pad Preparation (New August 2011)

Construction Equipment	Quantity	Usage Factor %	Lmax SPL @ 50 Feet (dBA)	Distance in Feet/SPL (dBA)					
				50 (adj.)	250	500	1,000	1,500	2,000
Excavator	1	40	81	77	63	57	51	47	45
Bulldozer	1	40	82	78	64	58	52	48	46
Water truck	1	40	76	72	58	52	46	42	40
Dump truck	2	40	76	75	61	55	49	45	43
Pickup truck	2	40	75	74	60	54	48	44	42
Chain saw	2	20	84	80	66	60	54	50	48
	Composite Noise Level			**84**	**70**	**64**	**58**	**55**	**52**

Source: FHWA 2006.

Key:

adj = adjusted.

dBA = A-weighted decibels.

L_{max} = maximum noise level.

SPL = Sound Pressure Level.

6.10.3 High-Volume Hydraulic Fracturing – Drilling

High-volume hydraulic fracturing involves various sources of noise. The primary sources of noise were determined to be as follows:

- Drill Rigs. Drill rigs are typically powered by diesel engines, which generate noise emissions primarily from the air intake, crankcase, and exhaust. These levels fluctuate depending on the engine speed and load.

- Air Compressors. Air compressors are typically powered by diesel engines and generate the highest level of noise over the course of drilling operations. Air compressors would be in operation virtually throughout the drilling of a well, but the actual number of operating compressors would vary. However, more compressed air capacity is required as the drilling advances.

- Tubular Preparation and Cleaning. Tubular preparation and cleaning is an operation that is conducted as drill pipe is placed into the wellbore. As tubulars are raised onto the drill floor, workers physically hammer the outside of the pipe to displace internal debris. This process, when conducted during the evening hours, seems to generate the most concern from adjacent landowners. While the decibel level is comparatively low, the acute nature of the noise is noticeable.

- Elevator Operation. Elevators are used to move drill pipe and casing into and/or out of the wellbore. During drilling, elevators are used to add additional pipe to the drill string as the depth increases. Elevators are used when the operator is removing multiple sections of pipe from the well or placing drill pipe or casing into the wellbore. Elevator operation is not a constant activity and its duration is dependent on the depth of the well bore. The decibel level is low.

- Drill Pipe Connections. As the depth of the well increases, the operator must connect additional pipe to the drill string. Most operators in the Appalachian Basins use a method known as "air-drilling." As the drill bit penetrates the rock the cuttings must be removed from the wellbore. Cuttings are removed by displacing pressurized air (from the air compressors discussed above) into the well bore. As the air is circulated back to the surface, it carries with it the rock cuttings. To connect additional pipe to the drill string, the operator will release the air pressure. It is the release of pressure that creates a higher frequency noise impact.

Once initiated, the drilling operation often continues 24 hours a day until completion and would therefore generate noise during nighttime hours, when people are generally involved in activities that require lower ambient noise levels. Certain noise-producing equipment is typically operated on a fairly continuous basis during the drilling process. The types and quantities of this equipment are presented in Table 6.56 for rotary air drilling and in Table 6.57 for horizontal drilling (see Photo 6.6), along with the estimated A-weighted individual and composite SPLs that would be experienced at various distances from the operation. An analysis of both types of drilling is included since according to industry sources, in accessing the natural gas formation, rotary air drilling is often used for the vertical section of the well and then horizontal drilling is used for making the turn and completing the horizontal section.

Table 6.56 - Estimated Construction Noise Levels at Various Distances for Rotary Air Well Drilling (New August 2011)

Construction Equipment	Quantity	Sound Power Level (dBA)	Distance in Feet/SPL[1] (dBA)					
			50 (adj.)	250	500	1,000	1,500	2,000
Drill rig drive engine	1	105	71	57	51	45	41	38
Compressors	4	105	77	63	57	51	47	45
Hurricane booster	3	81	51	37	31	25	22	19
Compressor exhaust	1	85	51	37	31	25	21	18
		Composite Noise Level	**79**	**64**	**58**	**52**	**48**	**45**

Source: Confidential Industry Source.

[1] SPL = Sound Pressure Level

Key:

adj = adjusted to quantity.

Table 6.57 - Estimated Construction Noise Levels at Various Distances for Horizontal Drilling (New August 2011)

Construction Equipment	Quantity	Sound Level	Distance	Distance in Feet/SPL (dBA)					
				50 (adj.)	250	500	1000	1500	2000
Rig drive motor	1	105[2]	0	71	57	51	45	41	38
Generator	3	81[2]	0	51	37	31	25	22	19
Top drive	1	85[1]	5	65	51	45	39	35	33
Draw works	1	74[1]	10	60	46	40	34	30	28
Triple shaker	1	85[1]	15	75	61	55	49	45	43
			Composite Noise Level	**76**	**62**	**56**	**50**	**47**	**44**

Source: Confidential Industry Source.

[1] SPL = Sound Pressure Level

Key:

adj = adjusted to quantity.

Photo 6.6 - Electric Generators, Active Drilling Site (New August 2011)

Intermittent operations that occur during drilling include tubular preparation and cleaning, elevator operation, and drill pipe connection blowdown. These shorter-duration events may occur at intervals as short as every 20 to 30 minutes during drilling. Noise associated with the drilling activities would be temporary and would end once drilling operations cease.[139]

6.10.4 High-Volume Hydraulic Fracturing – Fracturing

During the hydraulic fracturing process, water, sand, and other additives are pumped under high pressure into the formation to create fractures. To inject the required water volume and achieve the necessary pressure, up to 20 diesel-pumper trucks operating simultaneously are necessary (see Photo 6.7 and Photo 6.8). Typically the operation takes place over two to five days for a single well. Normally, hydraulic fracturing is only performed once in the life of a well. The sound level measured for a diesel- pumper truck under load ranges from 110 to 115 dBA at a distance of 3 feet. Noise from the diesel engine varies according to load and speed, but the main component of the sound spectrum is the fundamental engine rotation speed. The diesel engine

[139] Page 4, - Notice of Determination of Non-Significance – API# 31-015-22960-00, Permit 08828 (February 13, 2002)

sound spectrum, which peaks in the range of 50 Hz to 250 Hz, contains higher emissions in the lower frequencies.

Table 6.58 presents the estimated noise levels that may be experienced at various distances from a hydraulic fracturing operation, based on 20 pumper trucks operating at a sound power level of 110 dBA and 20 pumper trucks operating at a sound power level of 115 dBA.

Table 6.58 - Estimated Construction Noise Levels at Various Distances for High-Volume Hydraulic Fracturing (New August 2011)

Construction Equipment	Quantity	SPL[1] (dBA)	Distance (feet)	Quantity Adjusted Sound Level	Distance in Feet/SPL[1] (dBA)					
					50	**250**	**500**	**1000**	**1500**	**2000**
Pumper truck	20	110	3	123	99	85	79	73	69	67
Pumper truck	20	115	3	128	104	90	84	78	74	72

Source: Confidential Industry Source.

[1] SPL = Sound Pressure Level

Photo 6.7 - Truck-mounted Hydraulic Fracturing Pump (New August 2011)

Photo 6.8 - Hydraulic Fracturing of a Marcellus Shale Well Site (New August 2011)

The existing sound level in a quiet rural area at night may be as low as 30 dBA at times. Since the drilling and hydraulic fracturing operations are often conducted on a 24-hour basis, these operations, without additional noise mitigations, may result in an increase in noise of 37 to 42 dB over the quietest background at a distance of 2,000 feet. As indicated previously, according to NYSDEC guidance, sound pressure increases of more than 6 dB may require a closer analysis of impact potential, depending on existing SPLs and the character of surrounding land use and receptors, and an increase of 6 dB(A) may cause complaints. Therefore, mitigation measures would be required if increases of this nature would be experienced at a receptor location.

Table 6.59 presents the estimated duration of the various phases of activity involved in the completion of a typical installation. Multiple well pad installations would increase the drilling and hydraulic fracturing duration in a given area.

Table 6.59 - Assumed Construction and Development Times (New August 2011)

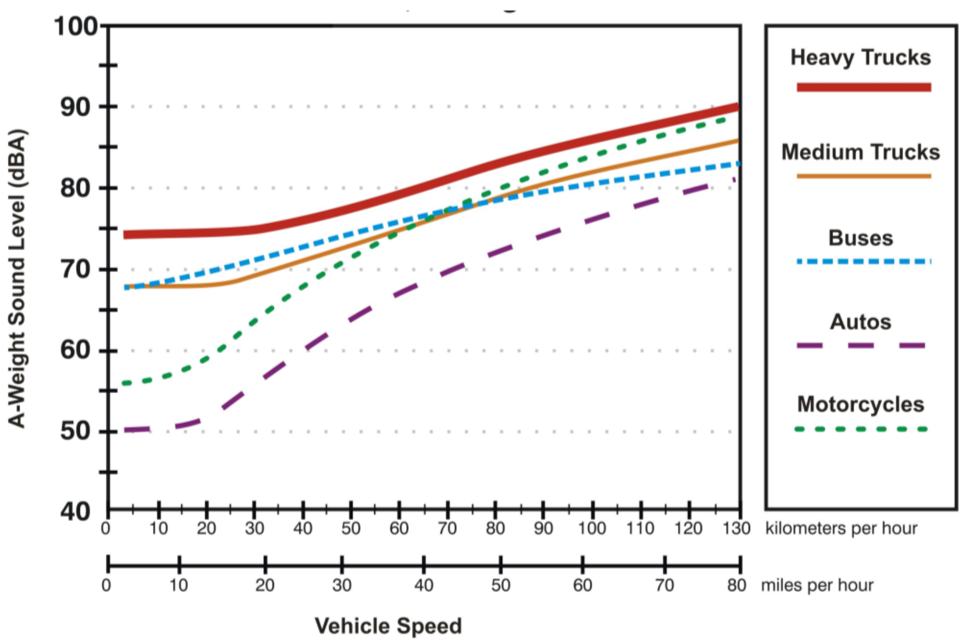
Operation	Estimated Duration (days)
Access roads	3 - 7
Site preparation/well pad	7 - 14
Well drilling	28 - 35
Hydraulic fracturing single well	2 - 5

6.10.5 Transportation

Similar to any construction operation, drill sites require the use of support equipment and vehicles. Specialized cement equipment and vehicles, water trucks, flatbed tractor trailers, and delivery and employee vehicles are the most common forms of support machinery and vehicles. Cement equipment would generate additional noise during operations, but this impact is typically short lived and is at levels below that of the compressors described above.

The noise levels generated by vehicles depend on a number of variable conditions, including vehicle type, load and speed, nature of the roadway surface, road grade, distance from the road to the receptor, topography, ground condition, and atmospheric conditions. Figure 6.20 depicts measured noise emission levels for various vehicles and cruise speeds at a distance of 50 feet on average pavement. As shown in the figure, a heavy truck passing by at 50 miles per hour would contribute a noise level of approximately 83 dBA at 50 feet from the road in comparison to a passing automobile, which would contribute approximately 73 dBA at 50 feet. Although a truck passing by would constitute a short duration noise event, multiple truck trips along a given road could result in higher hourly Leq noise levels and impacts on noise receptors close to main truck travel routes. The noise impact of truck traffic would be greater for travel along roads that do not normally have a large volume of traffic, especially truck traffic.

Figure 6.20 - A-Weighted Noise Emissions: Cruise Throttle, Average Pavement (New August 2011)



FHWA 1998.

In addition to the trucks required to deliver the drill rig and its associated equipment, trucks are used to bring in water for drilling and hydraulic fracturing, sand for hydraulic fracturing additive, and frac tanks. Trucks are also used for the removal of flowback for the site. Estimates of truck trips per well and truck trips over time during the early development phase of a horizontal and a vertical well installation are presented in Section 6.11, Transportation.

Development of multiple wells on a single pad would add substantial additional truck traffic volume in an area, which would be at least partially offset by a reduction in the number of well pads overall.

This level of truck traffic could have negative noise impacts on those living in proximity to the well site and access road. Like other noise associated with drilling, this would be temporary. Current regulations require that all wells on a multi-well pad be drilled within three years of starting the first well. Thus, it is possible that someone living in proximity to the pad would experience adverse noise impacts intermittently for up to three years.

6.10.6 Gas Well Production

Once the well has been completed and the equipment has been demobilized, the pad is partially reclaimed. The remaining wellhead production does not generate a significant level of noise.

Operation and maintenance activities could include a truck visit to empty the condensate collection tanks on an approximately weekly basis, but condensate production from the Marcellus Shale in New York is not typically expected. Mowing of the well pad area occurs approximately two times per year. These activities would result in infrequent, short-term noise events.

6.11 Transportation Impacts[140]

While the trucking for site preparation, rig, equipment, materials, and supplies is similar for horizontal drilling to what was anticipated in 1992, the water requirement of high–volume hydraulic fracturing could lead to significantly more truck traffic than was discussed in the GEIS in the regions where natural gas development would occur. This section presents (1) industry

[140] Section 6.11, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

estimates on the number of heavy- and light-duty trucks needed for horizontal well drilling as compared to vertical drilling that already takes place, (2) comparisons and reasonable scenarios with which to gauge potential impacts on the existing road system and transportation network, (3) potential impacts on roadways and the transportation network, and (4) potential impacts on rail and air service.

6.11.1 Estimated Truck Traffic

The Department requested information from the Independent Oil & Gas Association of New York (IOGA-NY) to estimate the number of truck trips associated with well construction.

6.11.1.1 Total Number of Trucks per Well

Table 6.60 presents the total estimated number of one-way (i.e., loaded) truck trips per horizontal well during construction, and Table 6.61 presents the total estimated number of one-way truck trips per vertical well during construction. Information is further provided on the distribution of light- and heavy-duty trucks for each activity associated with well construction. Table 6.62 summarizes the total overall light- and heavy-duty truck trips per well for both vertical and horizontal wells. The Department assumed that all truck trips provided in the industry estimates were one-way trips; thus, to obtain the total vehicle trips, the numbers were doubled to obtain the round-trips across the road network (Dutton and Blankenship 2010).

As discussed in 1992 regarding conventional vertical wells, trucking during the long-term production life of a horizontally drilled single or multi-well pad would be insignificant.

IOGA-NY provided estimates of truck trips for two periods of development, as shown in Table 6.60 and Table 6.61: (1) a new well location completed early on in the development life of the field, and (2) a well location completed during the peak development year. During the early well pad development, all water is assumed to be transported to the site by truck. During the peak well pad development, a portion of the wells are assumed to be accessible by pipelines for transport of the water used in the hydraulic fracturing.

As shown in comparing the number of truck trips per well in Table 6.60 and Table 6.61, the truck traffic associated with drilling a horizontal well with high-volume hydraulic fracturing is 2 to 3 times higher than the truck traffic associated with drilling a vertical well.

Table 6.60 - Estimated Number of One-Way (Loaded) Trips Per Well: Horizontal Well[1] (New August 2011)

	Early Well Pad Development (all water transported by truck)		Peak Well Pad Development (pipelines may be used for some water transport)	
Well Pad Activity	**Heavy Truck**	**Light Truck**	**Heavy Truck**	**Light Truck**
Drill pad construction	45	90	45	90
Rig mobilization[2]	95	140	95	140
Drilling fluids	45		45	
Non-rig drilling equipment	45		45	
Drilling (rig crew, etc.)	50	140	50	140
Completion chemicals	20	326	20	326
Completion equipment	5		5	
Hydraulic fracturing equipment (trucks and tanks)	175		175	
Hydraulic fracturing water hauling[3]	500		60	
Hydraulic fracturing sand	23		23	
Produced water disposal	100		17	
Final pad prep	45	50	45	50
Miscellaneous	-	85	-	85
Total One-Way, Loaded Trips Per Well	**1,148**	**831**	**625**	**795**

Source: All Consulting 2010.

1. Estimates are based on the assumption that a new well pad would be developed for each single horizontal well. However, industry expects to initially drill two wells on each well pad, which would reduce the number of truck trips. The well pad would, over time, be developed into a multi-well pad.
2. Each well would require two rigs, a vertical rig and a directional rig.
3. It was conservatively assumed that each well would use approximately 5 million gallons of water total and that all water would be trucked to the site. This is substantially greater than the likely volume of water that would be trucked to the site.

Table 6.61 - Estimated Number of One-Way (Loaded) Trips Per Well:Vertical Well (New August 2011)

Well Pad Activity	**Early Well Pad Development (all water transported by truck)**		**Peak Well Pad Development (pipelines may be used for some water transport)**	
	Heavy Truck	**Light Truck**	**Heavy Truck**	**Light Truck**
Drill pad construction	32	90	25	90
Rig mobilization	50	140	50	140
Drilling fluids	15		15	
Non-rig drilling equipment	10		10	
Drilling (rig crew, etc.)	30	70	30	70
Completion chemicals	10	72	10	72
Completion equipment	5		5	
Hydraulic fracturing equipment (trucks and tanks)	75		75	
Hydraulic fracturing water hauling	90		25	
Hydraulic fracturing sand	5		5	
Produced water disposal	42		26	
Final pad prep	34	50	34	50
Miscellaneous	0	85	0	85
Total One-Way, Loaded Trips Per Well	**398**	**507**	**310**	**507**

Source: All Consulting 2010.

Table 6.62 - Estimated Truck Volumes for Horizontal Wells Compared to Vertical Wells (New August 2011)

	Horizontal Well with High-Volume Hydraulic Fracturing		**Vertical Well**	
	Heavy Truck	**Light Truck**	**Heavy Truck**	**Light Truck**
Light-duty trips	831	795	507	507
Heavy-duty trips	1,148	625	389	310
Combined Total	**1,975**	**1,420**	**905**	**817**
Total Vehicle Trips	**3,950**	**2,840**	**1,810**	**1,634**

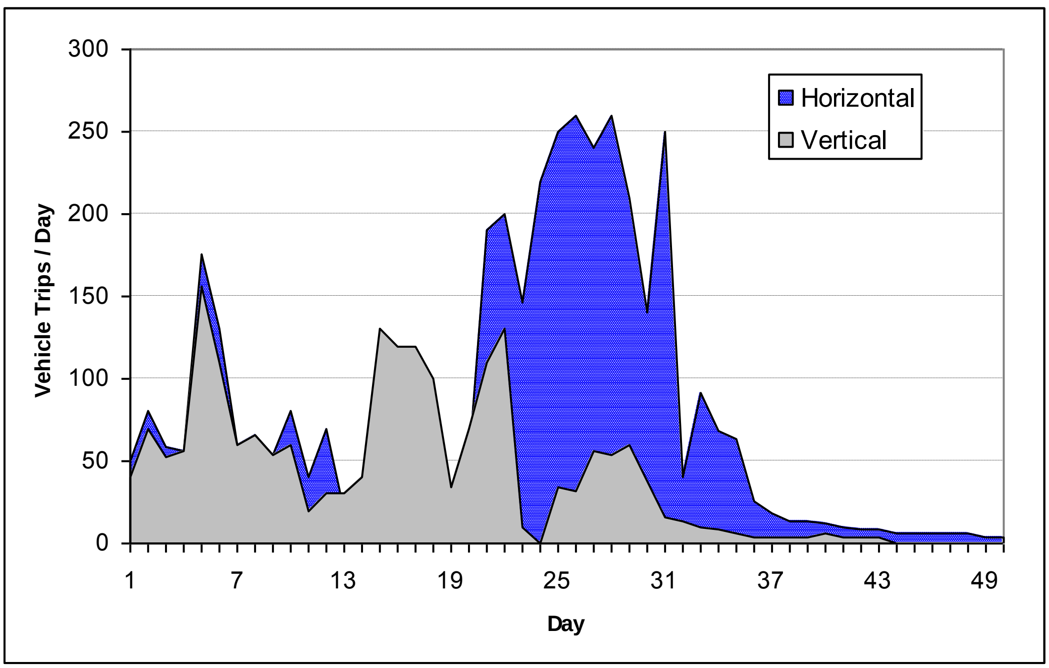
Source: Dutton and Blankenship 2010

Note: The first three rows in this table are round trips; total vehicle trips are one-way trips.

6.11.1.2 Temporal Distribution of Truck Traffic per Well

Figure 6.21 shows the daily distribution of the truck traffic over the 50-day period of early well pad development of a horizontal well and a vertical well (Dutton and Blankenship 2010). As seen in the figure, certain phases of well development require heavier truck traffic (peaks in the graph). Initial mobilization and drilling is comparable between horizontal and vertical wells; however, from Day 20 to Day 35, the horizontal well requires significantly more truck transport than the vertical well.

Figure 6.21 - Estimated Round-Trip Daily Heavy and Light Truck Traffic, by Well Type - Single Well (New August 2011)



Source: Dutton and Blankenship 2010.

6.11.1.3 Temporal Distribution of Truck Traffic for Multi-Well Pads

The initial exploratory development using horizontal wells and high-volume hydraulic fracturing would likely involve a single well on a pad. However, commercial demand would likely expand development, resulting in multiple wells being drilled on a single pad, with each horizontal well extending into a different sector of shale. Thus, horizontal wells would be able to access a larger sector of the shale from a single pad site than would be possible for traditional development with vertical wells. This means there would be less truck traffic for the development of the pad itself.

There is a tradeoff, however, as each horizontal well utilizing the high-volume hydraulic fracturing method of extraction would require more truck trips per well than vertical wells (Dutton and Blankenship 2010).

Two development scenarios were proposed to estimate the truck traffic for horizontal and vertical well development for multi-well pads (Dutton and Blankenship 2010). The key parameters and assumptions are as follows:

Multi-pad Development Scenario 1: Horizontal Wells with High-Volume Hydraulic Fracturing:

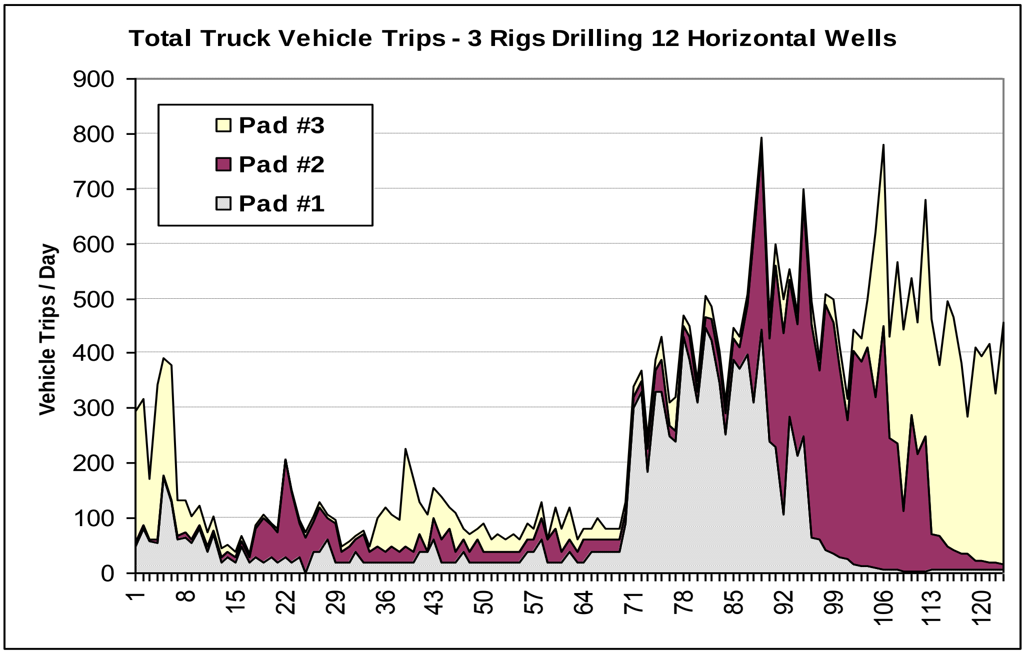
- Three rigs operated over a 120-day period.
- Each rig drills four wells in succession, then moves off to allow for completion.
- All water needed to complete the fracturing is hauled in via truck.
- Fracturing and completion of the four wells occurs sequentially and tanks are brought in once for all four wells.
- At an average of 160 acres per well, the three rigs develop a total of 1,920 acres of land.

Multi-pad Development Scenario 2: Vertical Wells

- Four rigs operated over a 120-day period
- Each rig drills four wells, moving to a new location after drilling of a well is completed.
- All water needed to complete the fracturing is hauled in via truck.
- Fracturing and completion of each well occurs after the rig relocates to a new location.
- At an average of 40 acres per well, the four rigs develop a total of 640 acres of land.

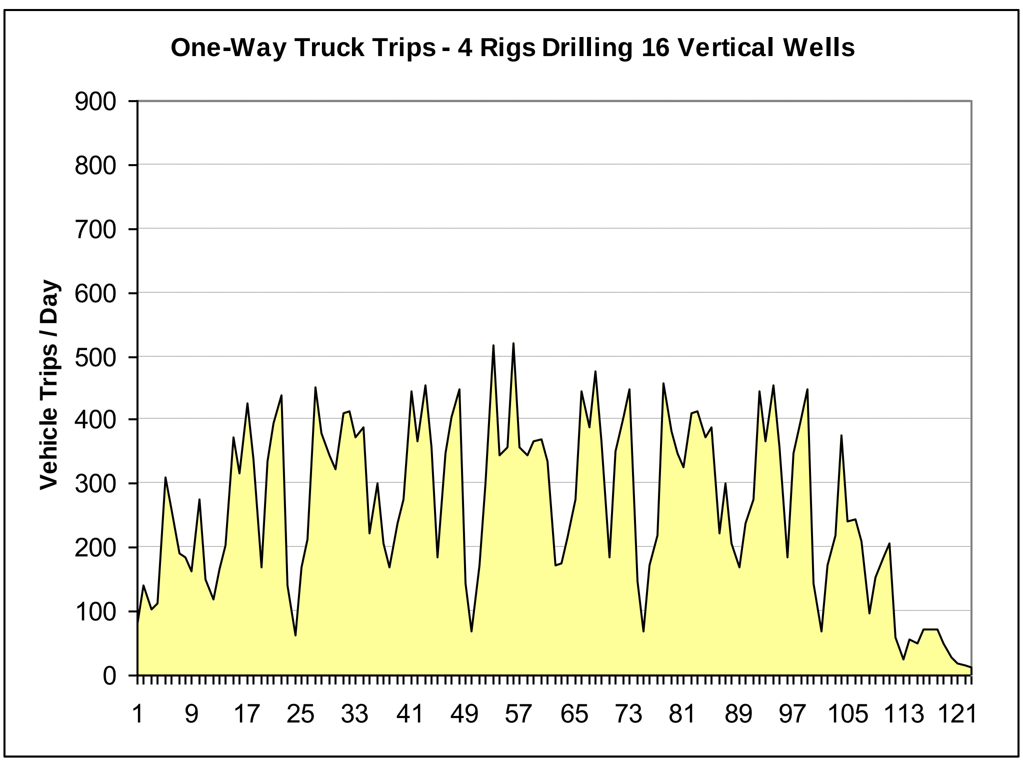
The extra yield of horizontal wells was compensated for by assuming that four vertical rigs were utilized during the same time span as three horizontal rigs. The results of these two development scenarios on a day-by-day basis are depicted in Figure 6.22 and Figure 6.23. As shown, the number of vehicle trips varies depending on the number of wells per pad. Horizontal wells have the highest volume of truck traffic in the last five weeks of well development, when fluid is utilized in high volumes. This is in contrast to the more conventional vertical wells (see Figure 6.23), where the volume of truck traffic is more consistent throughout the period of development.

Figure 6.22 - Estimated Daily Round-Trips of Heavy and Light Truck Traffic - Multi Horizontal Wells (New August 2011)



Source: Dutton and Blankenship 2010.

Figure 6.23 - Estimated Round-Trip Daily Heavy and Light Truck Traffic - Multi Vertical Wells (New August 2011)



Source: Dutton and Blankenship 2010.

The major conclusions to be drawn from this comparison of the truck traffic resulting from the use of horizontal and vertical wells are as follows (Dutton and Blankenship 2010):

- Peak-day traffic volumes given sequential completions with multiple rigs drilling horizontal wells along the same access road could be substantially higher than those for multiple rigs drilling vertical wells.

- The larger the area drained per horizontal well and the drilling of multiple wells from a pad without moving a rig offsets some of the increase in truck traffic associated with the high-volume fracturing.

- Based on industry data and other assumptions applied for these scenarios, the total number of vehicle trips generated by the three rigs drilling 12 horizontal wells is roughly equivalent to the number of vehicle trips associated with four rigs drilling 16 vertical wells. However, the horizontal wells require three-times the amount of land (1,920 acres for horizontal wells versus 640 acres for vertical wells). Thus, developing the same amount of land using vertical wells would either require three times longer, or would require deployment of 12 rigs during the same period, effectively tripling the total number of trips and result in peak daily traffic volumes above the levels associated with horizontal wells.

Based upon the information presented in these two development scenarios, utilizing horizontal wells and high-volume hydraulic fracturing rather than vertical wells to access a section of land would reduce the total amount of truck traffic. However, because vertical well hydraulic fracturing is not as efficient in its extraction of natural gas, it is not always economically feasible for operators to pursue. Currently, it is estimated that 10% of the wells drilled to develop low-permeability reservoirs with high-volume hydraulic fracturing will be vertical. Thus, the number of permits requested by applicants and issued by NYSDEC has not been fully reached. Horizontal drilling with high-volume hydraulic fracturing would be expected to result in a substantial increase in permits, well construction, and truck traffic over what is present in the current environment.

6.11.2 Increased Traffic on Roadways

As described in Section 6.18, Socioeconomics, three possible development scenarios are being assessed in this SGEIS to reflect the uncertainties associated with the future development of natural gas reserves in the Marcellus and Utica Shales – a high, medium and low development scenario. Each development scenario is defined by the number of vertical and horizontal wells drilled annually. (A summary of the development scenarios is provided in Section 6.8). Based on the number of wells estimated in each development scenario and the estimated number of truck trips per well as discussed above in Section 6.1.1, the total estimated truck trips for all wells developed annually is provided in Table 6.63. Annual trips are projected for Years 1 through 30 in 5-year increments. Estimated truck trips are provided for the three representative regions (Regions A, B, and C), New York State outside of the three regions, and statewide.

The proposed action would also have an impact on traffic on federal, state, county, regional local roadways. Given the generic nature of this analysis, and the lack of specific well pad locations to permit the identification of specific road-segment impacts, the projected increase in average annual daily traffic (AADT) and the associated impact on the level of service on specific roadway segments, interchanges, and intersections cannot be determined. The AADT on roadways can vary significantly, depending largely on functional class, and particularly whether the count was taken in heavily populated communities or in proximity to heavily traveled intersections/interchanges. Trucks traveling on higher level roadways along arterials and major collectors are not anticipated to have a significant impact on traffic patterns and traffic flow, as these roads are designed for a high level of vehicle traffic, and the anticipated increase in the level of traffic associated with this action would only represent a small, incremental change in existing conditions. However, certain local roads and minor collectors would likely experience congestion during certain times of the day or during certain periods of well development.

Table 6.64 illustrates this variation by providing the highest and lowest AADT on three functional class roads in three counties, one in each of the representative regions. The counts presented are the lowest and highest counts on the identified road in the designated functional class in the county.

On some roads, truck traffic generated by high-volume hydraulic fracturing operations may be small compared to total AADT, as would be the case on I-17 in Binghamton, where AADT was approximately 77,000 vehicles. In other cases, and particularly on collectors and minor arterials, traffic from high-volume hydraulic fracturing could be a large share of AADT. Truck traffic from high-volume hydraulic fracturing operations could also be a large share of total daily truck traffic on specific stretches of certain interstates and be much larger than existing truck volumes on lower functional class roads that serve natural gas wells or link the wells to major truck heads such as water supply, rail trans-loading, and staging areas.

Table 6.63 - Estimated Annual Heavy Truck Trips (in thousands) (New August 2011)

	Region A			Region B			Region C								
Counties	**Broome, Chemung, Tioga,**			**Delaware, Otsego, Sullivan**			**Cattaraugus, Chautauqua**			**Rest of New York State**			**State-Wide Totals**		
Low Development Scenario															
Year	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**
1	4,334	226	4,561	2,053	113	2,166	456	0	456	1,597	113	1,710	8,441	453	8,893
5	21,216	1,245	22,460	9,809	566	10,375	2,053	113	2,166	9,353	453	9,806	42,431	2,376	44,807
10	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
15	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
20	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
25	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
30	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
Average Development Scenario															
Year	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**
1	16,881	1,018	17,900	7,756	453	8,209	1,597	113	1,710	7,528	339	7,868	33,763	1,924	35,686
5	84,634	4,752	89,387	39,009	2,150	41,159	8,441	453	8,893	37,184	2,150	39,334	169,269	9,505	178,773
10	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
15	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
20	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
25	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
30	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
High Development Scenario															
Year	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**
1	25,322	1,471	26,793	11,634	679	12,313	2,509	113	2,623	11,178	566	11,744	50,644	2,829	53,473
5	126,381	7,015	133,397	58,172	3,168	61,340	12,547	679	13,226	55,663	3,055	58,718	252,763	13,917	266,680
10	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360
15	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360
20	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360
25	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360
30	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360

Table 6.64 - Illustrative AADT Range for State Roads (New August 2011)

Functional Class	County	Route	AADT Range, (1,000s)	Estimated Average Truck Volume (1,000s)
Interstate	Delaware	88	11 - 12	2.40
Arterial	Delaware	28	1 - 6	0.30
Collector	Delaware	357	2 - 4	0.02
Interstate	Broome	17	7 - 77	7.00
Arterial	Broome	26	2 - 33	1.00
Collector	Broome	41	1	0.01
Interstate	Cattaraugus	86	8 - 13	2.00
Arterial	Cattaraugus	219	6 - 11	1.00
Collector	Cattaraugus	353	1 - 6	0.20

AADT and Trucks rounded to the nearest 1,000.

Source: NYSDOT 2011

Although truck traffic is expected to significantly increase in certain locations, most of the projected trips would be short. The largest component of the truck traffic for horizontal drilling would be for water deliveries, and these would involve very short trips between the water procurement area and the well pad. Since the largest category of truck trips involve water trucks (600 of 1,148 heavy truck trips; see Table 6.60), it is anticipated that the largest impacts from truck traffic would be near the wells under construction or on local roadways.

Development of the high-volume hydraulic fracturing gas resource would also result in direct and indirect employment and population impacts, which would increase traffic on area roadways. The Department, in consultation with NYSDOT, will undertake traffic monitoring in the regions where well permit applications are most concentrated. These traffic studies and monitoring efforts will be conducted and reviewed by NYSDOT and used to inform the development of road use agreements by local governments, road repairs supported by development taxes, and other mitigation strategies described in Chapter 7.13.

6.11.3 Damage to Local Roads, Bridges, and other Infrastructure

As a result of the anticipated increase in heavy- and light-duty truck traffic, local roads in the vicinity of the well pads are expected to be damaged. Road damage could range from minor fatigue cracking (i.e., alligator cracking) to significant potholes, rutting, and complete failure of the road structure. Extra truck traffic would also result in extra required maintenance for other local road structures, such as bridges, traffic devices, and storm water runoff structures. Damage could occur as normal wear and tear, particularly from heavy trucks, as well as from trucks that may be on the margin of the road and directly running over culverts and other infrastructure that is not intended to handle such loads.

As discussed in Section 2.4.14, the different classifications of roads are constructed to accommodate different levels of service, defined by vehicle trips or vehicle class. Typically, the higher the road classification, the more stringent the design standards and the higher the grade of materials used to construct the road. The design of roads and bridges is based on the weight of vehicles that use the infrastructure. Local roads are not typically designed to sustain a high level of vehicle trips or loads and thus oftentimes have weight restrictions.

Maintenance and repair of the road infrastructure in New York currently strains the limited budgets of the New York State Department of Transportation (NYSDOT) as well as the county and local agencies responsible for local roads. Heavy trucks generally cause more damage to roads and bridges than cars or light trucks due to the weight of the vehicle. A general "rule of thumb" is that a single large truck is equivalent to the passing of 9,000 automobiles (Alaska Department of Transportation and Public Facilities 2004). The higher functional classes of roads, such as the interstate highways, generally receive better and more frequent maintenance than the local roads that are likely to receive the bulk of the heavy truck traffic from the development of shale gas.

Some wells would be located in rural areas where the existing roads are not capable of accommodating the type of truck or number of truck trips that would occur during well development. In addition, intersections, bridge capacities, bridge clearances, or other roadway features may prohibit access to a well development site under current conditions. Applicants would need to improve the roadway to accommodate the anticipated type and amount of truck traffic, which would be implemented through a road use agreement with the local municipality. This road use agreement may include an excess maintenance agreement to provide compensation for impacts. These criteria are discussed further in Section 7.13, Mitigating Transportation and

Road Use Impacts. Section 7.13 also discusses additional ways that compensatory mitigation may be applied to pay for damages.

Actual costs associated with local roads and bridges cannot be determined because these costs are a factor of (1) the number, location, and density of wells; (2) the actual truck routes and truck volumes; (3) the existing condition of the roadway; (4) the specific characteristics of the road or bridge (e.g., the number of lanes, width, pavement type, drainage type, appurtenances, etc.); and (5) the type of treatment warranted. However, based on a sample of 147 local bridges with a condition rating of 6 (i.e., Fair to Poor) in Broome, Chemung, and Tioga counties, estimates of replacement costs could range from $100,000 to $24 million per bridge, and averaged $1.5 million per bridge. The NYSDOT estimates that bridges with a condition rating of 6 or below would be impacted by the projected increase in truck traffic, resulting in accelerated deterioration, and warrant replacement. Because these routes were often built to lower standards, heavy trucks would have a much greater impact than other types of traffic.

According to the NYSDOT, the costs of repair to damaged pavement on local roads also varies widely depending on the type of work necessary and the characteristics of the road. Low-level maintenance treatments such as a single course overlay, would range from $70,000 to $150,000 per lane mile. Higher-level maintenance such as rubberizing and crack and seat rehabilitation would range from $400,000 to $530,000 per lane mile. Full--depth reconstruction can range from $490,000 to $1.9 million per lane mile.

6.11.4 Damage to State Roads, Bridges, and other Infrastructure

For roads of higher classification in the arterial or major collector categories, the general construction of the roads would be adequate to sustain the projected travel of heavy- and light-trucks associated with horizontal drilling and high-volume hydraulic fracturing. However, there would be an incremental deterioration of the expected life of these roads due to the estimated thousands of vehicle trips that would occur because of the increase in drilling activity. These larger roads are part of the public road network and have been built to service the areas of the state for passenger, commercial, and industrial traffic; however, the loads and numbers of heavy trucks proposed by this action could effectively reduce the lifespan of several roads, requiring unanticipated and early repairs or reconstruction, which would burden of the State and its taxpayers.

When the cumulative and induced impacts of the total high-volume hydraulic fracturing gas development are considered, the resulting traffic impacts can be considerable. The principal cumulative traffic impacts would occur during drilling and well development. Impacts on the road, bridge, and other infrastructure would be primarily from the cumulative impact of heavy trucking.

Actual costs to roads of higher functional classification cannot be determined because these costs are a factor of (1) the number, location and density of wells; (2) the actual truck routes and truck volumes; (3) the existing condition of the roadway; (4) the specific characteristics of the road or bridge (e.g., the number of lanes, width, pavement type, drainage type, appurtenances, etc.); and (5) the type of treatment warranted, similar to the local roads discussed above.

However, based on a sample of 166 state bridges with a condition rating of 6 (i.e., Fair to Poor) in Broome, Chemung, and Tioga counties, estimates of replacement costs could range from $100,000 to $31 million per bridge, and averaged $3.3 million per bridge. The NYSDOT estimates that bridges with a condition rating of 6 or below would be impacted by the projected increase in truck traffic, resulting in accelerated deterioration, and warrant replacement.

According to the NYSDOT, the costs of repair to damaged pavement on state roads also varies widely depending on the type of work necessary and the characteristics of the road. Low-level maintenance treatments such as a single-course overlay, would range from $90,000 to $180,000 per lane mile. Higher-level maintenance such as rubberizing and crack and seat rehabilitation would range from $540,000 to $790,000 per lane mile. Full depth reconstruction can range from $910,000 to $2.1 million per lane mile.

Depending on the volume and location of high-volume hydraulic fracturing, there is a possibility that a number of bridges and certain segments of state roads would require higher levels of maintenance and possibly replacement. The extent of such road work that would be attributable to high-volume hydraulic fracturing cannot be calculated because the proportion of truck and vehicular traffic attributable to such operations compared to truck and vehicular traffic attributable to other industries on any particular road would vary significantly. On collectors and minor arterials, there is a potential for greater impacts from this activity because these routes were often built to lower standards, and thus, heavy trucks would have a much greater impact than other types of traffic. As a result, actual contribution of heavy trucks to road and bridge deterioration would be greater than suggested by their proportion to total traffic. Conversely, any additional traffic on higher functional class roads, and especially interstates and major arterials, would result in little impact because these roads were built to higher construction and pavement standards.

6.11.5 Operational and Safety Impacts on Road Systems

An increase in the amount of truck traffic, and vehicular traffic in general, traveling on both higher and lower level local roads would most likely increase the number of accidents and breakdowns in areas experiencing well development. These potential breakdowns and accidents would require the response of public safety and other transportation-related services (e.g., tow trucks). Local road commissions and the NYSDOT would also likely incur costs associated with operational and safety improvements.

The costs of implementing operational and safety improvements on local roads would vary widely depending on the type of treatment required. Improvements on turn lanes could cost from $17,000 to $34,000, and the provision of signals and intersection could cost from approximately $35,000 for the installation of flashing red/yellow signals and from $100,000 to $150,000 for the installation of three-color signals.

The costs of addressing operational and safety impacts on state roads also would vary widely depending on the type of treatment required. The most common treatments include constructing turn lanes, with costs ranging from $20,000 to $40,000 on state roads, and installing signals and intersections, where costs range from approximately $35,000 for the installation of flashing red/yellow signals and from $100,000 to $150,000 for the installation of three-color signals.

The cost of addressing capacity and flow constraints stemming from high levels of truck traffic or direct and indirect employment and population traffic volumes are much greater, however, and might approach $1 million per lane per mile (roughly the cost of full reconstruction), not including the costs of acquiring rights-of-way.

6.11.6 Transportation of Hazardous Materials

Vertical wells do not require the volumes of chemicals that would require consideration of hazardous chemicals beyond the use of diesel fuel for the equipment on the surface. The truck traffic supporting the development of the horizontal wells involving high-volume hydraulic fracturing would be transporting a variety of equipment, supplies, and potentially hazardous materials.

As described in Section 5.4 of the SGEIS, fracturing fluid is 98% freshwater and sand and 2% or less chemical additives. There are 12 classes of chemical additives that could be in the hazardous waste water being trucked to or from a location. Additive classes include: proppant, acid, breaker, bactericide/biocide, clay stabilizer/control, corrosion inhibitor, cross linker, friction reducer, gelling agent, iron control, scale inhibitor, and surfactant. These classes are described in full detail in Section 5.4, Table 5.6. Although the composition of fracturing fluid varies from one geologic basin or formation to another, the range of additive types available for potential use remains the same. The selection may be driven by the formation and potential interactions between additives, and not all additive types would be utilized in every fracturing job (see Section 5.4). Table 5.7 (Section 5.4) shows the constituents of all hydraulic fracturing-related chemicals submitted to NYSDEC to date for potential use at shale wells within New York. Only a handful of these chemicals would be utilized at a single well. Data provided to NYSDEC to date indicates that similar fracturing fluids are needed for vertical and horizontal drilling methods.

Trucks transporting hazardous materials to the various well locations would be governed by USDOT regulations, as discussed in Section 5.5 and Chapter 8. Transportation of any hazardous materials always carries some risks from spills or accidents. Hazardous materials are moved daily across the state without incident, but the additional transport resulting from horizontal drilling poses an additional risk, which could be an adverse impact if spills occur.

6.11.7 Impacts on Rail and Air Travel

The development of high-volume hydraulic fracturing natural gas would require the movement of large quantities of pipe, drilling equipment, and other large items from other locations and from manufacturing sites that are likely far away from the well sites. Rail provides an inexpensive and efficient means of moving such material. The final movement, from rail depots to the well sites, would be accomplished with large trucks. The extent of rail and the choice of unloading locations depends on the well sites and cannot be predicted at this time. However, the use of rail to transport materials would have several predictable results:

- Total truck traffic would decrease;
- Truck traffic near the rail terminals would increase,
- Truck traffic on the arterials between the terminals and well fields would increase.

These positive and negative impacts would likely alleviate some impacts but might exacerbate impacts in neighborhoods along the routes to and from the rail centers. These impacts would require examination as part of road use agreements.

The heavy, bulky, equipment utilized for horizontal drilling would not likely be transported by air. However, the large numbers of temporary workers that the industry would employ would likely utilize the network of small airports and commuter airlines that service New York State. This would increase the traffic to and from these airports. None of the regional airports in New York State are at capacity, so the air travel is not expected to be a significant impact. In fact, the extra economic activity would be positive. However, residents that are along approach and departure corridors would experience more noise from increased service by airplanes.

6.12 Community Character Impacts[141]

High-volume hydraulic fracturing operations could potentially have a significant impact on the character of communities where drilling and production activities would occur. Both short-term and long-term, impacts could result if this potentially large-scale industry were to start operations. Experiences in Pennsylvania and West Virginia show that wholesale development of

[141] Section 6.12, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

the low-permeable shale reserves could lead to changes in the economic, demographic, and social characteristics of the affected communities.

While some of these impacts are expected to be significant, the determination of whether these impacts are positive or negative cannot be made. Change would occur in the affected communities, but how this change is viewed is subjective and would vary from individual to individual. This section, therefore, seeks to identify expected changes that could occur to the economic and social makeup of the impacted communities, but it does not attempt to make a judgment on whether such change is beneficial or harmful to the local community character.

The amount of the change in community character that is expected to occur would be impacted by several factors. However, the most important factors would be the speed at which high-volume hydraulic fracturing activities would occur and the overall level of the natural gas activities. Slow, moderate growth of the industry, if it were spread over several years, would generate much less acute impacts than rapid expansion over a limited time. Community character is constantly in a state of flux; a community's sense of place is constantly revised and adapts as social, demographic, and economic conditions change. When these changes are gradual, residents are given time to adapt and accommodate to the new conditions and typically do not view them as negative. When these changes are abrupt and dramatic, residents typically find them more adverse.

If the high-volume hydraulic fracturing operations reach some of the more optimistic development levels described in previous sections, the size and structure of the regional economies could be influenced by this new industry. Local communities that have experienced declining employment and population levels for decades could quickly become some of the fastest growing communities in the state. Traditional employment sectors could decline in importance while new employment sectors, such as the natural gas extraction industry and its suppliers, could expand in importance. Employment opportunities would increase in the communities and the types of jobs offered would change.

Total population would increase in the communities and the demographic makeup of these populations would change. In-migration resulting from the high-volume hydraulic fracturing operations would bring a racially and ethnically diverse workforce into the area. Most of the new population would be working age or their dependents. In addition, most of the employment opportunities created would be for skilled blue collar jobs.

In addition to employment and demographic impacts, the proposed high-volume hydraulic fracturing would greatly increase income and earnings throughout affected communities. Royalty payments to local landowners, increased payroll earnings from the natural gas industry, added profits to firms that supply the natural gas industry, and added earnings from all of the induced economic activity that would occur in the communities would all add to the affluence of the region. While total income in the communities would increase, this added income and wealth would not be evenly distributed. Landowners that lease out their subsurface mineral rights would benefit financially from the high-volume hydraulic fracturing operations; however, those residents that do not own the subsurface mineral rights or chose not to exploit these rights would not see the same financial benefits. Some entrepreneurs and property owners would see large financial gains from the increase in economic activity, other residents may experience a rise in living expenses without enjoying any corresponding financial gains.

In some areas, the housing market would experience an increase in value and price if there is not sufficient outstanding supply to meet the increased demand. Existing property owners would most likely benefit; residents not already property owners could experience price rises and difficulties entering the market. Additional housing would most likely be constructed in response to increased demand, and in certain instances such development could occur on currently undeveloped land. Activities that achieve lower financial returns on property, such as agriculture, may be considered less desirable compared to housing developments. While at the same time, farmers who own large tracts of land could also benefit greatly from the royalty payments on the new natural gas wells.

Local governments would see a rapid expansion in the amount of sales tax and property tax generated by gas drilling and would now have the funding to complete a wide range of community projects. At the same time, the large influx of population would demand additional community services and facilities. Existing facilities would likely become overcrowded, and additional new facilities would have to be built to accommodate this new population.

Commuting patterns in the affected communities would also change. An increase in traffic both from the added truck transportation and from the additional population would likely increase traffic on certain areas roadways and, as further explained in the Transportation subchapter, would likely lead to the need for road improvements, reconstruction and repairs.

Ambient noise levels in the communities would likely increase as a direct result of drilling and additional traffic at the well pads, and as a result of increased development in the region (see Section 2.4.13). Aesthetic resources and viewsheds could be at least temporarily impacted and changed during well pad construction and development (see Section 2.4.12).

6.13 Seismicity[142]

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

The release of energy during hydraulic fracturing produces seismic pressure waves in the subsurface. Microseismic monitoring commonly is performed to evaluate the progress of hydraulic fracturing and adjust the process, if necessary, to limit the direction and length of the induced fractures. Chapter 4 of this SGEIS presents background seismic information for New York. Concerns associated with the seismic events produced during hydraulic fracturing are discussed below.

6.13.1 Hydraulic Fracturing-Induced Seismicity

Seismic events that occur as a result of injecting fluids into the ground are termed "induced." There are two types of induced seismic events that may be triggered as a result of hydraulic fracturing. The first is energy released by the physical process of fracturing the rock which creates microseismic events that are detectable only with very sensitive monitoring equipment.

[142] Alpha, 2009, Section 7; discussion was provided for NYSERDA by Alpha Environmental, Inc., and Alpha's references are included for informational purposes.

Information collected during the microseismic events is used to evaluate the extent of fracturing and to guide the hydraulic fracturing process. This type of microseismic event is a normal part of the hydraulic fracturing process used in the development of both horizontal and vertical oil and gas wells, and by the water well industry.

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

6.13.1.1 Background

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

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

Deep well injection is a disposal technology which involves liquid waste being pumped under moderate to high pressure, several thousand feet into the subsurface, into highly saline, permeable injection zones that are confined by more shallow, impermeable strata (FRTR, August

12, 2009). The goal of deep well injection is to store the liquids in the confined formation(s) permanently.

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

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

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

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

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

The amount of displacement along a plane that is caused by hydraulic fracturing determines the resultant microseism's amplitude. The energy of one of these events is several orders of magnitude less than that of the smallest earthquake that a human can feel (Pinnacle; "Microseismic;" August 11, 2009). The smallest measurable seismic events are typically between 1.0 and 2.0 magnitude. In contrast, seismic events with magnitude 3.0 are typically large enough to be felt by people. Many induced microseisms have a negative value on the MMS. Pinnacle Technologies, Inc. has determined that the characteristic frequencies of microseisms are between 200 and 2,000 Hertz; these are high-frequency events relative to typical seismic data. These small magnitude events are monitored using extremely sensitive instruments that are positioned at the fracture depth in an offset wellbore or in the treatment well (Pinnacle; "Microseismic;" August 11, 2009). The microseisms from hydraulic fracturing can barely be measured at ground surface by the most sensitive instruments (Sharma, personal communication, August 7, 2009).

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

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

Data requirements for seismic monitoring of a hydraulic fracturing treatment include formation velocities (from a dipole sonic log or cross-well tomogram), well surface and deviation surveys, and a source shot in the treatment well to check receiver orientations, formation velocities and test capabilities. Receiver spacing is selected so that the total aperture of the array is about half the distance between the two wells. At least one receiver should be in the treatment zone, with another located above and one below this zone. Maximum observation distances for microseisms should be within approximately 2,500 feet of the treatment well; the distance is dependent upon formation properties and background noise level (Pinnacle; "FracSeis;" August 11, 2009).

6.13.1.2 Recent Investigations and Studies

Hydraulic fracturing has been used by oil and gas companies to stimulate production of vertical wells in New York State since the 1950s. Despite this long history, there are no records of induced seismicity caused by hydraulic fracturing in New York State. The only induced seismicity studies that have taken place in New York State are related to seismicity suspected to have been caused by waste fluid disposal by injection and a mine collapse, as identified in

Section 4.5.4. The seismic events induced at the Dale Brine Field (Section 4.5.4) were the result of the injection of fluids for extended periods of time at high pressure for the purpose of salt solution mining. This process is significantly different from the hydraulic fracturing process that would be undertaken for developing the Marcellus and other low-permeability shales in New York.

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

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

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

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

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

6.13.1.3 Correlations between New York and Texas

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

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

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

6.13.1.4 Affects of Seismicity on Wellbore Integrity

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

6.13.2 Summary of Potential Seismicity Impacts

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

The possibility of fluids injected during hydraulic fracturing the Marcellus or Utica Shales reaching a nearby fault and triggering a seismic event are remote for several reasons. The locations of major faults in New York have been mapped (Figure 4.13) and few major or seismically active faults exist within the fairways for the Marcellus and Utica Shales. Similarly, the paucity of historic seismic events and the low seismic risk level in the fairways for these shales indicates that geologic conditions generally are stable in these areas. By definition, faults are planes or zones of broken or fractured rock in the subsurface. The geologic conditions associated with a fault generally are unfavorable for hydraulic fracturing and economical production of natural gas. As a result, operators typically endeavor to avoid faults for both practical and economic considerations. It is prudent for an applicant for a drilling permit to evaluate and identify known, significant, mapped, faults within the area of effect of hydraulic fracturing and to present such information in the drilling permit application. It is Alpha's opinion that an independent pre-drilling seismic survey probably is unnecessary in most cases because of the relatively low level of seismic risk in the fairways of the Marcellus and Utica Shales. Additional evaluation or monitoring may be necessary if hydraulic fracturing fluids might reach a known, significant, mapped fault, such as the Clarendon-Linden fault system.

Recent research has been performed to investigate induced seismicity in an area of active hydraulic fracturing for natural gas development near Fort Worth, Texas. Studies also were performed to evaluate the cause of the earthquakes associated with the solution mining activity near the Clarendon-Linden fault system near Dale, NY in 1971. The studies indicated that the likely cause of the earthquakes was the injection of fluid for production brine disposal for the incidents in Texas, and the injection of fluid for solution mining for the incidents in Dale, NY

The studies in Texas also indicate that hydraulic fracturing is not likely the source of the earthquakes.

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

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

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

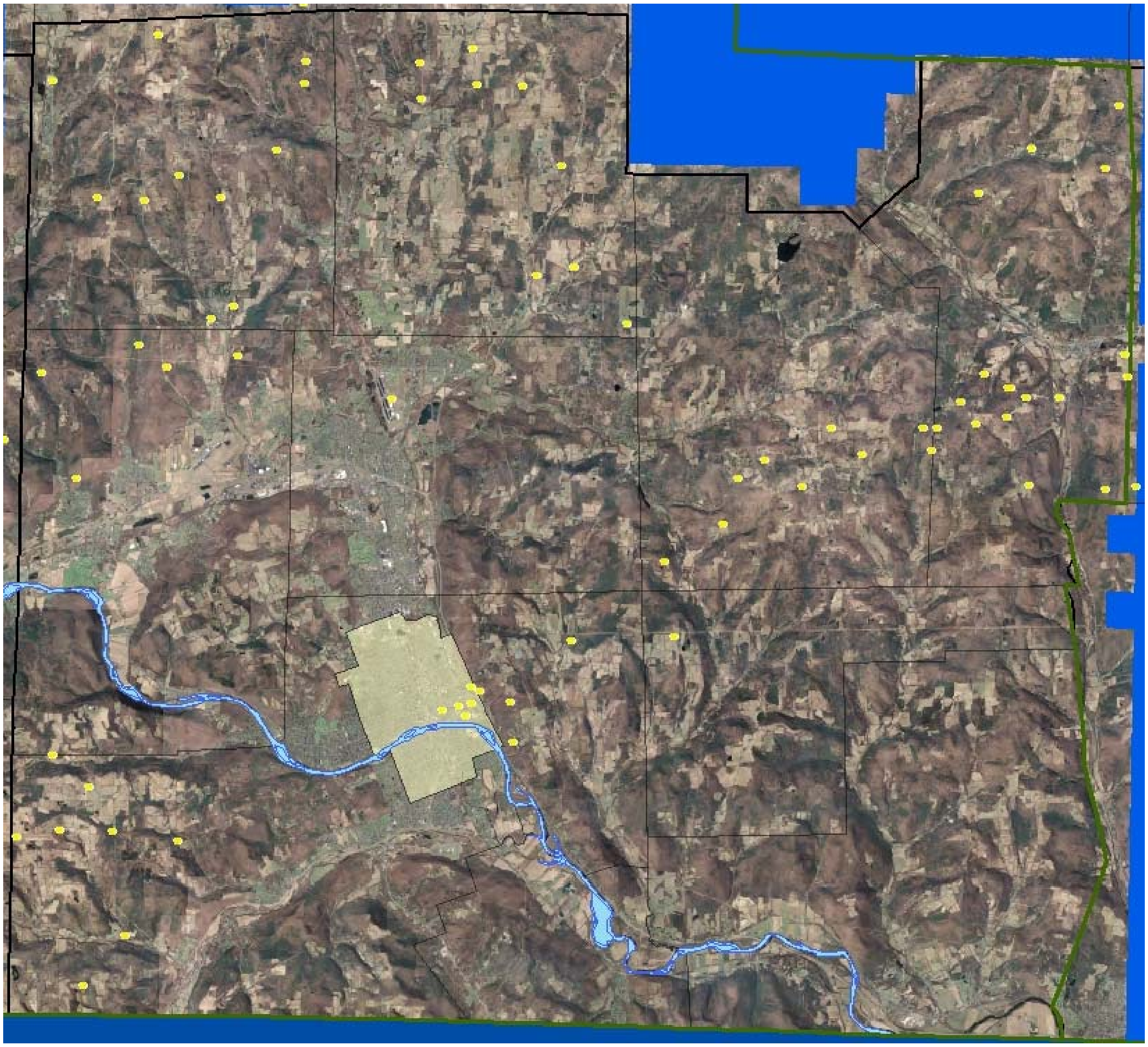
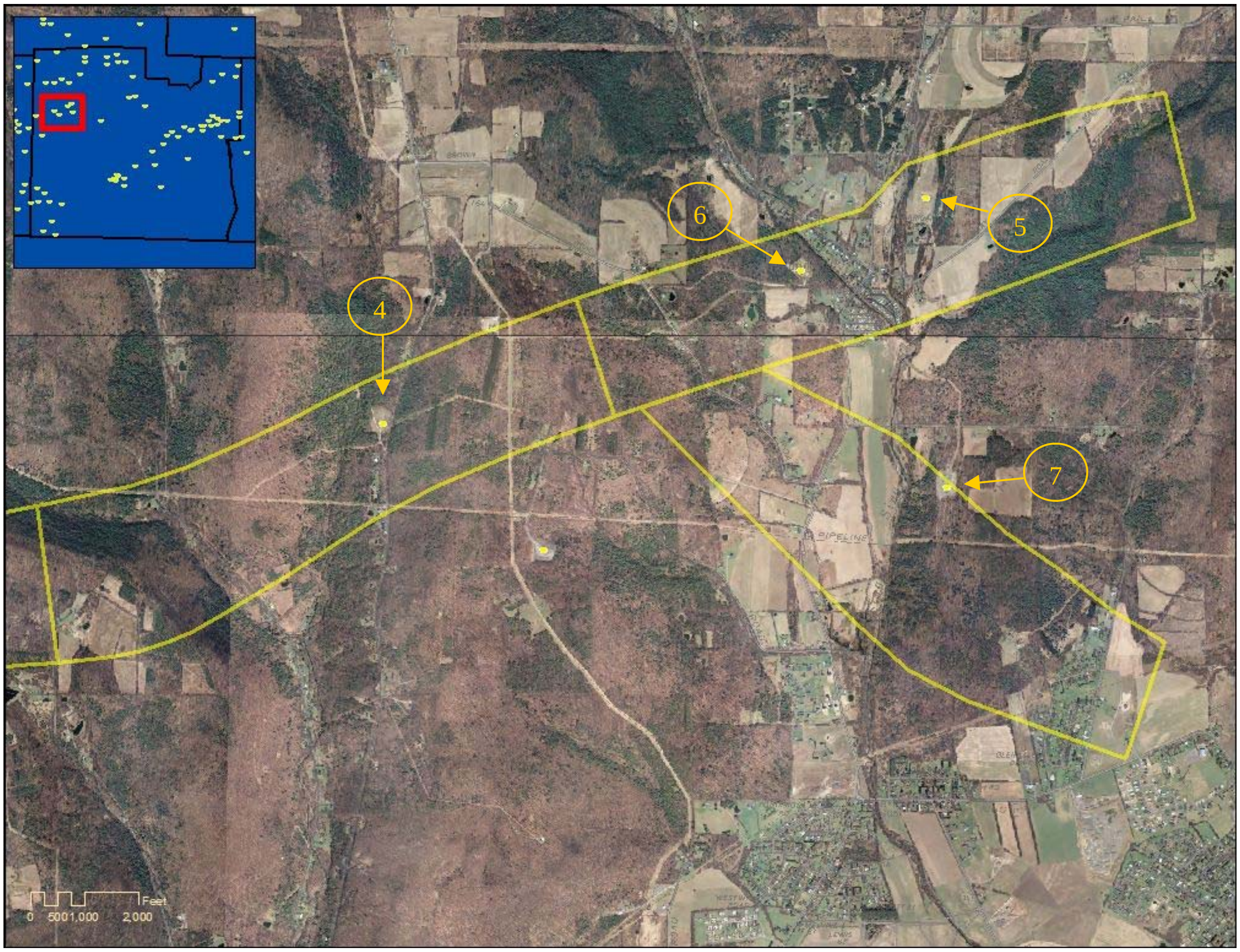


Photo 6.9 The following series of photos shows Trenton-Black River wells in Chemung County. These wells are substantially deeper than Medina wells, and are typically drilled on 640 acre units. Although the units and well pads typically contain one well, the size of the well units and pads is closer to that expected for multi-well Marcellus pads. Unlike expected Marcellus wells, Trenton-Black River wells target geologic features that are typically narrow and long. Nevertheless, photos of sections of Trenton-Black River fields provide an idea of the area of well pads within producing units.

The above photo of Chemung County shows Trenton-Black River wells and also historical wells that targeted other formations. Most of the clearings visible in this photo are agricultural fields.

Photo 6.10 The Quackenbush Hill Field is a Trenton-Black River field that runs from eastern Steuben County to north-west Chemung County. The discovery well for the field was drilled in 2000. The map below shows wells in the eastern end of the field. Note the relative proportion of well pads to area of entire well units. The unit sizes shown are approximately 640 acres, similar to expected Marcellus Shale multi-well pad units.



Photos 6.11 Well #4 (Hole number 22853) was a vertical completed in February 2001 at a true vertical depth of 9,682 feet. The drill site disturbed area was approximately 3.5 acres. The site was subsequently reclaimed to a fenced area of approximately 0.35 acres for production equipment. Because this is a single-well unit, it contains fewer tanks and other equipment than a Marcellus multi-well pad. The surface within a Trenton-Black River well fenced area is typically covered with gravel.

Rhodes 1322 11/13/2001

Rhodes 1322 5/6/2009

Photos 6.12 Well #5 (Hole number 22916) was completed as a directional well in 2002. Unit size is 636 acres. Total drill pad disturbed area was approximately 3 acres, which has been reclaimed to a fenced area of approximately 0.4 acres.

Gregory #1446A 12/27/2001

Gregory #1446A 5/6/2009

Photo 6.13 Well #6 (Hole number 23820) was drilled as a horizontal infill well in 2006 in the same unit as Well #6. Total drill pad disturbed area was approximately 3.1 acres, which has been reclaimed to a fenced area of approximately 0.4 acres.

Schwingel #2 5/6/2009

Photos 6.14 Well #7 (Hole number 23134) was completed as a horizontal well in 2004 to a true vertical depth of 9,695 and a true measured depth of 12,050 feet Well unit size is 624 acres. The drill pad disturbed area was approximately 4.2 acres which has been reclaimed to a gravel pad of approximately 1.3 acres of which approximately 0.5 acres is fenced for equipment.

Soderblom #1 8/19/2004

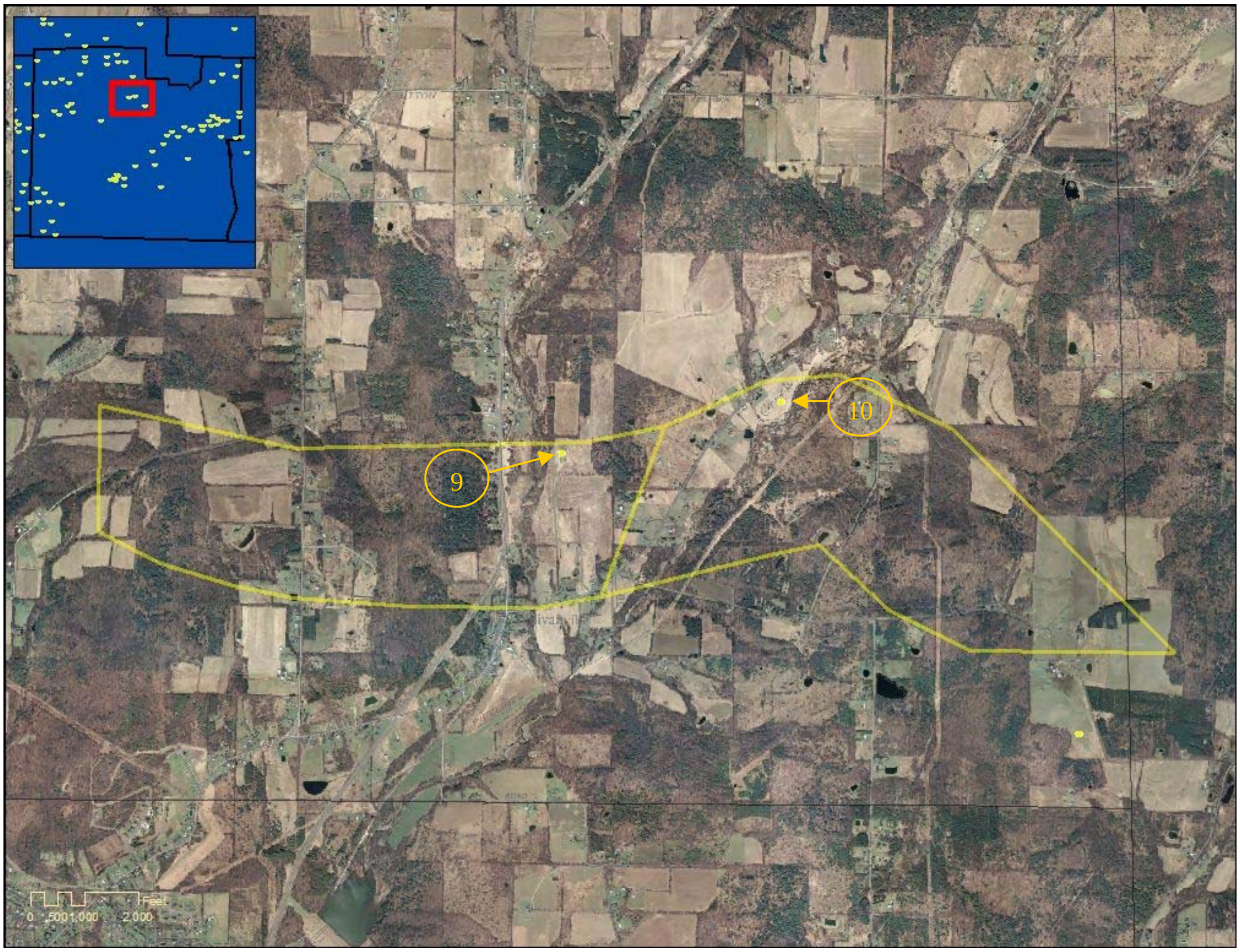
Soderblom #1 8/19/2004

Soderblom #1 5/6/2009

Soderblom #1 5/6/2009

Soderblom #1 5/6/2009

Photo 6.15 This photo shows two Trenton-Black River wells in north-central Chemung County. The two units were established as separate natural gas fields, the Veteran Hill Field and the Brick House Field.



Photos 6.16 Well #9 (Hole number 23228) was drilled as a horizontal Trenton-Black River well and completed in 2006. The well was drilled to a true vertical depth of 9,461 and a true measured depth of 12,550 feet. The well unit is approximately 622 acres.

Little 1 10/6/2005

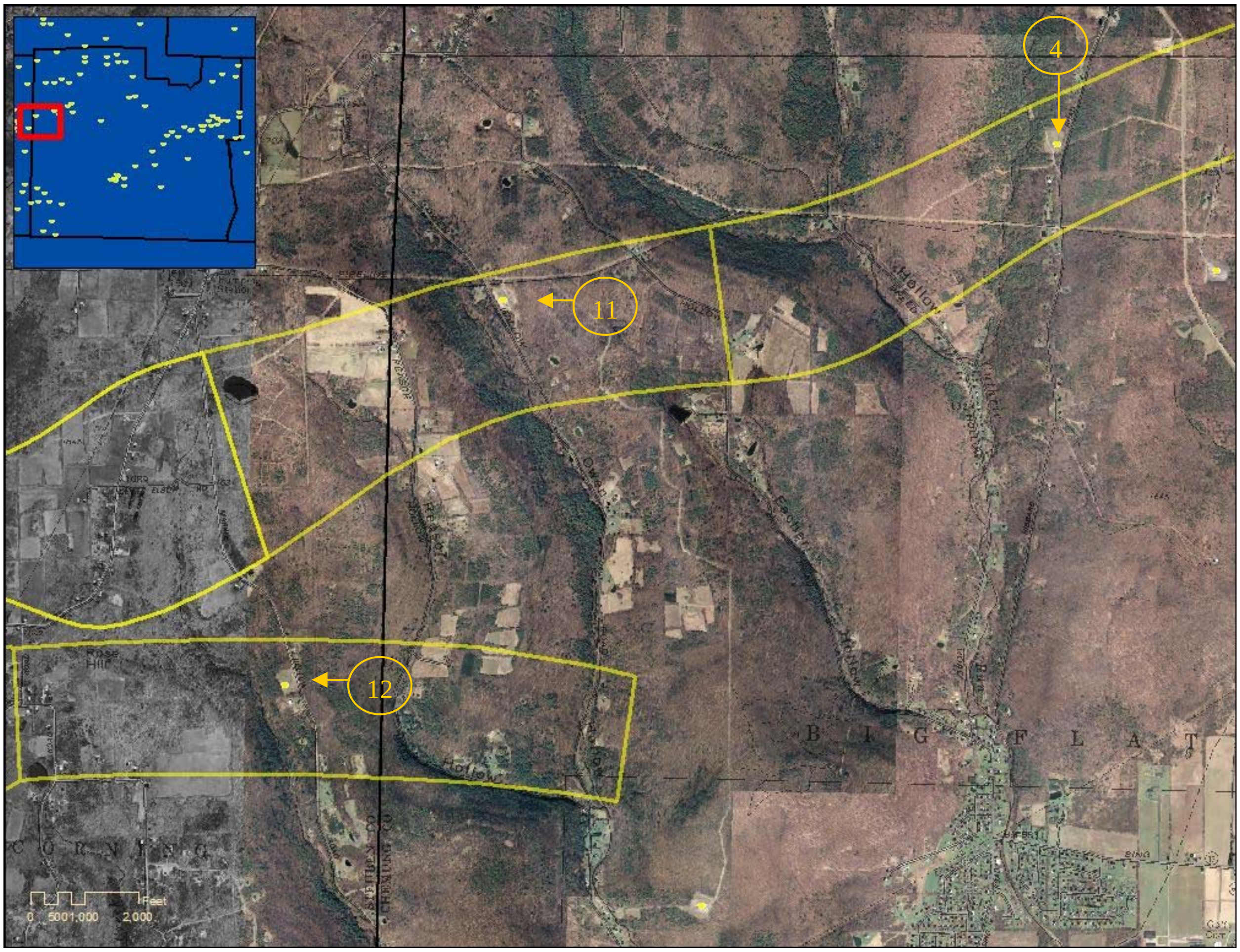
Little 1 11/3/2005

Photos 6.17 Well #10 (Hole number 23827) was drilled as a horizontal Trenton-Black River well and completed in 2006. The well was drilled to a true vertical depth of 9,062 and a true measured depth of 13,360 feet. The production unit is approximately 650 acres.

Hulett #1 10/5/2006

Hulett #1 5/6/2009

Photo 6.18 This photo shows another portion of the Quackenbush Hill Field in western Chemung County and eastern Steuben County. As with other portions of Quackenbush Hill Field, production unit sizes are approximately 640 acres each.



Photos 6.19 Well #11 (Hole number 22831) was completed in 2000 as a directional well to a total vertical depth of 9,824 feet. The drill site disturbed area was approximately 3.6 acres which has been reclaimed to a fenced area of 0.5 acres.

Lovell 11/13/2001

Lovell 5/6/2009

Photos 6.20 Well #12 (Hole number 22871) was completed in 2002 as a horizontal well to a true vertical depth of 9,955 feet and a true measured depth of 12,325 feet. The drill site disturbed area was approximately 3.2 acres which has been reclaimed to a fenced area of 0.45 acres.

Henkel 10/22/2002

Henkel 5/6/2009

New York State

DEC

Chapter 7

Mitigation Measures

Revised Draft
Supplemental Generic Environmental Impact Statement

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Chapter 7 – Mitigation Measures

FIGURES

TABLES

PHOTOS

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Chapter 7 EXISTING AND RECOMMENDED MITIGATION MEASURES

Many of the potential impacts identified in Chapter 6 are addressed and mitigated by existing regulatory programs, both within and outside of the Department. These are identified and described in this chapter, along with recommendations for additional mitigation measures to address additional potential significant adverse environmental impacts from high-volume hydraulic fracturing, which is often associated with horizontal drilling and multi-well pad development. These additional recommended mitigation measures, if adopted, can be imposed as enhanced procedures, permit conditions and/or new regulations. In addition, the proposed EAF Addendum in Appendix 6 contains a series of informational requirements, such as the disclosure of additives, the proposed volume of fluids used for fracturing, the percentage weight of water, proppants and each additive, and mandatory pre-drilling plans, that in some instances may also serve as mitigation measures. As with Chapter 6, this Supplement text is not exhaustive with respect to mitigation measures because it incorporates by reference the entire 1992 GEIS and Findings Statement and the mitigation measures identified therein. This chapter identifies and discusses:

1) mitigation of impacts not addressed by the 1992 GEIS (e.g., water withdrawal); and
2) enhancements to GEIS mitigation measures to target potential impacts associated with horizontal drilling, multi-well pad development and high-volume hydraulic fracturing.

Although every single mitigation measure provided by the 1992 GEIS is not reiterated herein, such measures remain available and applicable as warranted.

7.1 Protecting Water Resources

The Department is authorized by statute to require the drilling, casing, operation, plugging and replugging of oil and gas wells and reclamation of surrounding land to, among other things, prevent or remedy "the escape of oil, gas, brine or water out of one stratum into another" and "the pollution of fresh water supplies by oil, gas, salt water or other contaminants."[1]

[1] ECL §23-0305(8)(d).

In addition to its specific authority to regulate well operations to protect the environment, the Department also has broad authority to "[p]romote and coordinate management of water resources to assure their protection, enhancement, provision, allocation and balanced utilization . . . and take into account the cumulative impact upon all of such resources in making any determination in connection with any . . . permit . . ."[2]

7.1.1 Water Withdrawal Regulatory and Oversight Programs

Existing jurisdictions and regulatory programs address some concerns regarding the impacts related to water withdrawal that are described in Chapter 6. These programs are summarized below, followed by a discussion of three methodologies for mitigating impacts from surface water withdrawals. These are DRBC's method, SRBC's method and the Natural Flow Regime Method (NFRM), which is preferred by the Department for purposes of the development of gas reserves as described in this document and are proposed to be enforced as permit conditions until further regulatory guidance or regulations are formally adopted. Mitigation of cumulative impacts is also addressed.

7.1.1.1 Department Jurisdictions

Degradation of Water Use

Currently, the Department's regulatory authority to regulate water withdrawals outside the Great Lakes Basin and Long Island is limited to withdrawals for public water supply purposes. However, the Department proposes to require as a permit condition that applicants identify the source of the water it intends to use in high-volume hydraulic fracturing operations and report annually on the aggregate amount of water it has withdrawn or purchased. Furthermore, the Department also intends to require that permittees employ the NFRM, as described below, as a mitigation measure to avoid degradation of water quality due to water withdrawals from high-volume hydraulic fracturing.

The Water Resources bill, which was recently passed by both houses of the legislature and awaits the Governor's signature to become law, would extend the Department's authority to regulate all water withdrawals over 100,000 gpd throughout all of New York State. This bill applies to all such withdrawals where water would be used for high-volume hydraulic fracturing.

[2] ECL §3-0301(1)(b).

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. 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.

Public Water Supply - New York State currently regulates public drinking water supply ground and surface water withdrawals through the public water supply permit program.[3] These limited water supply permit programs help to protect and conserve available water supplies.

Other Water Withdrawals - The Department also regulates non-public water supply withdrawals in Long Island counties from wells with pumping capacities in excess of 45 gpm. (ECL 15-1527). All water withdrawals within New York's portion of the Great Lakes Basin of 100,000 gpd or more (30-day average) must register with the Department (ECL 15-1605). Also, all withdrawals within New York's portion of the Delaware and Susquehanna River basins greater than 100,000 gpd must have the approval of the respective basin commission. Although they may be subject to the reporting and registration requirements described below, surface and ground water withdrawals that are not on Long Island and not for drinking water supply currently are unregulated unless the withdrawals occur within the lands regulated by the DRBC and the SRBC. Surface water withdrawals are subject to the recently enacted narrative water quality standard for flow promulgated at 6 NYCRR § 703.2. This water quality standard generally prohibits any alteration in flow that would impair a fresh surface water body's designated best use.[1] Determination of an appropriate passby flow needs to be done on a case by case basis. However, guidance to clarify the application of the narrative water quality standard for flow has not yet been issued. For the purpose of this revised draft SGEIS only, the Department proposes to employ the NFRM via permit condition as a protection measure pending completion of guidance.

Water Withdrawal Reporting - Pursuant to Title 33 of Article 15 of the ECL, any entity that withdraws, or that has the capacity to withdraw, groundwater or surface water in quantities

[3] ECL Article 15, Title 15.

greater than 100,000 gpd must file an annual report with the Department. Inter-basin diversions must be reported on the same form.

Water Withdrawal Regulations

The Department primarily addresses the withdrawal of water and its potential impacts in the following regulations:

- 6 NYCRR Part 601: Water Supply;
- 6 NYCRR Part 602: Long Island Wells; and
- 6 NYCRR Part 675: Great Lakes Withdrawal Registration Regulations.

The requirements of 6 NYCRR Part 601 pertain to public water supply withdrawals and include an application that describes the project (map, engineer's report and project justification) and the proposed water withdrawal. The applicant is required to identify the source of water, projected withdrawal amounts and detailed information on rainfall and streamflow.

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

Protection of Aquatic Ecosystems

With respect to disturbances of surface water bodies such as rivers and streams, equipment or structures such as standpipes may require permits under Article 15 of the ECL. The Department has authority to control the use and protection of the waters of New York State through 6 NYCRR Part 608, Use and Protection of Waters. This regulation enables the agency to control any change, modification or disturbance to a "protected stream," which includes all navigable streams and any stream or portion of a stream with a classification or standard of AA, AA(t), A, A(t), B, B(t) or C(t), and "navigable waters." 6 NYCRR Part 608 regulates the use and protection of waters in the state, and has subparts that address the protection of fish and wildlife species. Under Part 608.2, "No person or local public corporation may change, modify or disturb any protected stream, its bed or banks, nor remove from its bed or banks sand, gravel or other material, without a permit issued pursuant to this Part." The Department reviews permits for changes, modifications, or disturbances to streams with respect to potential environmental impacts on aquatic, wetland and terrestrial habitats; unique and significant habitats; rare, threatened and endangered species habitats; water quality; hydrology; and water course and water body integrity. Part 608 does not regulate disturbances of the many streams classified as "C" or below.

7.1.1.2 Other Jurisdictions - Great Lakes-St. Lawrence River Basin Water Resources Compact

The Great Lakes-St. Lawrence River Basin Water Resources Compact (Compact) was signed into law on October 3, 2008 through Public Law 110-342. The Great Lakes-St. Lawrence River Basin Water Resources Council (Council), whose membership includes eight Great Lakes States, was established by the Compact on December 8, 2008. The Compact prohibits the bulk transport of water from that basin in containers larger than 5.7 gallons.[1] In addition, effective December 8, 2008, the Compact[4] prohibits any new or increased diversion of any amount of water out of the Great Lakes Basin with certain limited exceptions. Also, any proposed new or increased withdrawal of surface or groundwater that will result in a consumptive use of 5 million gpd or greater averaged over a 90-day period requires prior notice and consultation with the Council and the Canadian Provinces of Ontario and Quebec.

Within five years of the effective date of the Compact, New York State must implement a program that ensures that, all new and increased water withdrawals must comply with the Compact's Decision-Making Standard, Section 4.11, which establishes five criteria all water withdrawal proposals must meet, including:

1) The return of all water not otherwise consumed to the source watershed;

[4] ECL Article 21, Title 10.

2) No significant adverse individual or cumulative impacts to the quantity of the waters and water-dependent natural resources;

3) Implementation of environmentally sound and economically feasible water conservation measures;

4) Compliance with all other applicable federal, state, and local laws as well as international agreements and treaties; and

5) Reasonable proposed use of water.

The Great Lakes Council does not have regulatory authority similar to that held by SRBC and DRBC to review water withdrawals and uses and require mitigation of environmental impacts. However, the Council has specific authority for the review and/or approval of certain new and increased water withdrawals. Review by the Council will require compliance with the Compact's Decision-Making Standard and Standard for Exceptions.

7.1.1.3 Other Jurisdictions - River Basin Commissions

The SRBC and the DRBC are interstate compact entities with authority over certain water uses within discrete portions of the State. New York is a member of the Board of these river basin commissions. Those commissions with regulatory programs which address water withdrawals are described below, and mitigation measures provided by those programs are incorporated into subsequent sections.

Table 7.1 is a summary of relevant regulations for each of the governmental bodies with jurisdiction over issues related to water withdrawals. Any amount of surface water withdrawn to develop shale formations requires the approval of the SRBC and DRBC within their respective river basins. In response to increased gas drilling in Pennsylvania, SRBC has recently amended its regulations to further address gas drilling withdrawals and consumptive use. In addition to surface water withdrawals, SRBC and DRBC control diversions of water into and out of their respective basins. While ECL 15-1505 prohibits transport of water out of New York State via pipes, canals or streams without a permit from the Department, it does not specifically prohibit such transport by tanker truck. Neither SRBC nor DRBC control transfers of water from state-to-state within their basins.

Table 7.1 - Regulations Pertaining to Watershed Withdrawal (Revised July 2011)[5]

Agency	Potential Impacts of Reduced Stream Flow	Denigration of Stream's Designated Best Use	Potential Impacts to Downstream Wetlands	Potential Impacts to Fish and Wildlife	Potential Aquifer Depletion
DRBC	Water Code §2.50.2.A Water Code §2.1.1 Water Code §2.5	Water Code, 18 CFR 410 DRBC Compact	Water Code §2.350	Water Code §2.1.1 Water Code §2.200.1 Water Code §3.10.2.B Water Code §3.10.3.A.2 Water Code §3.10.3.A.2.e Water Code §3.30.4.A.1 Water Code §2.1.2 Water Code §3.10.3.A.2.b Water Code §3.20 Water Code §3.30 Water Code §3.40 Water Code §3.30.4.A.1	Water Code §2.50.2.A Water Code §2.20
NYSDEC	6 NYCRR §665 6 NYCRR §670 6 NYCRR §671 6 NYCRR §672 6 NYCRR §701	6 NYCRR §608 6 NYCRR §666 6 NYCRR §701	6 NYCRR §663 6 NYCRR §664 6 NYCRR §665	6 NYCRR §595 6 NYCRR §608 6 NYCRR §666	6 NYCRR §601 6 NYCRR §602
SRBC	Reg. of Projects §806.30 Reg. of Projects §801.3 Reg. of Projects §802.23	Reg. of Projects, 18 CFR §801, §806, §807, §808	Reg. of Projects §801.8 Reg. of Projects §806.14	Reg. of Projects §806.23.b.2 Policy 2003_1 Reg. of Projects §801.9 Reg. of Projects §806.14.b.1.v.C	Reg. of Projects §806.23.b.2 Reg. of Projects §806.12 Reg. of Projects §806.22

[5] Adapted from Alpha, 2009.

Delaware River Basin Commission Jurisdictions

Degradation of a Stream's Use - Section 3.8 of the DRBC's Compact states "No project having a substantial effect on the water resources of the basin shall hereafter be undertaken by any person, corporation or governmental authority unless it shall have been first submitted to and approved by the Commission, subject to the provisions of Sections 3.3 and 3.5. The Commission shall approve a project whenever it finds and determines that such project would not substantially impair or conflict with the Comprehensive Plan and may modify and approve as modified, or may disapprove any such project whenever it finds and determines that the project would substantially impair or conflict with such Plan." DRBC regulations work collectively to protect Delaware River Basin streams from sources of degradation that would affect the best usage. The DRBC Water Code[6] provides the regulations, requirements, and programs enacted into law that serve to facilitate the protection of these water resources in the Basin.

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

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

[6] 18 CFR Part 410.

Impacts to Aquatic Ecosystems - DRBC regulations concerning the protection of fish and wildlife are located in the Delaware River Basin Water Code.[7] In general, DRBC regulations require that the quality of waters in the Delaware basin be maintained "in a safe and satisfactory condition…for wildlife, fish, and other aquatic life" (DRBC Water Code, Article 2.200.1).

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

All surface waters in the Delaware River Basin are subject to the water quality standards outlined in the Water Code. The quality of Basin waters, except intermittent streams, is required by Article 3.10.2B to be maintained in a safe and satisfactory condition for wildlife, fish and other aquatic life. Certain bodies of water in the Basin are classified as Special Protection Waters (also referred to as Outstanding Basin Waters and Significant Resource Waters) and are subject to more stringent water quality regulations. Article 3.10.3.A.2 defines Special Protection Waters as having especially high scenic, recreational, ecological, and/or water supply values. Per Article 3.10.3.A.2.b, no measureable change to existing water quality is permitted at these locations. Under certain circumstances wastewater may be discharged to Special Protection Areas within the watershed; however, it is discouraged and subject to review and approval by the Commission. These discharges are required to have a National Pollutant Discharge Elimination System (NPDES) permit. Non-point source pollution within the Basin that discharges into Special Protection Areas must submit for approval a Non-Point Source Pollution Control Plan.[8]

Interstate streams (tidal and non-tidal) and groundwater (basin wide) water quality parameters are specifically regulated under the DRBC Water Code Articles 3.20, 3.30, and 3.40, respectively. Interstate non-tidal streams are required to be maintained in a safe and satisfactory condition for the maintenance and propagation of resident game fish and other aquatic life,

[7] 18 CFR Part 410.

[8] DRBC Water Code, Article 3.10.3.A.2.e.

maintenance and propagation of trout, spawning and nursery habitat for anadromous fish, and wildlife. Interstate tidal streams are required to be maintained in a safe and satisfactory condition for the maintenance and propagation of resident fish and other aquatic life, passage of anadromous fish, and wildlife. Groundwater is required to be maintained in a safe and satisfactory condition for use as a source of surface water suitable for wildlife, fish and other aquatic life. It shall be "free from substances or properties in concentrations or combinations which are toxic or harmful to human, animal, plant, or aquatic life, or that produce color, taste, or odor of the waters."[9]

Impacts to Wetlands - DRBC regulations concerning potential impacts to downstream wetlands are located in the Delaware River Basin Water Code[10] addressed under Article 2.350, Wetlands Protection. It is the policy of the DRBC to support the preservation and protection of wetlands by:

1) Minimizing adverse alterations in the quantity and quality of the underlying soils and natural flow of waters that nourish wetlands;

2) Safeguarding against adverse draining, dredging or filling practices, liquid or solid waste management practices, and siltation;

3) Preventing the excessive addition of pesticides, salts or toxic materials arising from non-point source wastes; and

4) Preventing destructive construction activities generally.

Item 1 directly addresses wetlands downstream of a proposed water withdrawal.

The DRBC reviews projects affecting 25 acres or more of wetlands.[11] Projects affecting less than 25 acres are reviewed by the DRBC only if no state or federal review and permit system is in place, and the project is determined to be of major significance by the DRBC. Additionally, the DRBC will review state or federal actions that may not adequately reflect the Commission's policy for wetlands in the basin.

[9] DRBC Water Code, Article 3.40.4.A.1.

[10] 18 CFR 410.

[11] DRBC Water Code, Article 2.350.4.

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

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

Groundwater withdrawals from aquifers in the Basin that exceed 100,000 gpd during any 30-day period are required be metered, recorded, and reported to the designated state agencies. Withdrawals are to be measured by means of an automatic continuous recording device, flow meter, or other method, and must be measured to within 5 % of actual flow. Withdrawals must be recorded on a biweekly basis and reported as monthly totals annually. More frequent recording or reporting may be required by the designated agency or the DRBC (DRBC Water Code, 2.50.2.A).

SRBC Jurisdictions

Degradation of a Stream's Use - The SRBC has been granted statutory authority to regulate the conservation, utilization, development, management, and control of water and related natural resources of the Susquehanna River Basin and the activities within the basin that potentially affect those resources. The SRBC controls allocations, diversions, withdrawals, and releases of water in the basin to maintain the appropriate quantity of water. The SRBC Regulation of Projects[12] provides the details of the programs and requirements that are in effect to achieve the goals of the commission.

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

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

Impacts to Aquatic Ecosystems - SRBC regulations concerning the protection of fish and wildlife are located in the SRBC Regulation of Projects.[13] In general, the Commission promotes sound

[12] 18CFR, Parts 801, 806, 807, and 808.

[13] 18 CFR Parts 801, 806, 807, and 808.

practices of watershed management for the purposes of improving fish and wildlife habitat (SRBC Regulation of Projects, Article 801.9).

Projects requiring review and approval of the SRBC under §§ 806.4, 806.5, or 806.6 are required to submit to the Commission a water withdrawal application. Applications are required to contain the anticipated impact of the proposed project on fish and wildlife (SRBC Regulation of Projects, Article 806.14.b.1.v.C). "The Commission may deny an application, limit or condition an approval to ensure that the withdrawal will not cause significant adverse impacts to the water resources of the basin."[14] The SRBC considers water quality degradation affecting fish, wildlife or other living resources or their habitat to be grounds for application denial.

Water withdrawal from the Susquehanna River Basin is governed by passby flow requirements that can be found in the SRBC Policy Document 2003-1, "Guidelines for Using and Determining Passby Flows and Conservation Releases for Surface-water and Ground-water Withdrawal Approvals." A passby flow is a prescribed quantity of flow that must be allowed to pass a prescribed point downstream from a water supply intake at any time during which a withdrawal is occurring. The methods by which passby flows are determined for use as impact mitigation are described below.

Impacts to Wetlands - Sponsors of projects requiring review and approval of the SRBC under §§ 806.4, 806.5, or 806.6 are required to submit to the Commission a water withdrawal application. Applications are required to contain the anticipated impact of the proposed project on surface water characteristics, and on threatened or endangered species and their habitats.[15]

Aquifer Depletion - Evaluation of ground water resources includes an aquifer testing protocol to evaluate whether well(s) can provide the desired yield and assess the impacts of pumping. The protocol includes step drawdown testing and a constant rate pumping test. Monitoring requirements of ground water and surface water are described in the protocol and analysis of the test data is required. This analysis typically includes long term yield and drawdown projection and assessment of pumping impacts.

[14] SRBC Regulation of Projects, Article 806.23.b.2.

[15] SRBC Regulation of Projects, Article 806.14.

7.1.1.4 Impact Mitigation Measures for Surface Water Withdrawals

Protecting Stream Flows –DRBC Method

DRBC has the charge of conserving water throughout the Delaware basin by reducing the likelihood of severe low stream flows that can adversely affect fish and wildlife resources and recreational enjoyment (18 CFR Part 410, section 2.2.1). The DRBC currently has no specific passby regulation or policy. Prescribed reservoir releases play an important role in Delaware River flow. The DRBC uses a Q7-10 flow for water resource evaluation purposes. The Q7-10 flow is the drought flow equal to the lowest mean flow for seven consecutive days, that has a 10-year recurrence interval.

The Q7-10 is a flow statistic developed by sanitary engineers to simulate drought conditions in water quality modeling when evaluating waste load assimilative capacity (e.g., for point sources from waste water treatment plants). Q7-10 is not meant to establish a direct relation between Q7-10 and aquatic life protection.[16] For most streams, the Q7-10 flow is less than 10% of the average annual flow and may result in degradation of aquatic communities if it becomes established as the only flow protected in a stream.[17]

Protecting Stream Flows – SRBC Method

The SRBC requires that passby flows, i.e., prescribed quantities of flow that must be allowed to pass a prescribed downstream point, be provided as mitigation for water withdrawals. This requirement is prescribed in part to conserve fish and wildlife habitats. "Approved surface-water withdrawals from small impoundments, intake dams, continuously flowing springs, or other intake structures in applicable streams will include conditions that require minimum passby flows. Approved groundwater withdrawals from wells that, based on an analysis of the 120-day drawdown without recharge, impact streamflow, or for which a reversal of the hydraulic gradient adjacent to a stream (within the course of a 48-hour pumping test) is indicated, also will include conditions that require minimum passby flows."[18] There are three exceptions to the required passby flow rules stated above:

[16] Camp, Dresser and McKee, 1986.

[17] Tennant 1976a,b.

[18] SRBC, Policy 2003-01.

1) If the surface-water withdrawal or groundwater withdrawal impact is minimal in comparison to the natural or continuously augmented flows of a stream or river, no passby flow will be required. Minimal is defined by SRBC as 10 % or less of the natural or continuously augmented 7-day, 10-year low flow (Q7-10) of the stream or river;

2) For projects requiring Commission review and approval for an existing surface-water withdrawal where a passby flow is required, but where a passby flow has historically not been maintained, withdrawals exceeding 10 % of the Q7-10 low flow will be permitted whenever flows naturally exceed the passby flow requirement plus the taking. Whenever stream flows naturally drop below the passby flow requirement plus the taking, both the quantity and the rate of the withdrawal will be reduced to less than 10 % of the Q7-10 low flow; and

3) If a surface-water withdrawal is made from one or more impoundments (in series) fed by a stream, or if a ground-water withdrawal impacts one or more impoundments fed by a stream, a passby flow, as determined by the criteria discussed below or the natural flow, whichever is less, will be maintained from the most downstream impoundment at all times during which there is inflow into the impoundment or series of impoundments.

In cases where passby flow is required, the following criteria are to be used to determine the appropriate passby flow for SRBC-Classified Exceptional Value (EV) Waters, High Quality (HQ) Waters, and Cold-Water Fishery (CWF) Waters; For EV Waters, withdrawals may not cause greater than 5 % loss of habitat. For HQ Waters, withdrawals may not cause greater than 5 % loss of habitat as well; however, a habitat loss of 7.5 % may be allowed if:

1) The project is in compliance with the Commission's water conservation regulations of Section 804.20;

2) No feasible alternative source is available; and

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

For Class B,[19] CWF Waters, withdrawals may not cause greater than a 10 % loss of habitat. For Classes C and D, CWF Waters, withdrawals may not cause greater than a 15 % loss of habitat. For areas of the Susquehanna River Basin not covered by the above regulations, the following shall apply:

[19] Water classifications referenced in this section are those established by State of PA which are not equivalent to NYS stream classifications.

1) On all EV and HQ streams, and those streams with naturally reproducing trout populations, a passby flow of 25 % of average daily flow will be maintained downstream from the point of withdrawal whenever withdrawals are made;

2) On all streams not covered in Item 1 above and which are not degraded by acid mine drainage, a passby flow of 20 % of average daily flow will be maintained downstream from the point of withdrawal whenever withdrawals are made. These streams generally include both trout stocking and warm-water fishery uses;

3) On all streams partially impaired by acid mine drainage, but in which some aquatic life exists, a passby flow of 15 % of ADF will be maintained downstream from the point of withdrawal whenever withdrawals are made; and

4) Under no conditions shall the passby flow be less than the Q7-10 flow.

5) The SRBC is currently reevaluating the passby requirements described above and draft changes will likely be proposed sometime in 2011.

Protecting Stream Flows - NFRM

The NFRM is an alternative to the current DRBC and SRBC methods and establishes a passby flow designed to avoid significant adverse environmental impacts from withdrawals for high-volume hydraulic fracturing; specifically impacts associated with: degradation of a stream's best use and reduced stream flow including impacts to aquatic habitat and aquatic ecosystems. The Department proposes to require the NFRM as a permit condition and mitigation measure to ensure that water withdrawals, including those from the Delaware and Susquehanna River basins, in connection with high-volume hydraulic fracturing do not result in any significant adverse environmental impacts.

To assure adequate surface water flow when water withdrawals are made, provisions would be required to be made to provide for a passby flow in the stream, as defined above. In general, when streamflow data exist for the proposed withdrawal location, the passby flow is calculated for each month of the year using monthly flow exceedance values. Monthly flow exceedance value describes the percentage probability that the calculated streamflow statistic will be exceeded at any time during the month. For example, the Q60 monthly flow exceedance value is the calculated instantaneous flow that will be exceeded 60% of the time during a specific month. As described below, appropriate flow exceedance values will vary by month and will depend on the watershed size upstream from the water withdrawal.

The purpose of the NFRM is to provide seasonally adjusted instream flows that maintain the natural formative processes of the stream while requiring only minimal to moderate effort to calculate. Once adequate streamflow records are obtained, flow exceedance values are easily calculated. The foundation of the NFRM is based on the New England Aquatic Baseflow Standard.[20] Commonly referred to as the ABF, or New England Flow Policy, this method is a component of the broader U.S. Fish and Wildlife Service's New England Flow Policy. The basic assumption of the method is that varying flows based on monthly flow exceedance values are appropriate for maintaining differing levels of habitat quality within the stream and that the time periods for providing different levels of flow are appropriate based on life stage needs of the aquatic biota. Natural hydrologic variability is used as a surrogate for biological, habitat, and use parameters including: depth, width, velocity, substrate, side channels, bars and islands, cover, migration, temperature, invertebrates, fishing and floating, and aesthetics.

The objective of the NFRM is to retain naturalized annual stream flow patterns (hydrographs) and otherwise, avoid non-naturalized flows that may degrade stream conditions and result in adverse impacts.[21] Native aquatic species possess life history traits that enable individuals to survive and reproduce within a certain range of environmental variation. Changes in channel morphology and aquatic habitat that exceed this range of variation will result in community shifts that are detrimental to the native aquatic ecosystem. 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. Fluvial processes maintain a dynamic mosaic of aquatic habitat structures which create environmental factors that sustain diverse biotic assemblage; therefore, maintaining a natural flow regime is recognized as a primary driving force within riverine ecosystems. The survival of native species and natural communities is reduced if environment flows are pushed outside the range of their natural variability due to the resultant shifts in community structure. The NFRM manages our natural aquatic resources within their range of natural variability that maintains diverse, resilient, productive, and healthy ecosystems. The result is that passby flows calculated under this method emulate the natural hydrograph, including flushing flows that

[20] Larsen, 1981.

[21] IFC, 2004.

define and maintain the stream habitat suitable for aquatic biota. Research by Estes[22] and Reiser et al.[23] supports the need for these channel-maintaining flows.

There are limitations associated with the NFRM that must be considered, as it assumes a relationship to the stream biology. Data on historic stream flows must be of a sufficient duration and quality to represent the natural flow regimes of the stream[24] as prescriptions for passby flows are only as good as the hydrologic records on which they are based. Beyond concerns over the quality of available hydrologic data, data that are not based on natural flow conditions (e.g., releases from dams) will influence the calculation of passby flows and may not support fishery management objectives.

A. PASSBY FLOW METHODOLOGY: GENERAL CASE

Watersheds and associated waterways each have distinctive natural flow patterns with variable magnitude, duration, timing, and rate of change of flow rates and water levels. The NFRM preserves the inherent intra-annual variability associated with a natural flow pattern through the use of Q75 and/or Q60 monthly exceedance values for establishing passby flows as described below. The specific flow exceedance values of Q75 and Q60 were selected by Department staff using best professional judgment, based on research conducted by the State of Michigan (Zorn et al. 2008). The scientific framework for the Michigan work is the relationship between streamflow reductions and projected impact on resident fish populations. Regulatory decisions in Michigan regarding surface or groundwater withdrawals are designed to avoid an adverse resource impact to local stream ecosystems. Although Michigan methods vary from those described here, Michigan's requirements equate to flow exceedance values of approximately Q75 and Q60.

Waterways with substantial artificial alteration of stream flow by dams, weirs, bypasses, diversions, and water withdrawals or augmentation are different from waterways without manmade modifications to flow. As such, methods for determining appropriate passby flows are different for water bodies with "altered flow" and for water bodies with "natural flow." The

[22] Estes, 1984.

[23] Reiser, et al., 1988.

[24] Estes, 1998.

instream flow requirements would be calculated in accordance with the methods described in the following sections depending on whether the flow is natural or altered, and gaged or ungaged.

1. Waterways with "Natural Flow"

Waterways that are not subject to substantial artificial modification of stream flow by dams, weirs, bypasses, diversions, and water withdrawals or augmentation would be considered to have "natural flow". The method for computing the passby flows at a specific project site depends on whether the project is located on a gaged or an ungaged waterway, as described below.

Gaged Waterways - If the proposed water withdrawal project location is on a waterway with a USGS streamflow gage, and if the project site's drainage area is between 50 and 200% of the drainage area of the stream at the reference gage, a weighted flow exceedance estimate for the project site can be computed by using the drainage area ratio method. Streamflow statistics for a given month are estimated by:

$$Q_p = (A_p/A_g) \times Q_g$$

where Q_p is the flow exceedance value at the project site, Q_g is the flow exceedance value at the reference stream gage, A_p is the drainage area above the project site, and A_g is the drainage area above the reference stream gage. This equation assumes that the streamflow per unit area at the project site and reference gage are equal for any given month. Watershed drainage areas can be determined using the USGS StreamStats tool accessible at http://water.usgs.gov/osw/streamstats/ssonline.html.

Passby flows in gaged waterways with natural flow would be maintained such that:

a. when the watershed drainage area upstream from the water withdrawal location is greater than 50 square miles, the monthly passby flows would equal the monthly Q75 flow for the months of October through June and Q60 for the months of July through September; or

b. when the watershed drainage area upstream from the water withdrawal location is less than 50 square miles, the monthly passby flows would equal the monthly Q60 flow.

If the proposed water withdrawal project site is on a gaged stream but the site's drainage area is not between 50 and 200% of the drainage area of the stream at the gage, the passby flow should use the higher of the exceedance value estimates determined from either the reference gage in the watershed or the regional regression equation for ungaged waterways described below.

Ungaged Waterways - If the proposed water withdrawal project site is on a waterway that does not have an acceptable USGS streamflow gage as described above, passby flows can be determined using a regression analysis described in Department guidance documents.[25,26] Regression equations for estimating monthly flow exceedance values based on watershed areas have been established for six hydrologic regions across New York State (Figure 7.1).[27] Monthly passby flows, in cubic feet per second (cfs), can be calculated for project sites on ungaged waterways by multiplying the upstream drainage area by the appropriate regional coefficient from Table 7.2, below. These coefficients reflect the same principles described in paragraphs 1.a and b, directly above. If the upstream drainage area lies entirely within a single hydrologic region, the calculation is straightforward. If, however, the drainage area extends into multiple hydrologic regions, flows would be calculated based on the percentage that lies within each hydrologic region. The resulting passby flow is the weighted sum of the values derived from each hydrologic region within the entire upstream drainage area.

[25] DFWMR 2010.

[26] DFWMR 2010.

[27] Lumia et al. 2006.

Figure 7.1 - Hydrologic Regions of New York (New July 2011)
(Taken from Lumia et al, 2006)

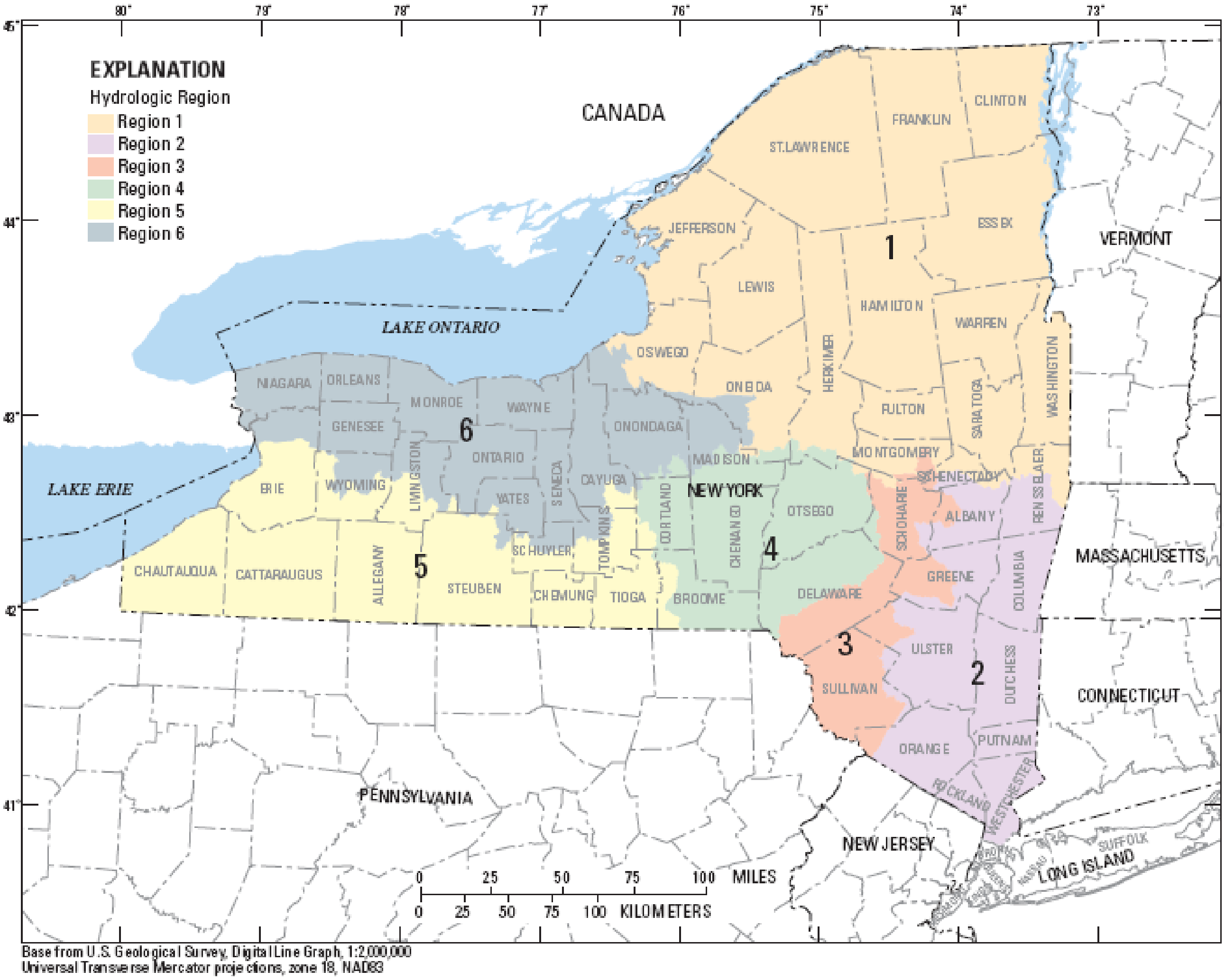

Table 7.2 - Regional Passby Flow Coefficients (cfs/sq. mi.) (Updated August 2011)

REGION	Drainage Area (mi²)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Adirondack	< 50 mi²	1.17	1.02	1.54	3.19	1.75	0.99	0.64	0.48	0.47	0.83	1.36	1.32
	> 50 mi²	0.97	0.86	1.19	2.57	1.39	0.76	0.64	0.48	0.47	0.64	1.07	1.09
Lower Hudson	< 50 mi²	1.30	1.27	1.97	1.99	1.21	0.62	0.36	0.24	0.20	0.41	0.89	1.48
	> 50 mi²	0.97	0.90	1.57	1.58	0.94	0.47	0.36	0.24	0.20	0.25	0.64	1.09
Catskill	< 50 mi²	1.23	1.07	1.93	2.57	1.48	0.77	0.44	0.28	0.32	0.61	1.51	1.63
	> 50 mi²	0.93	0.81	1.37	2.04	1.15	0.56	0.44	0.28	0.32	0.40	0.94	1.21
Susquehanna	< 50 mi²	1.23	1.11	1.94	2.28	1.09	0.55	0.35	0.23	0.22	0.39	1.00	1.49
	> 50 mi²	0.94	0.84	1.49	1.85	0.81	0.42	0.35	0.23	0.22	0.27	0.64	1.15
Southern Tier	< 50 mi²	1.02	0.92	1.77	2.07	0.85	0.42	0.29	0.21	0.20	0.40	0.85	1.33
	> 50 mi²	0.66	0.50	1.34	1.49	0.67	0.32	0.29	0.21	0.20	0.28	0.44	0.99
Lake Plains	< 50 mi²	0.93	1.00	1.66	1.46	0.69	0.34	0.22	0.17	0.17	0.25	0.52	1.01
	> 50 mi²	0.68	0.75	1.20	1.13	0.55	0.28	0.22	0.17	0.17	0.18	0.31	0.69

The passby flow requirement described above, if imposed via permit condition and/or regulation, would fully mitigate any potential significant adverse impact from water withdrawals associated with high-volume hydraulic fracturing in “Natural Flow” waterways.

2. Waterways with “Altered Flow”

Waterways would be considered to have “altered flow” if more than 25 % of the drainage area above a proposed project is upstream of a dam, weir, bypass, diversion, or other controlled artificial flow modification.[3] Watershed drainage areas can be determined using the USGS StreamStats tool accessible at http://water.usgs.gov/osw/streamstats/ssonline.html. Passby flows within altered waterways would be determined on a case-by-case basis using Department staff’s best professional judgment. Wherever possible, passby flows in altered waterways will provide flow patterns that emulate the annual flow hydrograph that would occur in the absence of all artificial flow alterations. The passby flow requirement, if imposed via permit condition and/or regulation, would fully mitigate any potential significant adverse impact from water withdrawals associated with high-volume hydraulic fracturing in “Altered Flow” waterways.

B. ALTERNATIVE PASSBY FLOWS

Alternative passby flows for water withdrawals associated with high-volume hydraulic fracturing that differ from those determined using the methodology described above may be approved on a case-by-case basis to protect endangered or threatened species in accordance with 6 NYCRR Part 182.

Protecting Other Surface Waters

As previously discussed in Chapter 6, water withdrawals from surface water bodies can have a direct impact upon aquatic habitats and other water users by the reduction of water volumes and levels. Smaller water bodies will see the greatest visible impact but even small level changes to large water bodies can sometimes be detrimental. A "safe or dependable" yield analysis is typically conducted for public water supplies to ensure the availability of water during extended drought conditions while also considering potential environmental impacts. Parameters such as stream inflow, usable storage volume, existing withdrawals, evaporation and precipitation amounts during prolonged drought periods arc used to calculate the amount of water that can be expected to be available for additional withdrawals. This same methodology can be applied to all types of withdrawals, including those to be used for hydraulic fracturing purposes. The key difference between public water supply and withdrawals for hydraulic fracturing is timing. Public water supplies typically require that a source be available at all times while other uses such as hydraulic fracturing may have the flexibility to limit their water withdrawals to times when surplus water is available.

Evaluation of Withdrawals from Surface Water Bodies

All withdrawals from surface water bodies will be evaluated to determine the impacts upon water quantity and level changes during extended drought conditions. The Department intends to require permittees to evaluate surface water bodies using the following equation:

$$\Delta V = I + P - W - E - R$$

Where ΔV = maximum change in storage, I = inflow into water body, P = precipitation onto water surface, W = existing and proposed water withdrawals, E = evaporation from water surface, and R = releases from water body. In some cases such as ponds, factors such as R may equal zero. The resulting maximum change in storage value (ΔV) shall be used to compute corresponding maximum water-level drawdowns. Site-specific SEQRA reviews should be conducted for withdrawals from ponds and lakes. Acceptable drawdown levels will be determined by Department on a case by case basis.

In accordance with the Department's Pump Test Recommendations, wetlands located within 500 feet of a proposed water withdrawal require monitoring during the pump test. Lowering of groundwater levels at or below a wetland is considered to be a significant impact.

7.1.1.5 Impact Mitigation Measures for Groundwater Withdrawals

The Department's DOW Recommended Pump Test Procedures for Water Supply Applications (http://www.dcc.ny.gov/lands/5003.html) will be used to evaluate proposed groundwater withdrawals for high-volume hydraulic fracturing.

As stated in the testing guidance, test results will be analyzed to evaluate:

- Impacts on neighboring water supplies

  Neighboring water supplies could be impacted if pumping of wells for Marcellus drilling requirements results in significant drawdown at offsite supplies. Site specific SEQRA reviews should be conducted for withdrawals from groundwater within 500 feet of private wells.

- Affects to the local groundwater basin

  The local groundwater basin can be similarly impacted resulting in lowering of groundwater levels. The range of impacts could vary from a lowering of water levels to a lowering of water levels to below pump intakes or to complete dewatering of wells.

- Impact on wetlands

  Impacts to water levels in wetlands could result in degradation of habitat. Site-specific SEQRA reviews should be conducted for withdrawals within 500 feet of wetlands if pump test results show the withdrawal could have an influence on the wetland.

- Well Capability

  Test results will establish the maximum pumping rate of the well independent of impacts.

- Surface water impacts (passby flows)

  Passby flows are required to:

  - protect aquatic resources,
  - protect competing users,
  - protect instream flow uses,
  - limit adverse lowering of streamflow levels downstream of the point of withdrawal.

The Department proposes to impose requirements regarding passby flows as stated in this document. With those mitigation measures in place there would be no significant adverse impacts from water withdrawals made in connection with high-volume hydraulic fracturing and associated horizontal drilling.

7.1.1.6 Cumulative Water Withdrawal Impacts

The SRBC (February, 2009) stated that "the cumulative impact of consumptive use by this new activity (natural gas development), while significant, appears to be manageable with the mitigation standards currently in place." The extent of the gas-producing shales in New York extends beyond the jurisdictional boundaries of the SRBC and the DRBC. New York State regulations do not currently address water quantity issues in a manner consistent with those applicable within the Susquehanna and Delaware River Basins with respect to controlling, evaluating, and monitoring surface water and ground water withdrawals for shale gas development. The application of the NFRM to all water withdrawals to support the subject hydraulic fracturing operations would comprehensively address cumulative impacts on stream flows because it will ensure a specified minimum passby flow, regardless of the number of water withdrawals taking place at one time. Accordingly, significant adverse cumulative impacts would be addressed by the NFRM described above because each operator of a permitted surface water withdrawal would be required, via permit condition and/or regulation, to estimate or report the maximum withdrawal rate and measure the actual passby flow for any period of withdrawal.

7.1.2 Stormwater

The principal control mechanism to mitigate potential significant adverse impacts from stormwater runoff is to require the development, implementation and maintenance of Comprehensive SWPPPs. SWPPPs address the often significant impacts of erosion, sedimentation, peak flow increase, contaminated discharge and nutrient pollution that is associated with industrial activity, including construction of well pads that would be required for high-volume hydraulic fracturing. This is commonly required through the administration of the Department's SPDES permits (individual or general) for stormwater runoff, which require operators to develop, implement and maintain up-to-date SWPPPs. To assist this effort, the Department has produced technical criteria for the planning, construction, operation and maintenance of stormwater control practices and procedures, including temporary, permanent, structural and non-structural measures. A successful Comprehensive SWPPP employs engineering concepts aimed at preventing erosion and maintaining post-development runoff characteristics in roughly the same manner as the pre-development condition. Many adverse impacts can be avoided by planning a development to fit site characteristics, like avoiding steep slopes and maintaining sufficient separation from environmentally sensitive features, such as streams and wetlands. Another basic principle is to divert uncontaminated water away from excavated or disturbed areas. In addition, limiting the amount of soil exposed at any one time, stabilizing disturbed areas as soon as possible, and following equipment maintenance, rapid spill cleanup and other basic good housekeeping measures will act to minimize potential impacts. Lastly, measures to treat stormwater and control runoff rates are described in the SWPPP.

A Comprehensive SWPPP that is well developed, implemented, maintained and adapted to changing circumstances in strict compliance with the Department's permit conditions and associated technical standards should effectively act to heighten the beneficial aspects of stormwater runoff while minimizing its potential deleterious impacts.

The Department has determined that natural gas well development using high-volume hydraulic fracturing would require a SPDES permit to address stormwater runoff, erosion and sedimentation. The SPDES permit will address both the construction of well pads and access roads and any associated soil disturbance, as well as provisions to address surface activities associated with high-volume hydraulic fracturing for natural gas development. Additionally, during the production of natural gas, the Department will require coverage under the SPDES permit to remain in effect and/or compliance with regulations. The Department proposes to require SPDES permit conditions, a Comprehensive SWPPP, and both structural and non-structural Best Management Practices (BMPs) to minimize or eliminate pollutants in stormwater. The Department is proposing the use of a SPDES general permit for high-volume hydraulic fracturing (HVHF GP), but the Department proposes to use the same requirements in other SPDES permits should the HVHF GP not be issued. The Department proposes to publish the proposed HVHF GP for public review and comment simultaneously with the formal public comment period on this document. A summary of the SPDES permit conditions follows.

Activities which are exposed to stormwater which will potentially take place during the development of a well pad may include:

- Well Drilling and Hydraulic Fracturing;
- Vehicle and Equipment Storage/Maintenance;
- Vehicle and Equipment Cleaning;
- Fueling;
- Material and Chemical Storage;
- Chemical Mixing, Material Handling, Loading/Unloading;
- Fuel/Chemical Storage Areas;
- Lumber Storage or Processing; and
- Cement Mixing.

Proposed required BMPs include, but not limited to, a combination of some or all of the following, or other equally protective practices:

- Identification of a spill response team and employee training on proper spill prevention and response techniques;
- Inspection and preventive maintenance protocols for the tank(s) and fueling area;
- Procedures for notifying appropriate authorities in the event of a spill or significant pit failure;
- Procedures for immediately stopping the source of the spill and containing the liquid until cleanup is complete;
- Ready availability of appropriate spill containment and clean-up materials and equipment, including oil-containment booms and absorbent material;
- Disposal of cleanup materials in the same manner as the spilled material;
- Use of dry cleanup methods and non-use of emulsifiers or dispersants;
- Protocols for checking/testing stormwater in containment area prior to discharge;
- Conducting tank filling operations under a roof or canopy where possible, with the covering extending beyond the spill containment pad to prevent rain from entering;
- Use of drip pans where leaks or spills could occur during tank filling operations and where making and breaking hose connections;
- Use of fueling hoses with check valves to prevent hose drainage after spilling;
- Use of spill and overflow protection devices;
- Use of diversion dikes, berms, curbing, grading or other equivalent measures to minimize or eliminate run-on into tank filling areas;
- Use of curbing or posts around the fuel tank to prevent collisions during vehicle ingress and egress;
- Availability of a manual shutoff valve on the fueling vehicle;
- Inspection and preventive maintenance protocols for the pit walls and liner;
- Procedures for immediately repairing the pit or liner and containing any released liquid until cleanup is complete;

- Location of additive containers and transport, mixing and pumping equipment as follows:
  - within secondary containment;
  - away from high traffic areas;
  - as far as is practical from surface waters;
  - not in contact with soil or standing water; and
  - product and hazard labels not exposed to weathering.
- Inspection and preventative maintenance protocols for containers, pumping systems and piping systems, including manned monitoring points during additive transfer, mixing and pumping activities;
- Protocols for ensuring that incompatible materials such as acids and bases are not held within the same containment area;
- Maintenance of a running inventory of additive products present and used on-site;
- Use of drip pads or pans where additives and fracturing fluid are transferred from containers to the blending unit, from the blending unit to the pumping equipment and from the pumping equipment to the well;
- Location of tanks within secondary containment, away from high traffic areas and as far as is practical from surface waters; and
- Maintenance of a running inventory of flowback water and produced water recovered, present on site, and removed from the site.

As discussed below, the Department is proposing a method to terminate the application of the SPDES permit upon Partial Site Reclamation in the manner presented in the HVHF GP or otherwise by the Department. With the proposed SPDES permit conditions in place for construction activities and high-volume hydraulic fracturing, as well as permit conditions and/or regulations for gas production, any potential significant adverse impacts from stormwater discharges associated with high-volume hydraulic fracturing would be adequately mitigated for most locations.

7.1.2.1 Construction Activities

In order to facilitate the SPDES permitting process for activities addressed by this Supplement, the Department proposes to utilize the requirements in the SPDES General Permit for Stormwater Discharges from Construction Activities, GP-0-10-001 (Construction General Permit), effective January 29, 2010. A Construction SWPPP, meeting or exceeding the requirements of the Construction General Permit, would be required to be developed as a stand-alone document, but will also constitute part of the Comprehensive SWPPP. The Construction SWPPP would address all phases and elements of the construction activity, including all land clearing and access road and well pad construction. The Construction SWPPP would be required to be prepared in accordance with good engineering practices and Department's Construction General Permit.

A copy of the Construction SWPPP would be required to be kept on site and available to Department inspectors while SPDES permit coverage is in effect. Particular monitoring, inspections and recordkeeping requirements associated with the construction activity will be initiated upon commencement of construction activities and continue until completion of the construction project.

7.1.2.2 Industrial Activities

The SPDES permit will require development of a high-volume hydraulic fracturing SWPPP that will be a stand-alone document, but will also constitute part of the Comprehensive SWPPP. The high-volume hydraulic fracturing SWPPP would address potential sources of pollution which may reasonably be expected to affect the quality of stormwater discharges associated with high-volume hydraulic fracturing operations. The Department will require implementation of BMPs that are to be used to reduce the pollutants in stormwater discharges associated with high-volume hydraulic fracturing and to ensure compliance with the terms and conditions of the SPDES permit. Structural, non-structural and other BMPs would have to be considered in the high-volume hydraulic fracturing SWPPP. Structural BMPs include features such as dikes, swales, diversions, drains, traps, silt fences and vegetative buffers. Non-structural BMPs include good housekeeping, sheltering activities to minimize exposure to precipitation to the extent practicable, preventative maintenance, spill prevention and response procedures, routine facility inspections, employee training and use of designated vehicle and equipment storage or maintenance areas with adequate stormwater controls. Particular monitoring, inspections and recordkeeping associated with high-volume hydraulic fracturing would be initiated upon completion of the construction project and continue until coverage under the SPDES permit has been appropriately terminated. Monitoring, inspections and reporting for high-volume hydraulic fracturing will address visual monitoring, dry weather flow inspections, and benchmark monitoring and analysis. Sites active for less than one year would be required to satisfy all annual reporting requirements within the period of activity.

The proposed high-volume hydraulic fracturing SWPPP will apply during all hydraulic fracturing and flowback operations at a well pad and until such time as coverage under the HVHF GP is appropriately terminated. A copy of the high-volume hydraulic fracturing SWPPP must be kept on site and available to Department inspectors while SPDES permit coverage is in effect. SPDES permit coverage may be terminated upon completion of all drilling and hydraulic fracturing operations, fracturing flowback operations and partial site reclamation in a manner specified by the Department. Partial site reclamation has occurred when a Department inspector determines that drilling and fracturing equipment have been removed, the pit or pits used for those operations have been reclaimed, and surface disturbances or surface parking or storage structures not necessary for production activities have been re-graded and seeded, vegetation cover re-established, and post-construction management practices are fully operational. Operators may, however, elect to maintain coverage under the SPDES permit after partial site reclamation if they so choose.

7.1.2.3 Production Activities

As part of a permit and/or in regulation, the Department proposes to require the owner/operator of the high-volume hydraulic fracturing operation to address potential sources of pollution which may reasonably be expected to affect the quality of stormwater discharges associated with the production phase. The Department will require implementation of BMPs that are to be used to reduce the pollutants in stormwater discharges associated with the production of gas resulting from high-volume hydraulic fracturing and to ensure compliance with the terms and conditions of the appropriate permit and/or regulation. Structural, nonstructural and other BMPs will be incorporated into a permit and/or regulation.

Particular monitoring, inspections and recordkeeping associated with the high-volume hydraulic fracturing will be include in the permit and/or regulation and initiated once coverage under the SPDES permit has been appropriately terminated.

7.1.3 Surface Spills and Releases at the Well Pad

A combination of existing Department engineering controls and management practices, enhanced as necessary to address unique aspects of multi-well pad development and high-volume hydraulic fracturing, would be required in appropriate permits to prevent spills and mitigate adverse impacts from any that do occur. This would include disclosure to the Department of fracturing fluid constituents, so that the appropriate remediation measures can be taken if a spill occurs. Activities and materials on the well pad of concern with respect to potential surface and groundwater impacts from unmitigated spills and releases include the following:

- fueling tank and tank refilling activities;
- drilling fluids;
- hydraulic fracturing additives and flowback water;
- production brine;
- materials and chemical storage;
- chemical mixing, material handling, loading/unloading areas;
- bulk chemical/fluid storage tanks;
- equipment cleaning;
- on-site waste storage or disposal;
- vehicle and equipment storage/maintenance areas;
- piping/conveyances;
- lumber storage and/or processing areas; and
- cement mixing/concrete products manufacturing.

The proposed spill prevention and mitigation measures advanced herein reflect consideration of the following information reviewed by Department staff:

- The 1992 GEIS and its Findings;
- GWPC, 2009b;
- Alpha, 2009, regarding:
    - a survey of regulations related to natural gas development activities in Pennsylvania, Colorado, New Mexico, Wyoming , Texas (including the City of Fort Worth), West Virginia, Louisiana, Ohio and Arkansas;
    - materials handling and transport requirements, including USDOT and NYSDOT regulations, the Department's Bulk Storage Programs and EPA reporting requirements; and
    - specific recommendations for minimizing potential liquid chemical spills;
- Guidance documents relative to the Department's Petroleum Bulk Storage Program, including:
    - Spill Prevention Operations Technology Series (SPOTS) 10, Secondary Containment Systems for Aboveground Storage Tanks;[28] and
    - Draft Department Program Policy DER-17.[29]
- SWPPP guidance compiled by the Department's Division of Water; The comprehensive Stormwater Pollution Prevent Plan (SWPPP) that would be required by the Department's proposed HVHF GP will include permit requirements for Good Housekeeping Procedures, Spill Reduction Measures and Structural Best Management Practices to minimize or eliminate pollutants in stormwater for all of the activities listed above;
- US Department of the Interior and US Department of Agriculture, 2007; and
- An industry BMP manual provided to the Department.

7.1.3.1 Fueling Tank and Tank Refilling Activities

The diesel tank fueling storage associated with the larger rigs described in Chapter 5 may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the

[28] http://www.dec.ny.gov/docs/remediation_hudson_pdf/spots10.pdf.

[29] http://www.dec.ny.gov/docs/remediation_hudson_pdf/der17.pdf.

length of time required to drill all of the wells on the pad. However, the tank would be removed along with the rig during any drilling hiatus between wells or after all the wells have been drilled. There are no long-term or permanent operations at a drill pad which require an on-site fueling tank. Therefore, the tank is considered non-stationary and is exempt from the Department's petroleum bulk storage regulations and tank registration requirements. The following measures are proposed to be required, via permit condition and/or regulation, to prevent and mitigate spills. For all wells subject to the SGEIS, supplementary permit conditions for high-volume hydraulic fracturing would include the following requirements with respect to fueling tanks and refilling activities:

a. Secondary containment consistent with the objectives of SPOTS 10 for all fueling tanks.

   The secondary containment system could include one or a combination of the following: dikes, liners, pads, holding ponds, curbs, ditches, sumps, receiving tanks or other equipment capable of containing spilled fuel. Soil that is used for secondary containment would be of such character that a spill into the soil will be readily recoverable and would result in a minimal amount of soil contamination and infiltration. Draft Department Program Policy DER-17[30] may be consulted for permeability criteria for dikes and dike construction standards, including capacity of at least 110% of the tank's volume.

   Implementation of secondary containment and permeability criteria is consistent with GWPC's recommendations;

b. Fueling tanks would not be positioned within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond;

c. Fueling tank filling operations would be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

d. Troughs, drip pads or drip pans would be required beneath the fill port of the fueling tank during filling operations if the fill port is not within the secondary containment.

[30] http://www.dec.ny.gov/docs/remediation_hudson_pdf/der17.pdf.

7.1.3.2 Drilling Fluids

The 1992 GEIS describes reserve pits excavated at the well which may contain drill cuttings, drilling fluid, formation water, and flowback water from a single well. As stated in the 1992 GEIS:

> Although the existing regulations do mention clay and hardpan as options in pit construction, the Department has consistently required that all earthen temporary drilling pits be lined with sheets of plastic before they can be used. Clay and hardpan are both low in permeability, but they are not watertight. They are also subject to chemical reaction with some drilling and completion fluids. In addition, the time constraints on drilling operations do not allow adequate time for the percolation tests which should be performed to check the permeability of a clay lined pit. Liners for large pits are usually made from several sheets of plastic which should be factory seamed. Careful attention to sealing the seams is extremely important in preventing groundwater contamination; [31]*and:*
>
> Pits for fluids used in the drilling, completion, and re-completion of wells should be constructed, maintained and lined to prevent pollution of surface and subsurface waters and to prevent pit fluids from contacting surface soils or ground water zones. Department field inspectors are of the opinion that adequate maintenance after pit liner installation is more critical to halting pollution than the initial pit liner specifications. Damaged liners must be repaired or replaced promptly. Instead of very detailed requirements in the regulations, the regulatory and enforcement emphasis will be on a general performance standard for initial review of liner-type and on proper liner maintenance.
>
> The type and specifications of the liner proposed by the well drilling applicant will require approval by the DEC Regional Minerals Manager. The acceptability of each proposed pit construction and location should be determined during the pre-site inspection. Any pit site or pit orientation found unacceptable to the Department must be changed as directed by the regional site inspector.[32]

Existing regulations require that pit fluids must be removed within 45 days of cessation of drilling operations (includes stimulation), "unless the department approves an extension based on circumstances beyond the operator's control. The department may also approve an extension if the fluid is to be used in subsequent operations according to the submitted plan, and the department has inspected and approved the storage facilities."[33]

[31] NYSDEC 1992, GEIS, p. 9-32.

[32] NYSDEC, 1992, GEIS p. FGEIS48.

[33] 6 NYCRR §554.(1)(c)(3).

Within primary and principal aquifers, existing permit conditions require that if operations are suspended and the site is left unattended, pit fluids must be removed from the site immediately.[34] After the cessation of drilling and/or stimulation operations, pit fluids must be removed within seven days.

Recommended 1992 GEIS specifications, and the ultimate decision to use a site and performance-based standard rather than detailed specifications, were largely based upon the short duration of a pit's use. Pits used for more than one well, as would be the case for high-volume hydraulic fracturing, would be used for a longer period of time. "The containment of fluids within a pit is the most critical element in the prevention of shallow ground water contamination."[35] Specifications more stringent than those proposed in the 1992 GEIS which relate to durability and longer duration of use are appropriate, and are consistent with GWPC's recommendations (Section 5.18.1.2). Additional protection would be provided by the requirement for a SWPPP and by measuring proposed setbacks from the edge of the well pad instead of from the well.

The following measures are proposed to be required to mitigate the potential for releases associated with any on-site reserve pit:

1) The EAF Addendum would require information about the planned location, construction and capacity of the reserve pit. The Department would not approve reserve pits on the filled portion of cut-and-fill sites; and

2) Supplementary permit conditions for multi-well pad high-volume hydraulic fracturing would include the following requirements:

    a. Diversion of surface water and stormwater runoff away from the pit;

    b. Flowback water would be prohibited from being directed to or stored in any on-site pit;

    c. Pit volume limit of 250,000 gallons, or 500,000 gallons for multiple pits on one tract or related tracts of land;

[34] Freshwater Aquifer Supplementary Permit Conditions, www.dec.ny.gov/energy/42714.html.

[35] GWPC, 2009 April, p. 29.

d. Beveled walls (45 degrees or less) for pits constructed in unconsolidated materials;

e. Sidewalls and bottoms free of objects capable of puncturing and ripping the liner;

f. Sufficient slack in liner to accommodate stretching;

g. Minimum 30-mil liner thickness;

h. Liners installed and seamed in accordance with the manufacturer's specifications, and constructed, coated, or lined with materials that are chemically compatible with the substance (s) stored and the environment;

i. Freeboard monitoring and maintenance of 2 feet of freeboard at all times (except freshwater);

j. Fluids removed and pit inspected by a Department inspector prior to additional use if longer than a 45-day gap in use; and

k. Fluids removed and pit reclaimed within 45 days of completing drilling and stimulation operations at last well on pad.

As discussed in Section 7.1.9, the Department proposes, via permit condition and/or regulation, that, reserve pits would not be utilized for on-site management of drilling fluids and the cuttings entrained with the fluids when the cuttings are required to be disposed of at an off-site facility. Under circumstances which require the off-site disposal of cuttings, both the cuttings and all associated drilling fluids would be required to be managed on-site within a closed-loop tank system.

Chapter 5 discusses the required use of the blow-out prevention (BOP) system and Chapter 6 includes potential impacts that could occur as a result of a component failure of the BOP system or if the system is improperly operated. The Department proposes to require, via permit condition and/or regulation, the following requirements:

1. Individual crew member's responsibilities for blowout control would be posted in the doghouse or other appropriate location and each crew member would be made aware of such responsibilities prior to spud of any well being drilled or when another rig is moved on a previously spudded well and/or prior to the commencement of any rig, snubbing unit or coiled tubing unit performing completion work. During all drilling and/or completion operations when a BOP is installed, tested or in use, the operator or operator's designated representative would be present at the wellsite and such person or personnel would have a

current well control certification from an accredited training program that is acceptable to the Department (e.g., International Association of Drilling Contractors). Such certification would be available at the wellsite and provided to the Department upon request;

2. Appropriate pressure control procedures and equipment in proper working order would be employed while conducting drilling and/or completion operations including tripping, logging, running casing into the well, and drilling out solid-core stage plugs. Unless otherwise approved by the Department, a snubbing unit and/or coiled tubing unit with a BOP would be used to enter any well with pressure and/or to drill out one or more solid-core stage plugs; and

3. Pressure testing of the blow-out preventer (BOP) and related equipment for any drilling and/or completion operation would be performed in accordance with the approved BOP use and test plan, and any deviation from the approved plan would be approved by the Department. Testing would be conducted in accordance with American Petroleum Institute (API) Recommended Practice (RP) 53, RP for Blowout Prevention Systems for Drilling Wells, or other procedures approved by the Department.

The aforementioned measures would adequately mitigate any significant adverse environmental impacts posed by drilling fluids associated with high-volume hydraulic fracturing.

7.1.3.3 Hydraulic Fracturing Additives

Chapter 5 describes the USDOT- or UN-approved containers in which hydraulic fracturing additives are delivered and held until they are mixed with water and proppant and pumped into the well, and also describes the length of time that additives are present on the site. Well pad setbacks from water resources described in Section 7.1.12 apply to all locations. Additional protection would be provided by the requirement to measure proposed setbacks from the edge of the well pad instead of from the wellbore. Additional mitigation measures would be implemented as follows to fully mitigate any potential significant adverse impacts from hydraulic fracturing additives:

1) Secondary containment would be required for all fracturing additive containers and additive staging areas. These requirements would be included in supplementary well permit conditions for high-volume hydraulic fracturing.

   Secondary containment measures may include one or a combination of the following; dikes, liners, pads, curbs, sumps, or other structures or equipment capable of containing the substance. Any such secondary containment would be required to be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area.

The Department proposes to require, via permit condition and/or regulation, 1) removal of hydraulic fracturing additives from the site if the site will be unattended and 2) at least two vacuum trucks would be on standby at the wellsite during the pumping of hydraulic fracturing fluid;

2) As described in Part 8.2.1.2, the operator's permit application materials would document its evaluation of alternative additive products that may pose less risk to the environment, including water resources; and

3) Required disclosure to the Department of fracturing fluid additives would ensure that the appropriate steps could be taken if a spill or release did occur. (See Chapter 8 for a discussion of the specific additive information which would be required.)

7.1.3.4 Flowback Water

The 1992 GEIS addresses use of the on-site reserve pit for flowback water associated with a single well. However, even in the single-well case, potential flowback water volumes associated with high-volume hydraulic fracturing exceed 1992 GEIS descriptions. Estimates provided in Section 5.11.1 are for 216,000 gallons to 2.7 million gallons of flowback water recovered within two to eight weeks of hydraulic fracturing a single well. The volume of flowback water that would require handling and containment on the site is variable and difficult to predict, and data regarding its likely composition are incomplete. Therefore, the Department proposes to require, via permit condition and/or regulation, that flowback water handled at the well pad be directed to and contained in covered watertight steel tanks or covered watertight tanks constructed of another material approved by the Department. Even without this requirement, the pit volume limitation proposed above would necessitate that tank storage be available on site. The Department will also continue to encourage exploration of technologies that promote reuse of flowback water when practical. Additional mitigation measures would be implemented as follows:

1) The EAF Addendum would require information about the number, individual and total capacity and location on the well pad of receiving tanks for flowback water;

2) Permit conditions for high-volume hydraulic fracturing would include the following requirements:

    a. Fluids would be removed if there will be a hiatus in site activity longer than 45 days;

b. Fluids would be removed within 45 days of completing drilling and stimulation operations at last well on pad;

c. Fluid transfer operations from tanks to tanker trucks would be manned at the truck and at the tank if the tank is not visible to the truck operator from the truck;

d. Secondary containment for flowback tanks is required; and

e. At least two vacuum trucks would be on standby at the wellsite during the flowback phase.

7.1.3.5 Primary and Principal Aquifers

Based on the analysis contained in Sections 6.1.3.4, the Department has determined that the activities associated with high-volume hydraulic fracturing pose a risk of causing significant adverse impacts to Primary Aquifers and, therefore, such operations may not be consistent with the long-term protection of Primary Aquifers. The Department finds that standard stormwater control and other mitigation measures may not fully mitigate the risk of potential significant adverse impacts on these water resources from spills or other releases that could occur in connection with high-volume hydraulic fracturing operations.

Therefore, the Department proposes to bar placement of high-volume hydraulic fracturing well pads over Primary Aquifers and an associated 500-foot buffer to provide an adequate margin of safety from the full range of high-volume hydraulic fracturing activities. As defined in TOGS 2.1.3, Primary Aquifers are currently extensively used by major municipalities as a source of drinking water. Contamination of a Primary Aquifer could render a large, concentrated population without drinking water. Replacing a drinking water source of this magnitude would be prohibitive because of exorbitant costs, difficulty in locating alternative water supply sources, and the extensive time needed to implement any alternatives. However, because the mitigation measures that would be imposed through permit conditions and/or regulations may prove effective for preventing uncontained, unmitigated releases that could contaminate Primary Aquifers, this bar will be re-evaluated two years after the commencement of issuance of well permits associated with high-volume hydraulic fracturing operations.

The Department further proposes to require a site-specific SEQRA review for placement of high-volume hydraulic fracturing well pads that are proposed to be located over Principal Aquifers or within a 500-foot buffer, as well as an individualized SPDES stormwater permit. As defined in TOGS 2.1.3 and explained in Chapters 2 and 6, Principal Aquifers are currently not intensively used by major municipalities as a source of drinking water, as compared to Primary Aquifers. However, contamination of a Principal Aquifer could still render a large population without water. Because mitigation measures that would be imposed through permit conditions and/or regulations may prove effective for preventing uncontained, unmitigated releases that could contaminate Principal Aquifers, this proposed requirement will be re-evaluated in two years after the commencement of issuance of well permits for high-volume hydraulic fracturing operations.

It is important to note that although the percentage of land in New York designated as a Primary and Principal Aquifer appears significant, due to the fact that wells can be drilled horizontally, well pads placed outside the boundary of a Primary and Principal Aquifer area may still allow for access to natural gas reserves underlying the significant majority of the area beneath Primary and Principal Aquifers. For example, assuming both a 500-foot buffer from the edge of a Primary and Principal Aquifer and the capacity to drill a 3,500-foot horizontal leg, and also assuming lease rights, surface access rights and lack of other siting restrictions, less than 1% of the area where the Marcellus Shale is deeper than 2,000 feet below ground surface and also beneath Primary or Principal Aquifers would be made at least potentially inaccessible for the extraction of natural gas by high-volume hydraulic fracturing.

Summary

To ensure that mitigation measures are sufficient to protect primary and principal aquifers, which are described in Chapters 2 and 6 of this Supplement and in the 1992 GEIS, the Department would implement the following restrictions until at least two years after issuance of the first permit for high-volume hydraulic fracturing:

1) No well pads would be approved within 500 feet of primary aquifers; and

2) A site-specific SEQRA review and determination of significance, and a site-specific SPDES permit, would be required for any proposed well pad within 500 feet of a principal aquifer.

Two years after issuance of the first permit for high-volume hydraulic fracturing, the Department would re-evaluate the need for these restrictions based on experience with high-volume hydraulic fracturing outside of these restricted areas.

7.1.4 Potential Ground Water Impacts Associated With Well Drilling and Construction

Existing construction and cementing practices and permit conditions to ensure the protection and isolation of fresh water would remain in use, and would be enhanced by Permit Conditions for high-volume hydraulic fracturing. See Appendices 8, 9 and 10. Based on discussion in Chapters 2 and 6 of this Supplement, along with GWPC's regulatory review,[36] the Department proposes to require the following measures associated with well drilling and construction in order to prevent potential groundwater impacts from these activities:

- Baseline water quality testing of private wells within a specified distance of the proposed well;
- Sufficiency of as-built wellbore construction prior to high-volume hydraulic fracturing, including:
    - Adequacy of surface casing to protect fresh water and to isolate potable fresh water supplies from deeper gas-bearing zones;
    - Adequacy of cement in the annular space around the surface casing;
    - Adequacy of cement in the annular space around the intermediate casing;
    - Adequacy of cement on production casing to prevent upward migration of fluids; including gas, during hydraulic fracturing and production conditions;
    - Use of centralizers to ensure that the cement sheath surrounds the casing strings, including the first joint of surface and intermediate casings; and
    - The opportunity for state regulators to witness cementing operations; and
- Prevention of pressure build-up at the surface casing seat and in the annular space between the surface casing and intermediate casing.

The proposed well construction-related requirements advanced herein reflect consideration of the following information and sources:

[36] GWPC, 2009 May.

- The 1992 GEIS and its Findings;

- The Department's existing required casing and cementing practices (Appendix 8);

- The Department's existing supplementary freshwater aquifer permit conditions (Appendix 9);

- Harrison, 1984, with respect to the importance of maintaining the surface-production casing annulus in a non-pressurized condition (a preventative measure which has been implemented as part of the Department's required casing and cementing practices since at least 1985);

- Commissioner's Decision, 1985, regarding well casing cement and the requirement to maintain an open annulus to prevent gas migration into aquifers;

- API, regarding:

    - Specification 5CT, Specifications for Casing and Tubing (April 2002);

    - Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);

    - RP 10D-2, RP for Centralizer Placement and Stop Collar Testing (August 2004);

    - Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum);

    - Guidance Document, HF1, Hydraulic Fracturing Operations - Well Construction and Integrity Guidelines (October 2009); and

    - RP 65 – Part 2, Isolating Potential Flow Zones During Well Construction (May 2010).

- Pennsylvania Environmental Quality Board, Title 25-Environmental Protection, Chapter 78, Oil and Gas Wells, Pennsylvania Bulletin, Vol. 41, No. 6 (February 5, 2011);

- Ohio Department of Natural Resources, 2008, regarding permit conditions developed to prevent over-pressurized conditions in the surface-production casing annulus;

- GWPC, 2009b, well construction recommendations;

- NYSDOH Recommended Residential Water Quality Testing, Individual Water Supply Wells Fact Sheet #3, relative to recommended water quality testing for all wells and recommended additional parameters to test if gas drilling nearby is the reason for water testing;[37]

- NYSDOH recommendations relative to private water well testing dated July 21, 2009, based on review of fracturing fluid constituents and flowback characteristics;

- URS, 2009, water well testing recommendations based on review of fracturing fluid constituents and flowback characteristics;

- Alpha, 2009, regarding:

  - water well testing requirements in other states identified through a survey of regulations in 10 other jurisdictions; and

  - previous drilling in aquifers, watersheds and aquifer recharge areas; and

- ICF, 2009a, regarding:

  - water well testing recommendations; and

  - review of hydraulic fracturing design and subsurface fluid mobility.

7.1.4.1 Private Water Well Testing

The Department proposes to require, via permit condition, that the operator, at its own expense, sample and test all residential water wells within 1,000 feet of the well pad, subject to the property owner's permission, or within 2,000 feet of the well pad if no wells are available for sampling within 1,000 feet either because there are none of record or because the property owner denies permission. The Department would require that results of each test be provided to the property owner within 30 days of the operator's receipt of laboratory results. The Department would further require that the data be available to the Department and local health department upon request for complaint investigation purposes.

Schedule

Testing before drilling is recommended as a mitigation measure related to the potential for groundwater contamination because it provides a baseline for comparison in the event that water contamination is suspected. Testing prior to drilling each well at a multi-well pad provides ongoing monitoring between drilling operations, so the requirement would be attached to every

[37] http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs3_water_quality.htm, accessed 9/16/09.

well permit that authorizes high-volume hydraulic fracturing. Testing at established intervals after drilling or hydraulic fracturing operations provides opportunities to detect contamination or confirm its absence. If no contamination is detected a year after the last hydraulic fracturing event on the pad, then further routine monitoring should not be necessary. The Department proposes to require, via permit condition the following ongoing monitoring schedule:

- Initial sampling and analysis prior to site disturbance at the first well on the pad, and prior to drilling commencement at additional wells on multi-well pads;
- Sampling and analysis three months after reaching total measured depth (TMD) at any well on the pad if there is a hiatus of longer than three months between reaching TMD and any other milestone on the well pad that would require sampling and analysis; and
- Sampling and analysis three months, six months and one year after hydraulic fracturing operations at each well on the pad.

For multi-well pads where drilling and hydraulic fracturing activity is continuous, to the extent that water well sampling and analysis according to the above schedule would occur more often than every three months, the Department proposes to simplify the protocol so that sampling and analysis occurs at three month intervals until six months after the last well on the pad is hydraulically fractured, with a final round of sampling and analysis one year after the last well on the pad is hydraulically fractured.

More frequent sampling and analysis, or sampling and analysis beyond one year after last hydraulic fracturing operations, may be warranted in response to complaints as described below or for other reasonable cause.

Parameters

The NYSDOH recommends testing for the analytes listed in Table 7.3 to aid with determining whether gas drilling may have had an impact on the quality or quantity of a well. This analysis is not intended to constitute a comprehensive evaluation. In the event that a potential impact is determined, additional investigation (e.g., isotopic analysis of methane to determine source or site-specific chemical analysis) may be necessary.

Table 7.3 - NYSDOH Water Well Testing Recommendations
(Revised July 2011to reflect more recent recommendations from NYSDOH)

Parameter	**Notes**
Barium	Barium (barite) is a principal component of many drilling muds. In the event that barite is not used in the drilling mud, a substitution should be made for a component that is present in the drilling mud.
Chloride	A measure of chloride anions in water. Chlorides and other salts are naturally occurring and can be found in many different geologic zones, but deep groundwater typically contains high levels of chloride. Flowback water contains high levels of chlorides. Therefore, an increase in chlorides may be an indication that drilling has allowed communication between geologic zones and/or flowback water has contaminated an aquifer.
Conductivity	A measure of the ability of water to pass an electrical current. Conductivity in water is affected by the presence of inorganic dissolved solids such as chloride, nitrate, sulfate, and phosphate anions (ions that carry a negative charge) or sodium, magnesium, calcium, iron and aluminum cations (ions that carry a positive charge). Organic compounds like oil, phenol, alcohol and sugar do not conduct electrical current very well and therefore have a low conductivity when in water. A change in water quality as a result of drilling is expected to affect the conductivity.
Gross alpha/beta	Radioactivity is typically elevated in shale relative to other rock types and the Marcellus Shale is especially enriched. Drilling and production of shale may have the ability to mobilize radioactivity towards the surface where it could either concentrate or infiltrate aquifers. These Gross analyses are screening values for defining when to perform more detailed analyses.
Iron	Iron is commonly found in many aquifers and may be mobilized during initial drilling activities.
Manganese	Manganese is commonly found in many deep and shallow aquifers and may be mobilized during initial drilling activities.
Dissolved methane & ethane	Occurs naturally in many aquifers but may also migrate into aquifers as a product of drilling and production. Additional analysis may be necessary to determine the source and/or percentages of dissolved gasses.
pH	A measure of how acidic or basic water is. pH is sensitive to small changes in water chemistry such as those that may result from natural gas drilling.
Sodium	Sodium is naturally occurring and commonly found in most water. However, sodium is found in high concentrations in deep shale production brines and gas wells.
Total dissolved solids (TDS)	A measure of all dissolved organic and inorganic species in water. TDS is useful as an indicator of aesthetic characteristics of drinking water and as an aggregate indicator of the presence of a broad array of chemical contaminants. An increase in TDS may be indicative of drilling operations having introduced contaminants into the water supply.
Static water level	Static water level is the level of the water in the well during normal conditions prior to any pumping. This is a measure of the amount of water in the aquifer. Analysis of changes in static water level should carefully consider the well's construction, maintenance and operational history, recent precipitation and use patterns, the season and the effects of competing wells.
Volatile organic compounds (VOCs), specifically BTEX	VOCs encompass a number of compounds that are expected to be used extensively during surface operations and would account for water supplies potentially being affected by spills, leaking pits, or other unforeseen incidents. Additionally, certain VOCs are known to exist in shale and are expected to be a contaminant of concern in the event that flowback waters or production brines migrate into an aquifer.

Sampling Protocol

The Department proposes to require that water samples to be collected by a qualified professional and analyzed utilizing a NYSDOH ELAP approved laboratory,[38] including the use of proper sampling and laboratory protocol, in addition to the use of proper sample containers, preservation methods, holding times, chain of custody, analytical methods, and laboratory QA/QC.

The water samples would be representative of the aquifer being produced by the well. Therefore, the well pump should be allowed to run for at least 5 minutes prior to sample collection. The sample should be collected prior to any in home water treatment that may be present. If this is not feasible, the type of treatment that is present on the well survey should be noted. The samples should be collected in appropriate containers, refrigerated, and transported to the laboratory for analysis.

Recommended Sampling Procedure for Water Supply Wells

- Select an indoor, leak-free, cold water faucet from which to collect the sample. If treatment (softener, filter, RO, etc) exists the sample should be collected from an untreated location or the treatment should be bypassed;
- Remove the faucet's aerator or strainer, if one is present;
- Disinfect the faucet by cleaning and flaming the inside of the faucet;
- Let cold water run for 5 minutes;
- Reduce water flow to a stream of water the size of a pencil or smaller;
- Fill sample bottles per method specifications, making sure not the touch the inside of the bottle or cap; and
- Cap bottles, refrigerate, and transport to the laboratory for analysis.

[38] http://www.wadsworth.org/labcert/elap/elap.html, accessed 9/16/09.

Complaints

As noted in the 1992 GEIS:

> The diversity of jurisdictions having authority over local water supplies complicates the response to complaints about water supplies, including those complaints that complainants believe are related to oil and gas activity. Water supply complaints occur statewide and take many forms, including taste and turbidity problems, water quantity problems, contamination by salt, gasoline and other chemicals and problems with natural gas in water wells. All of these problems, including natural gas in water supplies, occur statewide and are not restricted to areas with oil and gas development.[39] *and:*

> The initial response to water supply complaints is best handled by the appropriate local health office, which has expertise in dealing with water supply problems.[40]

The Department has MOUs in place with several county health departments in western NY whereby the county health department initially investigates a complaint and then refers it to the Department when a problem has been verified and other potential causes have been ruled out. For complaints that occur more than a year after the last hydraulic fracturing operations on a well pad within the radius where baseline sampling occurred (1,000 feet or 2,000 feet), or for complaints regarding water wells that are more than 2,000 feet away from any well pad, the Department proposes to continue following the aforementioned procedure statewide. Complaints would be referred to the county health department, who would refer them back to the Department for investigation when a problem has been verified and other potential causes have been ruled out. Sampling and analysis to verify and evaluate the problem would be according to protocols that are satisfactory to the county health department, with advice from NYSDOH as necessary.

Complaints that occur during active operations at a well pad within 2,000 feet or the radius where baseline sampling occurred, or within a year of last hydraulic fracturing at such a site, should be jointly investigated by the Department and the county health department. Mineral Resources staff would conduct a site inspection, and if a complaint coincides with any of the following documented potentially polluting non-routine well pad incidents, then the Department would consider the need to require immediate cessation of operations, immediate corrective

[39] NYSDEC, 1992, GEIS, pp. 15-4 et seq.

[40] NYSDEC, 1992, GEIS, p. 15-5.

action and/or revisions to subsequent plans and procedures on the same well pad, in addition to any applicable formal enforcement measures:

- Surface chemical spill;
- Fracturing equipment failure;
- Observed leaks in surface equipment onto the ground, into stormwater runoff or into a surface water body;
- Observed pit liner failure;
- Significant lost circulation or fresh water flow below surface casing;
- The presence of brine, gas or oil zones not anticipated in the pre-drilling prognosis;
- Evidence of a gas-cut cement job;
- Anomalous flow or pressure profile during fracturing operations;
- Any non-routine incident listed in ECL §23-0305(8)(h) (i.e., casing and drill pipe failures, casing cement failures, fishing jobs, fires, seepages, blowouts); or
- Any violation of the ECL, its implementing rules and regulations, or any permit condition, including the requirement that the annulus between the surface casing and the next casing string be maintained in a non-pressurized condition; and

The Department and the county health department would share information. All data on file with the county health department relative to the subject water well, including pre-existing conditions and any available information about the well's history of use and maintenance, would be considered in determining the proper course of action with respect to well pad activities. Sub-section 8.2.3 describes the Department's enforcement authority and the enforcement mechanisms available to the Department.

7.1.4.2 Sufficiency of As-Built Wellbore Construction

Wellbore construction is addressed by the existing 1992 GEIS. While the same concepts apply to wells used for high-volume hydraulic fracturing, some enhancements are proposed because of the high pressures that will be exerted, the large fluid volumes that will be pumped and potential concentration of the activity in areas without much subsurface well control. Further, recent

Marcellus Shale well drilling and completion experience and associated problems in other states were analyzed and considered.

Surface Casing

As defined in regulations, the purpose of surface casing is to protect potable fresh water.[41] For oil and gas regulatory purposes, potable fresh water is defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm of total dissolved solids.[42] As stated in Chapter 2, maximum depth of potable water in an area should be determined based on the best available data. This would include water wells and other oil and gas wells in the area, any available local or regional geologic or hydrogeologic reports, and information from the sources listed in Section 7.1.10.1. When information is not available, a depth of 850 feet to the base of potable groundwater is a commonly-used and practical generalization.

Current casing and cementing practices attached as conditions to all oil and gas permits require that:

- surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into bedrock, whichever is deeper, and deeply enough to allow the blow-out preventer stack to contain any formation pressures that may be encountered before the next casing is run;
- surface casing shall not extend into zones known to contain measurable quantities of shallow gas, and, in the event such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and take Department-approved actions to protect the fresh water zone(s); and
- surface casing shall consist of new pipe with a mill test of at least 1,000 psi, or used casing that is pressure tested before drilling ahead after cementing; welded pipe must also be pressure tested.

The Department proposes to require, via permit condition and/or regulation, the submission of a *Pre-Frac Checklist and Certification Form* (pre-frac form) to the Department at least 3 days prior to commencement of high-volume hydraulic fracturing operations. Regarding the surface casing hole, the pre-frac form would:

[41] 6 NYCRR §550.3(au).

[42] 6 NYCRR §550.3(ai).

a. attest to well construction having been performed in accordance with the well permit or approved revisions,

b. list the depth and estimated flow rates where fresh water, brine, oil and/or gas were encountered or circulation was lost during drilling operations, and

c. include information about how any lost circulation zones were addressed.

Hydraulic fracturing would not be authorized to proceed without the above information and certification.

Surface Casing Cement

Current casing and cementing practices attached as conditions to all oil and gas permits require:

- cementing by the pump and plug method and circulation to surface;
- minimum of 25% excess cement pumped, with appropriate lost circulation materials;
- testing of the mixing water for pH and temperature prior to mixing;
- cement slurry preparation to the manufacturer's or contractor's specifications to minimize free water in the cement; and
- no casing disturbance after cementing until the cement achieves a calculated compressive strength of 500 psi (e.g., performance chart).

All of the above requirements would remain in effect, and the Department would require the following additional requirements via permit condition and/or regulation:

1) The pre-frac form would be required as described above;

2) Cement would be required to conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry would be required to be prepared to minimize its free water content in accordance with the same API specification and it would be required to contain a gas-block additive; and

3) A minimum WOC (wait on cement) time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.

Intermediate Casing

Intermediate casing is run in a well after the surface casing but before production hole is drilled. Fully cemented intermediate casing can be necessary in some wells to prevent possible pressurization of the surface casing seat, and to effectively seal the hole below the surface casing to prevent communication between separate hydrocarbon-bearing strata and between hydrocarbon and water-bearing strata. The primary uses of intermediate casing are to 1) provide a means of controlling formation pressures and fluids below the surface casing, 2) seal off problematic zones prior to drilling the production hole and 3) ensure a casing seat of sufficient fracture strength for well control purposes. The intermediate casing's design and setting depth is typically based on various factors including anticipated or encountered geologic characteristics, wellbore conditions and the anticipated formation pressure at total depth of the well. Factors can also include the setting depth of the surface casing, occurrence of shallow gas or flows in the open hole, mud weights used to drill below intermediate casing, and well-control and safety considerations.

Current casing and cementing practices attached as conditions to all oil and gas well drilling permits state that intermediate casing string(s) and cementing requirements will be reviewed and approved by the Department on an individual well basis. The Department proposes to require, via permit condition and/or regulation, that for high-volume hydraulic fracturing the installation of intermediate casing in all wells covered under the SGEIS would be required. However, the Department may grant an exception to the intermediate casing requirement when technically justified. A request to waive the intermediate casing requirement would need to be made in writing with supporting documentation showing that environmental protection and public safety would not be compromised by omission of the intermediate string. An example of circumstances that may warrant consideration of the omission of the intermediate string and granting of the waiver could include: 1) deep set surface casing, 2) relatively shallow total depth of well and 3) absence of fluid and gas in the section between the surface casing and target interval. Such intermediate casing waiver request may also be supported by the inclusion of information on the subsurface and geologic conditions from offsetting wells, if available.

Intermediate and Production Casing Cement

Current casing and cementing practices set requirements for production casing cement and state that intermediate casing cement requirements would be reviewed and approved on an individual well basis. The requirements for production casing cement are as follows:

- Cement must extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less;
- If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows;
- Weighted fluid may be used in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem;
- Cementing shall be by the pump and plug method for all jobs deeper than 1,500 feet, with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess will suffice;
- The mixing water shall be tested for pH and temperature prior to mixing; and
- Following cementing and removal of cementing equipment, the operator shall wait until a calculated (e.g., performance chart) compressive strength of 500 psi is achieved before the casing is disturbed in any way.

The above requirements will remain in effect. In addition, the Department proposes to require, via permit condition and/or regulation, the following additional requirements for high-volume hydraulic fracturing:

1) The pre-frac form would be required as described above;

2) The setting depth of the intermediate casing would consider the cementing requirements for the intermediate casing and the production casing as noted below;

3) Intermediate casing would be cemented to the surface and cementing would be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess would suffice;

4) Production casing cement would be tied into the intermediate casing string with at least 300 feet of cement measured using True Vertical Depth (TVD). If intermediate casing

installation is waived by the Department, the production casing would be cemented to the surface;

5) Cement would conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry would be prepared to minimize its free water content in accordance with the same API specification and it would contain a gas-block additive;

6) A minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig;

~~2)~~7) The operator would run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing and the production casing. The quality and effectiveness of the cement job would be evaluated using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 “Other Testing and Information” under the heading of “Well Logging and Other Testing” of API Guidance Document HF1 (First Edition, October 2009). Remedial cementing would be required if the cement bond is not adequate to drill ahead and isolate hydraulic fracturing operations, respectively; and

8) The internal pressure test of the production string, prior to hydraulic fracturing, may not commence for at least 7 days after the primary cementing operations are completed on this casing string to help prevent the formation of a micro-annulus.

Centralizers

The use and purpose of centralizers, as recommended by GWPC, is to keep the casing centered in the wellbore so that cement adequately fills the space around it. Current casing and cementing practices attached as conditions to all oil and gas drilling permits require use of centralizers on all casing strings and specify adequate hole diameters and spacing for their use. Centralizers are required every 120 feet on surface casing, but no fewer than two may be run. These requirements will continue to apply to wells drilled for high-volume hydraulic fracturing.

The above requirements will remain in effect. In addition, the Department proposes to require, via permit condition and/or regulation, additional requirements for high-volume hydraulic fracturing:

1) At least two centralizers, one in the middle and top of the first joint of casing, would be installed on the surface and intermediate casing strings, and all bow-spring style centralizers used on all strings would conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).

Inspections to Witness Casing and Cementing Operations

Current casing and cementing practices attached as conditions to all oil and gas well drilling permits require notification to the Department prior to any surface casing pressure test when welded connections or used casing is run. In primary and principal aquifer areas, the Department must be notified prior to surface casing cementing operations and cementing cannot commence until a state inspector is present. Supplementary Permit Conditions for high-volume hydraulic fracturing require notification prior to surface, intermediate and production casing cementing for all wells, so that Department staff has the opportunity to witness the operations.

7.1.4.3 Annular Pressure Buildup

Current casing and cementing practices require that the annular space between the surface casing and the next string be vented at all times to prevent pressure build-up in the annulus. If the annular gas is to be produced, a pressure relieve valve would be installed in an appropriate manner and set at a pressure approved by the Department. Proposed Supplementary Permit Conditions for high-volume hydraulic fracturing state that "under no circumstances should the annulus between the surface casing and the next casing string be shut-in, except during a pressure test."

7.1.5 Setback from FAD Watersheds

Based on the analysis set forth in Section 6.1.5, the Department concludes that high-volume hydraulic fracturing within the NYC and Syracuse watersheds poses the risk of causing significant adverse impacts to these irreplaceable water supplies. The potential economic consequence of such impacts – loss of Filtration Avoidance – are substantial. The Department finds that standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing. Even with such controls in place, the risk of spills and other unplanned events resulting in the discharge of pollutants associated with high-volume hydraulic fracturing operations, even if relatively remote, would have significant consequences in these unfiltered water supplies. In addition, the increased industrial activity associated with well pad development, road construction and other activities associated with high-volume hydraulic fracturing is not consistent with the long-term protection of the NYC and Syracuse unfiltered surface drinking water supplies. Accordingly, the Department recommends that regulations be adopted to prohibit high-volume hydraulic fracturing in both the NYC and Skaneateles Lake watersheds, as well as in a 4,000--foot buffer area surrounding these watersheds, to provide an adequate margin of safety from the full range of operations related to high-volume hydraulic fracturing that extend away from the well pad. The Department also is presenting this proposal based on its consistency with the principles of source water protection and the "multi-barrier" approach to systematically assuring drinking water quality. See, e.g., National Research Council Watershed Management for Potable Water Supply: Assessing the NYC Strategy at 97-98 (2000); American Water Works Association, *State Source Water Protection Statement of Principles*, AWWA Mainstream (1997).

7.1.6 Hydraulic Fracturing Procedure

As detailed in this document, potential impacts to ground water from the high-volume hydraulic fracturing procedure itself are, in most cases, not anticipated. To the extent that any impacts may occur, mitigation is provided by all of the proposed mitigation measures outlined above that the Department proposes to require as permit conditions and/or regulations for high-volume hydraulic fracturing. These include:

- Requirement for private water well testing;
- Pit construction and liner specifications for well pad reserve pits;
- Requirement that covered watertight tanks be used to contain flowback water on site;
- Appropriate secondary containment measures;
- Removal of fluids within specified time frames;
- Requirement that a Department-approved BOP Use and Test Plan be followed during well drilling and/or completion operations;
- Requirement that a snubbing unit and/or coiled tubing unit with a BOP be used to enter any well with pressure and/or to drill out one or more solid-core stage plugs;

- Requirement that appropriate pressure-control procedures and equipment be used, and fracturing equipment that is pressure tested with fresh water, mud or brine ahead of pumping the hydraulic fracturing fluid;

- Requirement for notification to the Department prior to cementing surface, intermediate, and production casing;

- Requirements for cement to surface on the surface and intermediate casing strings and production casing cement tied into the intermediate casing, and a radial cement bond evaluation log or other evaluation approved by the Department on the intermediate and production casing strings;

- Requirement for the submittal of a fracturing treatment plan (as part of the pre-frac form) which includes a profile of the anticipated pressures and water volume for pumping the first stage, a description of the planned treatment interval (i.e., top and bottom of perforations expressed in both True Vertical Depth (TVD) and True Measured Depth (TMD)), the total number of stages and total volume of water for hydraulic fracturing operations;

- Use of the pre-frac form to certify wellbore integrity prior to fracturing;

- Pre-fracturing pressure testing of casing (if a frac string is not used) from surface to top of treatment interval;

- Requirement that, prior to spudding the first well on a well pad, a non-routine incident plan is in place to address potential threats to public health and the environment. The plan would include detailed descriptions of notification, reporting, and remedial measures to ensure that any non-routine incident is addressed as quickly and as completely as possible; and

- Disclosure to the Department of fracturing fluid additives so that appropriate remedial actions can be taken in response to any spill or release.

The Department proposes to require as standard permit conditions non-routine incident handling requirements to ensure that any potential environmental or public health issues are identified, reported, and remedied as expeditiously as possible. Non-routine incidents would be identified as soon as possible, and verbal notification to the department would be made within two hours of its discovery or known occurrence. Non-routine incidents may include, but are not limited to: casing, drill pipe or hydraulic fracturing equipment failures; cement failures; fishing jobs; fires; seepages; blowouts; surface chemical spills; observed leaks in surface equipment; observed pit liner failures; surface effects at previously plugged or other wells; observed effects at water wells or at the surface; complaints of water well contamination; anomalous pressure and/or flow conditions indicated or occurring during hydraulic fracturing operations; or other potentially polluting non-routine incidents or incidents that may affect the health, safety, welfare, or property of any person. If hydraulic fracturing activities are suspended pending the satisfactory completion of non-routine incident reporting and remediation, the operator would be required to receive Department approval prior to recommencing hydraulic fracturing activities in the same well.

To ensure that abandoned wells do not provide a conduit for contamination of fresh water aquifers, the Department proposes to require that the operator consult the Department's Oil and Gas database as well as property owners and tenants in the proposed spacing unit to determine whether any abandoned wells are present. If (1) the operator has property access rights, (2) the well is accessible, and (3) it is reasonable to believe based on available records and history of drilling in the area that the well's total depth may be as deep or deeper than the target formation for high-volume hydraulic fracturing, then the Department would require the operator to enter and evaluate the well, and properly plug it prior to high-volume hydraulic fracturing if the evaluation shows the well is open to the target formation or is otherwise an immediate threat to the environment. If any abandoned well is under the operator's control as owner or lessee of the pertinent mineral rights, then the operator is required to comply with the Department's existing regulations regarding shut-in or temporary abandonment if good cause exists to leave the well unplugged. This would require a demonstration that the well is in satisfactory condition to not pose a threat to the environment, including during nearby high-volume hydraulic fracturing, and a demonstrated intent to complete and/or produce the well within the time frames provided by existing regulations.

The proposed permit conditions would also include a requirement to monitor flowback rates in addition to daily and total flowback volumes. These flowback data would be required to be documented on the Well Drilling and Completion Report. Though flowback rates (and volumes) will likely vary based on differing well-specific conditions, an analysis of flowback rates may provide an indication of future flowback rates.

As explained in Section 6.1.5.2, the conclusion that harm from fracturing fluid migration up from the horizontal wellbore is not reasonably anticipated is contingent upon the presence of certain natural conditions, including 1,000 feet of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone. The presence of 1,000 feet of low-permeability rocks between the fracture zone and a drinking water source serves as a natural or inherent mitigation measure that protects against groundwater contamination from hydraulic fracturing. As stated in Section 8.4.1.1, GWPC recommended a higher level of scrutiny and protection for shallow hydraulic fracturing or when the target formation is in close proximity to underground sources of drinking water. Therefore, the Department proposes that site-specific SEQRA review be required for the following projects:

1) any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along any part of the proposed length of the wellbore is shallower than 2,000 feet below the ground surface; and

2) any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along any part of the proposed length of the wellbore is less than 1,000 feet below the base of a known freshwater supply.

Review would focus on local topographic, geologic, and hydrogeologic conditions, along with proposed fracturing procedures to determine the potential for a significant adverse impact to fresh groundwater. The need for a site-specific SEIS would be determined based upon the outcome of the review.

7.1.7 Waste Transport

7.1.7.1 Drilling and Production Waste Tracking Form

Prior to well permit issuance, the applicant would be required to provide a fluid disposal plan as required by 6 NYCRR § 554.1(c)(1). Waste transport is an integral part of that plan and transportation tracking helps to ensure that fluid wastes are disposed of properly. Because of the number of wells that may be drilled and the current limited disposal options, as well the anticipated volume of flowback water, the paucity of reliable data regarding flowback water and production brine composition from New York operations, and NORM concerns, the Department proposes to require via permit condition and/or regulation that a *Drilling and Production Waste Tracking Form* be completed and maintained by generators, haulers and receivers of all flowback water associated with activities addressed by this Supplement. The record-keeping requirements and level of detail would be similar to what is presently required for medical waste.[43] The form would be required regardless of whether waste is taken to a treatment facility, disposal well, another well pad, a landfill, or elsewhere. Flowback water transport may be reduced by treatment and reuse on the same pad for hydraulic fracturing. The *Drilling and Production Waste Tracking Form* would also be used to track the transport of production brine from wells covered under the SGEIS.

7.1.7.2 Road Spreading

Flowback Water

As explained in Chapter 5 and presented in Appendix 12, consistent with past practice, the Department began in January 2009 notifying Part 364 haulers applying for, modifying or renewing their Part 364 permit that flowback water may not be spread on roads and must be disposed of at facilities authorized by the Department or transported for use or re-use at other gas or oil wells where acceptable to the Division of Mineral Resources.

Production Brine

The notification described above informed Part 364 haulers that any entity applying for a Part 364 permit or permit modification to use production brine for road spreading must submit a petition for a BUD to the Department. However, the data available to date associated with NORM concentrations in Marcellus Shale production brine is insufficient to allow road spreading under a BUD. As more data becomes available, it is anticipated that petitions for such use will be evaluated by the Department.

For production brines that are intended for use on roads, the BUD and Part 364 permit would be issued by the Department prior to the removal of any production brine from the well site. As set forth in the notification, a BUD petition would include analytical results from an ELAP-approved laboratory of a representative sample for the following parameters: NORM, calcium, sodium, chloride, magnesium, TDS, pH, iron, barium, lead, sulfate, oil & grease, benzene, ethylbenzene, toluene, and xylene. Dependent upon the analytical results, the Department may require additional analyses. Evaluations of BUD petitions would include case-by-case

[43] http://www.dec.ny.gov/docs/materials_minerals_pdf/medwste.pdf.

assessments of potential impacts, and would establish limits on volume and frequency of application.

7.1.7.3 Flowback Water Piping

Flowback water piping and conveyances between well pads and flowback water storage tanks would be described in the fluid disposal plan required by 6 NYCRR §554.1(c)(1) and the proposed GP. The fluid disposal plan would demonstrate that pipelines and conveyances would be constructed of suitable materials, maintained in a leak-free condition, regularly inspected, and operated using all appropriate spill control and stormwater pollution prevention practices.

Upon review of the existing regulatory framework for liquid containment, the Department has determined that the existing regulatory structure established for solid waste management facilities, 6 NYCRR Part 360 (Part 360), is most applicable for the containment, operational, monitoring and closure requirements for centralized flowback water management facilities.[44]

The specific provisions of Subpart 360-6 Liquid Storage would provide the overall requirements for tanks, describing the minimum operational, monitoring and closure requirements. These provisions would cross-reference other applicable provisions of Part 360 which more specifically address system design, materials, quality assurance and certification requirements that likewise would be applicable to the flowback water containment systems discussed in the SGEIS.

7.1.7.4 Use of Tanks Instead of Impoundments for Centralized Flowback Water Storage

As previously noted, centralized flowback water surface impoundments are not covered under the SGEIS and the Department proposes that such require a site-specific environmental assessment and SEQRA determination of significance. Nevertheless, above ground storage tanks have advantages over surface impoundments. The Department's experience is that landfill owners prefer above ground storage tanks over surface impoundments for storage of landfill leachate. Tanks, while initially more expensive, experience fewer operational issues associated with liner system leakage. In addition, tanks can be easily covered to control odors and air emissions from the liquids being stored. Precipitation loading in a surface impoundment with a large surface area can, over time, increase the volumes of liquid needing treatment. Lastly,

[44] 6 NYCRR Part 360 regulations: http://www.dec.ny.gov/regs/2491.html.

above ground tanks also can be dismantled and reused. The provisions of Section 360-6.3 address the minimum regulatory requirements applicable to above ground storage tanks.

7.1.7.5 Closure Requirements

The closure requirements for liquid storage facilities under Subpart 360-6 are specified in section 360-6.6 Closure of Liquid Storage Facilities. These provisions detail the specific closure requirements for these containment structures and require any post-operation residues to be properly handled and disposed of as part of the process.

7.1.8 SPDES Discharge Permits

SPDES Discharge Permits - The federal Clean Water Act authorized the development of the *National Pollutant Discharge Elimination System* (NPDES) for implementing the requirements for all discharges to surface waters of the United States. The Department was subsequently charged, pursuant to the ECL, to develop and administer the state's program for meeting the requirements of NPDES. This program, which is authorized by the EPA, is referred to as the *State Pollutant Discharge Elimination System* (SPDES).

Regulation of discharges of pollutants to waters of the state, both surface and groundwaters, is authorized by Article 17 of the ECL. Specific controls on point source discharges are authorized by Article 17, Title 8 of the ECL. New York's SPDES program is more stringent than the federal NPDES program in that the SPDES program also regulates discharges to groundwater. The minimum threshold for applicability of SPDES to groundwater discharges is 1,000 gpd for sanitary wastewater, while discharges which include any industrial wastewater have no minimum threshold. The NYSDOH regulates discharges of less than 1,000 gpd consisting of only sanitary wastewater. The Department is authorized to issue SPDES permits for groundwater discharges for a maximum period of 10 years; permits for discharges to surface waters are issued for a maximum of 5 years.

Administration of the SPDES program is accomplished through the issuance of wastewater discharge permits, including both *individual* permits and *general* permits. Individual SPDES permits are issued to cover a single facility in one location possessing unique discharge characteristics and other factors. General SPDES permits are issued to cover a category of discharges involving the same or similar types of operations; discharge the same types of pollutants; require the same effluent limitations or operating conditions; require the same or similar monitoring; and do not have a significant impact on the environment, either individually or cumulatively, when carried out in conformance with permit provisions.

The Department is vested with the authority pursuant to state and federal law to enforce the SPDES permit requirements. The primary objective of the SPDES compliance and enforcement program is to protect water quality by ensuring that all point sources of pollution obtain a SPDES permit and comply with all terms and conditions of the permit.

The Department would employ any available compliance mechanisms that may be necessary, including formal enforcement, to attain the goal of SPDES permit compliance.

Flowback water and production brine are considered industrial wastewater. Wastewater is generated by many water users and industries. The SPDES program controls point source discharges to ground waters and surface waters. The Department proposes to require, through the well permitting process, that the permittee demonstrate prior to issuance of the drilling permit that any wastewater treatment facility proposed for disposal flowback water and production brine has the necessary treatment capacity. Furthermore, the Department proposes to continue requiring that once high-volume hydraulic fracturing operations have ceased and the gas well(s) are in the production phase, that the permittee properly collect and dispose of all production fluids generated at the site.

7.1.8.1 Treatment Facilities

SPDES permits are issued to wastewater dischargers, including treatment facilities such as POTWs operated by municipalities. SPDES permits include specific discharge limitations and monitoring requirements. The effluent limitations are typically the maximum allowable concentrations and/or mass loadings for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

POTWs

A POTW must have an approved pretreatment program, or mini-pretreatment program, developed in accordance with the above requirements in order to accept industrial wastewater from non-domestic sources covered by Pretreatment Standards which are indirectly discharged into or transported by truck or rail or otherwise introduced into POTWs.

The Department's DOW shares pretreatment program oversight (approval authority) responsibility with the EPA. Indirect discharges to POTWs are regulated by 6 NYCRR §750-2.9(b), National Pretreatment Standards, which incorporates by reference the requirements set forth under 40 CFR Part 403, "General Pretreatment Regulations for Existing and New Sources of Pollution." In accordance with DOW's TOGS 1.3.8, 6 NYCRR §750-2.9, 40 CFR Part 403, and 40 CFR 122.42, New York State POTW permittees with industrial pretreatment or mini-pretreatment programs are required to notify the Department of new discharges or substantial changes in the volume or character of pollutants discharged to the permitted POTW. The Department must then determine if the SPDES permit needs to be modified to account for the proposed discharge, change or increase.

Flowback water and production brine from wells permitted pursuant to this Supplement may only be accepted by POTWs or any other wastewater treatment plant with approved pretreatment or mini-pretreatment programs, as noted above, and an approved headworks analysis for this wastewater source in accordance with 40 CFR Part 403 and DOW's TOGS 1.3.8 and as required by the POTW's SPDES permit that includes appropriate monitoring and effluent limits for this wastewater source. The SPDES permit for the POTW would include specific discharge limitations and monitoring requirements, including routine reporting of monitoring results, tracking of these results by the Department, and a well established compliance program to deal with permit violations.

The Department's procedures for POTW acceptance of high-volume hydraulic fracturing wastewater discharges are detailed in Appendix 22 of this Supplement. Discharges that follow these procedures would provide effective mitigation of significant adverse impacts.

Private Wastewater Treatment Facilities

Privately owned facilities for the 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. The permittee would apply for SPDES permit coverage for a dedicated treatment facility would include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

Private treatment systems, which are designed, constructed, and approved to treat the parameters specific to high-volume hydraulic fracturing wastewater, including processes as discussed in Section 5-12 (Flowback Water Treatment Recycling and Reuse), may be more effective than POTWs for the treatment, disposal, and potential reuse of this source of wastewater because they can be designed and optimized to remove the parameters specific to this source of wastewater.

As noted in Chapter 5 of this revised draft SGEIS, onsite 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, generally, and reused for hydraulic fracturing with the treatment residue hauled off-site. Unless the discharge of wastewater from these treatment for reuse systems is planned, these types of facilities do not require a SPDES permit. The use of on-site treatment and reuse facilities reduces the demand for fresh water and provides effective mitigation of potential adverse impacts.

7.1.8.2 Disposal Wells

Because of the 1992 GEIS Finding that brine disposal wells require site-specific SEQRA review, mitigation measures are discussed here for informational purposes only and are not being proposed on a generic basis.

Flowback and disposal strata water quality must be fully characterized prior to permitting and injecting into a disposal well. Additional geotechnical information regarding the disposal strata’s ability to accept and retain the injected fluid is also necessary. The permittee would apply for and receive coverage under the EPA UIC program prior to applying for a SPDES permit for discharge using Form NY-2C, available on the Department’s website. The characterization and SPDES permit application process for disposal wells is similar to that for private treatment facilities.

The Department may propose monitoring requirements and/or discharge limits in the SPDES permit in addition to any requirements included in the required EPA UIC permit. These would be determined during the site-specific permitting process required by the Uniform Procedures Act and the 1992 Findings Statement. To be protective of the overlying potable water aquifers, the site-specific permitting process would consider the following topics:

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

New York State currently has six permitted underground disposal wells, three of which are used to dispose of brine produced with oil and /or gas. However, these wells are privately owned and currently are approved to inject only their own brine. Use of an existing permitted underground disposal well would require a modification of the existing UIC and SPDES permits for the existing wells to accept flowback.

The Department notes that potential impacts as described in Chapter 6 of this revised draft SGEIS have occurred in other states, and remain a concern. With the above mitigation measures in place, combined with permit monitoring and oversight, there would be no significant impacts from waste transport and disposal in connection with high-volume hydraulic fracturing wastewater.

7.1.9 Solids Disposal

Cuttings may be managed within a closed-loop tank system or within the lined reserve pit. If cuttings are contained within the reserve pit and a common reserve pit is used for multiple wells on the pad, cuttings may have to be removed several times to maintain the required two feet of freeboard set forth in Section 7.1.3.2. Care must be taken during this operation not to damage the liner.

Cuttings contaminated with oil-based or polymer-based mud could not be buried on site; they would be managed in a closed-loop tank system and removed from the site for disposal in a Part 360 solid waste facility. Supplementary permit conditions pertaining to the management of drill cuttings from high-volume hydraulic fracturing require consultation with the Department's Division of Materials Management for the disposal of any cuttings associated with water-based mud-drilling and any pit liner associated with water-based or brine-based mud-drilling where the water-based or brine-based mud contains chemical additives. Supplemental permit conditions also dictate that any cuttings required to be disposed of off-site, including at a landfill, be managed on-site within a closed-loop tank system rather than a reserve pit.

As the basal portion of the Marcellus has been reported to contain abundant pyrite (an iron sulfide mineral),[45] there exists the potential that cuttings derived from this interval and placed in reserve pits may oxidize and leach, resulting in an acidic discharge to groundwater, commonly referred to as acid rock drainage (ARD). A site-specific ARD-mitigation plan would be required to be prepared and followed by the operator for on-site burial of Marcellus Shale cuttings from horizontal drilling in the Marcellus Shale if the operator elects to bury these cuttings. The ARD-mitigation plan would be designed to neutralize acid drainage through the emplacement of basic carbonate materials (e.g., waste lime or limestone cuttings) prior to on-site burial. The pyritic drill cuttings and the carbonate materials would be mixed thoroughly and compacted prior to reclamation of the pit area. This method was demonstrated to be effective in an ARD-abatement project jointly conducted by Penn DOT and PADEP during construction of U.S. Route 22 near Lewiston PA in 2004.[46]

Alternatively, if the operator elects or is required (for reasons related to drilling fluid composition, as previously discussed) to utilize an off-site disposal facility for disposal of cuttings from horizontal drilling in the Marcellus Shale, then no ARD-mitigation plan is required. In such instances however, supplementary permit conditions require that these cuttings

[45] Lash and Engelder, 2008.

[46] Smith et al, 2006.

be managed and contained on-site within a closed-loop tank system rather than within a reserve pit, prior to removal for off-site disposal.

Annular disposal of drill cuttings has also been proposed; however, this is not an acceptable practice in New York and is prohibited by the high-volume hydraulic fracturing Supplementary Permit Conditions.

Although not directly related to a water resources impact, consideration also should be given to monitoring and mitigating subsidence by adding fill as any uncontaminated drill cuttings that are buried on site dewater and consolidate.

7.1.10 Protecting NYC's Subsurface Water Supply Infrastructure

The advent, in the late 1990s and early 2000s, of geothermal well drilling – also regulated under ECL 23 if the wells are deeper than 500 feet – led to mutually agreed upon protocols between the Department and the NYCDEP for processing permits to drill in NYC and Delaware, Dutchess, Greene, Orange, Putnam, Rockland, Schoharie, Sullivan, Ulster and Westchester Counties. The Department agreed to notify NYCDEP of any proposed well in the counties outside of NYC, so that NYCDEP could determine if the proposed surface location is within a 1,000-foot wide corridor surrounding a water tunnel or aqueduct. For any well that NYCDEP confirms is outside the corridor, the Department processes the permit application following its normal procedures without any further NYCDEP involvement to address subsurface infrastructure.

For any well within the 1,000-foot corridor, the Department notifies the applicant that the proposed drilling is an unlisted action and may pose a significant threat to a municipal water supply, necessitating a site-specific SEQRA finding. A negative declaration is only filed upon a demonstration to NYCDEP's satisfaction, through proposed drilling and deviation surveying protocols, that it is feasible to drill at the proposed location with confidence that there would be no impact to tunnels or aqueducts. NYCDEP is provided with a copy of each application for a permit to drill, and any permit issued requires notification to NYCDEP prior to drilling commencement.[47]

Prior to reaching the above-described agreement with NYCDEP, Department staff had considered applying the 660-foot protective buffer for underground mining operations that is provided by the oil and gas regulations to NYC's underground water tunnels and aqueducts.[48] However, those regulations require the underground mine operator (or, in this case, the tunnel operator) to provide detailed location information regarding its underground property rights to the Department. NYCDEP has not provided such maps for the subject counties, and the 1,000-foot protective corridor suggested by NYCDEP was agreeable to Department staff because it is more protective and is consistent with the 1992 GEIS criteria for requiring supplemental environmental review for proposed well locations within 1,000 feet of municipal water supply wells.

To prevent impacts to NYC's subsurface water supply infrastructure, Department staff would continue to follow the above protocol for any proposed ECL 23 well, including any proposed gas well, in the NYC Watershed. Except for the horizontal drilling and hydraulic fracturing that may occur thousands of feet below the depth of any tunnel or aqueduct, the methods and technologies for geothermal wells are the same as for natural gas wells.

7.1.11 Setbacks

Setbacks provide a margin of safety should the operational mitigation measures fail, and are therefore a useful risk management tool. The NYSDOH recognizes separation distances, or setbacks, as a crucial element of protecting water resources against contamination.[49] While the cited reference pertains specifically to drinking water wells, setbacks also mitigate potential impacts to other water resources. As established in the 1992 GEIS with respect to municipal water supply wells, setback distances can be used to help define the level of environmental review and mitigation required for a specific proposed activity.

The proposed setback distances advanced herein reflect consideration of the following information reviewed by Department staff in DMN and DOW:

[49] http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs1_additional_measures.htm, viewed 8/26/09.

- The 1992 GEIS and its Findings;

- NYSDOH's required water well separation distances, set forth in Appendix 5-B of the State Sanitary Code.[50] Although sites specifically related to natural gas development and production are not explicitly listed among the potential contaminant sources addressed by Appendix 5-B, NYSDOH staff assisted Department staff in identifying listed sources which are analogous to activities related to high-volume hydraulic fracturing;

- Results and discussion provided by Alpha Environmental Consultants, Inc. (Alpha), to NYSERDA regarding Alpha's survey of regulations related to natural gas development activities in Pennsylvania, Colorado, New Mexico, Wyoming , Texas (including the City of Fort Worth), West Virginia, Louisiana, Ohio and Arkansas;[51]

- Results and discussion provided by Alpha to NYSERDA regarding Alpha's review of the rules and regulations pertaining to protection of water supplies in NYC's Watershed.[52] Again, although natural gas development activities are not specifically addressed, and this SGEIS does not cover high-volume hydraulic fracturing in the NYC or Syracuse watersheds, Alpha identified activities which could be considered analogous to aspects of high-volume hydraulic fracturing, including:

    - Hazardous materials storage;
    - Radioactive waste disposal;
    - Storage of petroleum products;
    - Impervious surfaces;
    - Stormwater pollution prevention plans;
    - Miscellaneous point sources; and
    - Solid waste disposal

- Local watershed rules and regulations for various jurisdictions within the Marcellus and Utica Shale fairways. The counties searched included Broome, Chemung, Chenango, Cortland, Delaware, Madison, Otsego, Steuben, Sullivan, Tioga and Tompkins. Local watershed rules and regulations include setbacks from water supplies related to the following activities which are potentially analogous to aspects of high-volume hydraulic fracturing:

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[50] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.

[51] Alpha, 2009, Tables 2.1 - 2.10.

[52] Alpha, 2009, p. 94.

- Chlorides/salt storage;
- Burial of storage containers containing toxic chemicals or substances;
- Disposal of radioactive waste by burial in soil; and
- Direct discharge of polluted liquid to the ground or a water body.

7.1.11.1 Setbacks from Groundwater Resources

The following discussion pertains to the lateral distance, measured at the surface, to a water supply or spring from the closest edge of the well pad.

The proposed well and well pad setbacks apply to well permit applications where the target fracturing zone is either at least 2,000 feet deep or 1,000 feet below the underground water supply. These wells would be drilled vertically through the aquifer, so that the location of the aquifer penetration at each well corresponds to the well's location on the ground surface. Well permit applications where the target fracturing zone is less than either 2,000 feet deep or 1,000 feet below a known underground water supply are addressed in Section 7.1.5.

The EAF addendum for high-volume hydraulic fracturing would require evidence of diligent efforts by the well operator to determine the existence of public or private water wells and domestic-supply springs within half a mile (2,640 feet) of any proposed drilling location. The Department proposes that this distance is adequate to ensure the 2,000-foot setback discussed herein threshold for public water supply wells is properly applied. The operator would be required to identify the wells and springs, and provide available information about their depth, completed interval and use. Use information would include whether the well is public or private, community or non-community and of what type in terms of the facility or establishment it serves if it is not a residential well. Information sources available to the operator include:

- direct contact with municipal officials;
- direct communication with property owners and tenants;
- communication with adjacent lessees;
- EPA's Safe Drinking Water Act Information System database, available at http://oaspub.epa.gov/enviro/sdw_form_v2.create_page?state_abbr=NY; and

- Department's Water Well Information search wizard, available at http://www.dec.ny.gov/cfmx/extapps/WaterWell/index.cfm?view=searchByCounty.

Upon receipt of a well permit application, Department staff would compare the operator's well list to internally available information and notify the operator of any discrepancies or additional wells that are indicated within half a mile of the proposed well pad. The operator would be required to amend its EAF Addendum accordingly.

The EAF Addendum for high-volume hydraulic fracturing would also require well operators to identify any wells listed within the Department's Oil & Gas Database[53] within a) the spacing unit of the proposed well and b) within 1 mile (5,280 feet) of the proposed well location. For each well identified, operators would be required to provide information regarding the distance from the surface location of the existing well to the surface location of the proposed well, as well as information regarding the quantity and type of any freshwater, brine, oil or gas encountered during the drilling of the well, as recorded on the Department's Well Drilling and Completion Report.

This requirement would help to ensure that available information on nearby wells is considered by the operator while designing the proposed wellbore. Additionally, this information can be used by Department staff to review any necessary Department well files to ensure that the operator's proposed wellbore design is sufficient to protect ground water resources.

Public Water Supplies and Primary and Principal Aquifers

The Department's 1992 GEIS concluded that issuance of a permit to drill less than 1,000 feet from a municipal water supply well is considered "always significant" and requires a site-specific SEIS to analyze groundwater hydrology, potential impacts and propose mitigation measures. The 1992 GEIS also found that any proposed well location between 1,000 and 2,000 feet from a municipal water supply well requires a site-specific assessment and SEQRA determination, and may require a site-specific SEIS. The 1992 GEIS provides the discretion to apply the same process to other public water supply wells.

[53] The Department's Oil & Gas Database contains information on more than 35,000 oil, gas, storage, solution salt, stratigraphic, and geothermal wells categorized under ECL 23 as Regulated Wells. The Oil & Gas database can be accessed on the Department's website at http://www.dec.ny.gov/cfmx/extapps/GasOil/.

For multi-well pads and high-volume hydraulic fracturing, the Department proposes that site disturbance associated with such operations be prohibited within 2,000 feet of any public (municipal or otherwise) water supply well, reservoirs, natural lake or man-made impoundments (except engineered impoundments constructed for fresh water storage associated with fracturing operations), and river or stream intake, in order to safeguard against significant adverse impacts due to surface spills and leaks on the well pad that could impact the groundwater supply. As noted, these setbacks would be measured from the closest edge of the well pad. The Department will re-evaluate the necessity of this approach after three years of experience issuing permits in areas outside of the 2,000-foot boundary.

In addition, as stated in sub-section 7.1.3, the Department proposes that for at least two years the surface disturbance associated with high-volume hydraulic fracturing, including well pad and associated road construction and operation, be prohibited within 500 feet of primary aquifers. The Department further proposes that a site-specific SEQRA review be required for high-volume hydraulic fracturing projects at any proposed well pad within or within 500 feet of a Principal Aquifer. As noted, these setbacks would be measured from the closest edge of the well pad. The Department will re-evaluate the necessity of this approach after two years of experience issuing permits in areas outside of these restricted areas.

Private Water Wells and Domestic Supply Springs

Chapter 6 describes potential impacts related to high-volume hydraulic fracturing that may require enhanced protections for private water wells and domestic-supply springs. These concerns stem more from handling greater fluid volumes on the surface than from downhole activities. Fluid and chemicals could be present and handled anywhere on the well pad. Setbacks, therefore, would be measured from the edge of the well pad.

As stated above, uncovered pits or open surface impoundments that could contain flowback water are analogous to "chemical storage site(s) not protected from the elements," which are subject to a 300-foot separation distance from water wells under Appendix 5-B of the State Sanitary Code.[54] Flowback water tanks and additive containers could be compared to "chemical storage site(s) protected from the elements," which require a 100-foot setback from water

[54] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.

wells.[55] Handling and mixing of hydraulic fracturing additives onsite is comparable to "fertilizer and/or pesticide mixing and/or clean up areas," which require a 150-foot distance from water wells.[56]

The Department proposes that it will not issue well permits for high-volume hydraulic fracturing within 500 feet of a private water well or domestic-supply spring, unless waived by the landowner.

7.1.11.2 Setbacks from Other Surface Water Resources

Application of setbacks from surface water resources prevents direct flow of the full, undiluted volume of a spilled contaminant into a surface water body. Some amount of evaporation or soil adsorption would occur in the event of a spill. Existing regulations prohibit the surface location of an oil or gas well within 50 feet of any "public stream, river or other body of water."[57] The 1992 GEIS proposed that this distance be increased to 150 feet and apply to the entire well site instead of just the well itself.

Significant surface spills at well pads which could contaminate surface water bodies, including municipal supplies, are most likely to occur during activities which are closely observed and controlled by personnel at the site. More people are present to monitor operations at the site during high-volume hydraulic fracturing and flowback operations than at any other time period in the life of the well pad. Therefore, any surface spills during these operations are likely to be quickly detected and addressed rather than continue undetected for a lengthy time period. Other factors which mitigate the risk of surface water contamination resulting from well pad operations include the following:

- Required stormwater permit coverage, including a SWPPP;
- Supplementary Permit Conditions for High-Volume Hydraulic Fracturing (see Appendix 10), which are proposed to include:
    - Pit construction and liner specifications for well pad reserve pits;

[55] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.

[56] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.

[57] 6 NYCRR §553.2.

- Requirement that closed-loop tank systems be used instead of reserve pits for any horizontal drilling in the Marcellus Shale without an ARD- mitigation plan for on-site burial of cuttings and for any drilling requiring cuttings to be disposed of off-site;
- Requirement that tanks be used to contain flowback water on site;
- Appropriate secondary containment measures;
- Use of appropriate pressure-control procedures and equipment, including blow-out prevention equipment that is tested on-site prior to drilling ahead and fracturing equipment that is pressure tested with fresh water, mud or brine ahead of pumping fracturing fluid; and
- Pre-fracturing pressure testing of casing from surface to top of treatment interval.

- SGEIS setbacks related to potential surface activities measured from the edge of the well pad instead of from the well. Municipal ownership of land surrounding municipal surface water supplies may provide additional protection if the municipal-owned buffer exceeds the setback distance. Other waterfront owners may decline to lease or offer only non-surface entry leases [e.g., Otsego Lake owners around the lake include NYS (Glimmerglass State Park), Clark Foundation, etc.]; and

- The Department's existing requirement for a Freshwater Wetlands Permit in wetland or 100-foot buffer zone.

With respect to surface municipal supplies, the 1992 GEIS found that a 150-foot distance between the wellsite and a surface water supply would provide adequate protection in the event of an accidental spill. Required erosion and sedimentation control plans would address potential impacts to nearby water bodies from ground disturbance. As discussed elsewhere in this document, the Department has since determined that stormwater permit coverage is required for disturbance greater than one acre.

Reservoir setbacks for comparable activities addressed in some local Watershed Rules and Regulations establish various setbacks between 20 and 1,000 feet, but they generally pertain either to actual burial of materials for disposal purposes or direct discharges to the ground or to surface-water bodies. Burial or direct discharges to the ground of fracturing fluid, additive chemicals or flowback water are not proposed and would not be approved. The only on-site burial discussed in Chapter 5 of this document pertains to uncontaminated cuttings and pit-liners associated with air or fresh-water drilling, as allowed under the 1992 GEIS. Direct discharges to surface water bodies are regulated by the Department's SPDES permitting program.

The required setbacks from surface water supplies in other states reviewed by Alpha vary between 100 and 350 feet.[58] Colorado's new Public Water System Protection rule requires a variance for surface activity, including drilling, completion, production and storage, within 300 feet of a surface public water supply.[59]

Many local Watershed Rules and Regulations require smaller setbacks from watercourses, as specifically defined within the watershed (see Section 2.4.4.3) than from reservoirs.

Based on the above information and mitigating factors, the Department proposes that site-specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.

7.2 Protecting Floodplains

The Department proposes to require, through permit condition and/or regulation, that high-volume hydraulic fracturing not be permitted within 100-year floodplains in order to mitigate significant adverse impacts from such operations if located within 100-year floodplains.

7.3 Protecting Freshwater Wetlands

Section 2.4.10 summarizes the State's Freshwater Wetlands regulatory program, which addresses activities within 100 feet of regulated wetlands. In addition, the federal government regulates development activities in wetlands under Section 404 of the Clean Water Act.

The Department found in 1992 that issuance of a well permit when another Department permit is necessary requires a site-specific SEQRA determination relative to the activities or resources addressed by the other permit. In such instances, which include Freshwater Wetlands Permits, the well permit is not issued until the SEQRA process is complete and the other permit is issued.

[58] Alpha, 2009, pp. 41-45.

[59] http://cogcc.state.co.us/RR_Docs_new/rules/300series.pdf, viewed 8/26/09.

Mitigation measures for avoiding wetland impacts from well development activities are described in Chapter 8 of the 1992 GEIS, which provides that well permits are issued for locations in wetlands only when alternate locations are not available. Potential mitigation measures are not limited to those discussed in the 1992 GEIS, but may include other alternatives recommended by Fish, Wildlife and Marine Resources staff based on current techniques and practices. Additional measures proposed in this Supplement include the following:

- Requirement that, to the extent practical, fueling tanks not be placed within 500 feet of a wetland (Section 7.1.3.1);
- Requirement for secondary containment consistent with the Department's SPOTS 10 for any fueling tank, regardless of size (Section 7.1.3.1); and

7.4 Mitigating Potential Significant Impacts on Ecosystems and Wildlife

Fragmentation of habitat, potential transfer of invasive species, and potential impacts to endangered and threatened species are identified in Chapter 6 as potential significant adverse ecosystem and wildlife impacts specifically related to high-volume hydraulic fracturing that are not addressed by the 1992 GEIS. The following text identifies mitigation measures to address significant impacts of fragmentation of habitat, potential transfer of invasive species, and endangered and threatened species, as well as the use of certain State-owned land.

7.4.1 Protecting Terrestrial Habitats and Wildlife

Significant adverse impacts to habitats, wildlife, and biodiversity from site disturbance associated with high-volume hydraulic fracturing in the area underlain by the Marcellus Shale in New York will be unavoidable. In particular, the most significant potential wildlife impact associated with high-volume hydraulic fracturing is fragmentation of rare interior forest and grassland habitats and the resulting impacts to the species that depend on those habitats. However, the following specific mitigation measures would prevent some impacts, minimize others, and provide valuable information for better understanding the impacts of habitat fragmentation on New York's wildlife from multi-pad horizontal gas wells.

7.4.1.1 BMPs for Reducing Direct Impacts at Individual Well Sites

The Department proposes that the BMPs listed below be required mitigation measures to reduce impacts associated with development of individual wellpads and appurtenances located in natural habitats. During the permit review process, site-specific conditions would be considered to determine applicability of each BMP and permit conditions included as appropriate.

- Require multiple wells on single pads wherever possible;

- Design well pads to fit the available landscape and minimize tree removal;[60]

- Require "soft" edges around forest clearings by either maintaining existing shrub areas, planting shrubs, or allowing shrub areas to grow;

- Limit mowing to one cutting per year or less after the construction phase of well pads is completed. Mowing would not occur during the nesting season for grassland birds (April 23 – August 15);

- When well pads are placed in large patches of grassland habitat (greater than 30 acres) located within Grassland Focus Areas (as described in Section 7.4.1.2), construction and drilling activities are prohibited during grassland bird nesting season (April 23 – August 15);

- When well pads are placed in large patches of grassland habitat (greater than 30 acres) located within Grassland Focus Areas, minimize impacts from dust during the grassland bird nesting season (April 23 – August 15) by using dust palliatives and other appropriate measures to reduce dust;

- Require lighting used at wellpads to shine downward during bird migration periods (April 1 – June 1 and August 15 – October 15);

- Limit the total area of disturbed ground, number of well pads, and especially, the linear distance of roads, where practicable;[61]

[60] Environmental Law Clinic 2010.

[61] New Mexico Dept Game & Fish, 2007.

- Design roads to lessen impacts (including two-track roads and oak mats in low-volume areas[62]) and limit canopy gaps;[63]

- Require roads, water lines, and well pads to follow existing road networks and be located as close as possible to existing road networks to minimize disturbance;

- Gate single-purpose roads to limit human disturbance; and[64]

- Require reclamation of non-productive, plugged, and abandoned wells, well pads, roads and other infrastructure areas. Reclamation would be conducted as soon as practicable and would include interim steps to establish appropriate vegetation during substantial periods of inactivity. Native tree, shrub, and grass species should be used in appropriate habitats.

7.4.1.2 Reducing Indirect and Cumulative Impacts of Habitat Fragmentation

The best opportunity for reducing indirect and cumulative impacts is to preserve existing blocks of the critically important grassland and interior forest habitats identified in Grassland and Forest Focus Areas (Figure 7.2) by avoiding site disturbance (wellpad construction) in those areas.

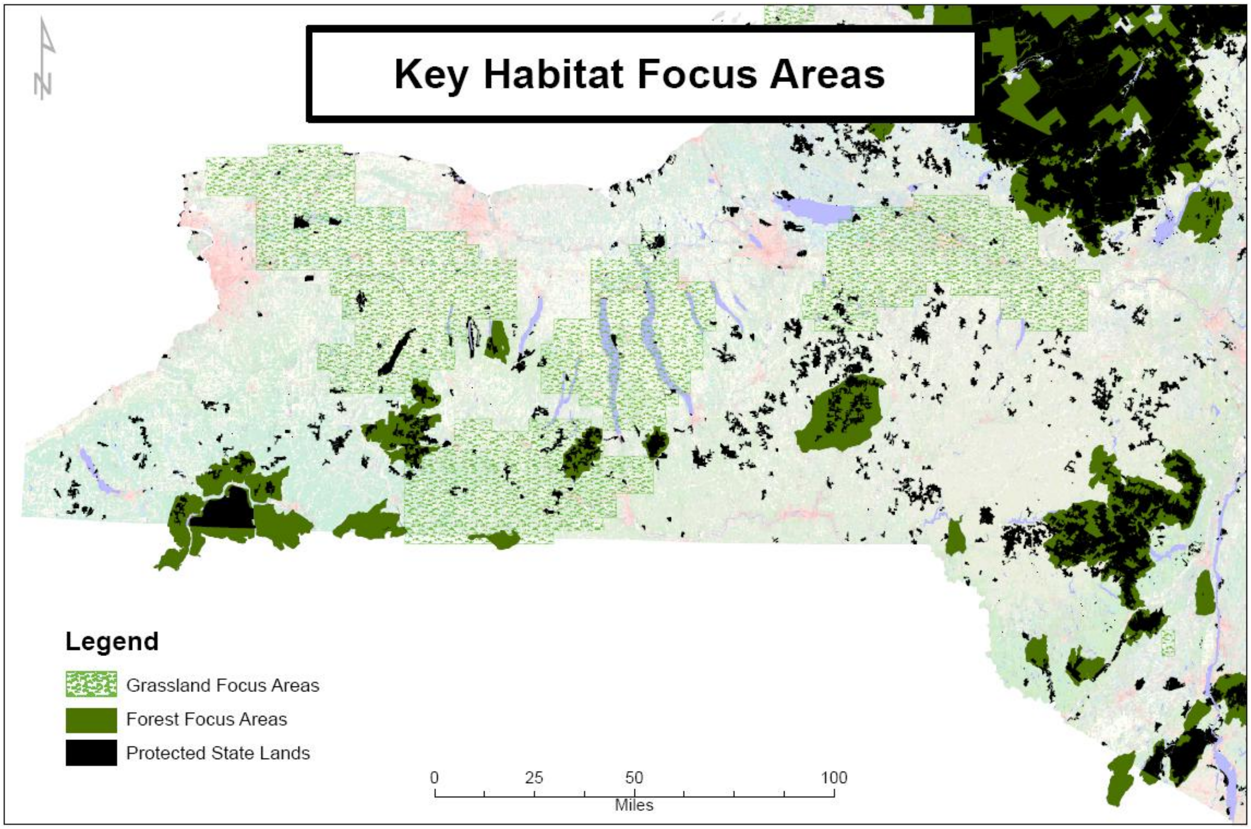
Grassland Focus Areas represent those areas within the State that are most important for grassland nesting birds. Forest Focus Areas represent those areas in the State that contain large blocks of forest interior habitats. Development in these areas would be conditioned as outlined below to mitigate impacts on wildlife from habitat fragmentation. The following measures are considered necessary to mitigate the cumulative impacts of habitat fragmentation for these critically important habitat types while not strictly prohibiting development.

[62] Weller et al., 2002.

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

[64] New Mexico Dept Game & Fish, 2007.

Figure 7.2 - Key Habitat Areas for Protecting Grassland and Interior Forest Habitats
(Updated August 2011)



Grassland Focus Areas

Grassland Focus Areas depicted in Figure 7.2 were determined by a group of grassland bird experts, including Department staff with input from outside experts representing federal agencies and academia.[65] The focus areas were derived from Breeding Bird Atlas (BBA) data from 2002-2004;[66] they were further modified by expert knowledge, and then followed up with a 2-year field verification study before being finalized. They represent areas of New York State that contain the most important grassland habitat mosaics.

The 2006 BBA provided the core dataset for delineating Grassland Focus Areas. All atlas blocks with a high richness of breeding grassland birds, as well as contiguous blocks also supporting grassland species, were included in the focus areas. The target for the focus areas was to

[65] See Morgan and Burger 2008.

[66] McGowan and Corwin 2008 or visit DEC's website (http://www/dec/ny.gov/animals/7312.html).

"capture" or include at least 50% of the BBA blocks where each of the grassland species was found to be breeding across the state. The focus areas were able to reach that target for all but the most widespread species. Although the BBA does not provide estimates of abundance or densities, one of the criteria for inclusion in a focus area was contiguity with adjacent blocks containing grassland birds; analyses indicate that such blocks contain significantly higher abundances of the target species than isolated blocks.

Extensive field surveys were conducted in 2005 and 2006 throughout the focus areas. These surveys collected distribution and abundance data to confirm that the analysis of the breeding-bird data reflected actual conditions in the field (Table 7.4). A total of 487 different habitat patches were surveyed statewide. In some cases, focus area boundaries were adjusted based on field survey data. The overall process resulted in the identification of 8 focus areas that support New York's grassland breeding birds, 4 of which occur in the area underlain by the Marcellus Shale.

Table 7.4 - Principal Species Found in the Four Grassland Focus Areas within the area underlain by the Marcellus Shale in New York (New July 2011)

Grassland Focus Area	**Species**
Western Area	Upland sandpiper, vesper sparrow, horned leak, savannah sparrow, short-eared owl*
Southern Area	Northern Harrier, grasshopper sparrow, Eastern meadowlark, savannah sparrow
Middle Northern Area	Vesper sparrow, grasshopper sparrow, horned lark, savannah sparrow, short-eared owl*
Eastern Area	Northern harrier, short-eared owl*
*Wintering only	

Specific Mitigation Measures to Reduce Impacts to Grasslands

In order to mitigate impacts from fragmentation of grassland habitats, the Department proposes to require, through the permit process and/or by regulation, that surface disturbance associated with high-volume hydraulic fracturing activities in contiguous grassland habitat patches of 30 acres or more within Grassland Focus Areas would be based on the findings of a site-specific ecological assessment and implementation of mitigation measures identified as part of such ecological assessment, in addition to the BMPs required for all disturbances in grassland areas that are identified in Section 7.4.1.1. This ecological assessment would include pre-disturbance biological studies and an evaluation of potential impacts on grassland birds from the project. Pre-disturbance studies would be required to be conducted by qualified biologists and would be required to include a compilation of historical information on grassland bird use of the area and a minimum of one year of field surveys at the site to determine the current extent, if any, of grassland bird use of the site. Should the Department decide to issue a permit after reviewing the ecological assessment, the applicant would be required to implement supplemental mitigation measures by locating the site disturbance as close to the edge of the grassland patch as feasible and proposing additional mitigation measures (e.g., conservation easements, habitat enhancement). In addition, enhanced monitoring of grassland birds during the construction phase of the project and for a minimum period of two years following active high-volume hydraulic fracturing activities (i.e., following well completion) would be required.

Explanation for 30 Acre Threshold: Many of New York's rarest bird species that rely on grasslands are affected by the size of a grassland patch. Several species of conservation concern rely on larger-sized grassland patches and show strong correlation to a minimum patch size if they are to be present and to successfully breed. Minimum patch sizes will vary by species, and by surrounding land uses, but a minimum patch size of 30-100 acres is warranted to protect a wide assemblage of grassland-dependent species.[67] Although a larger patch size is necessary for raptor species, a minimum 30 acres of grassland is needed to provide enough suitable habitat for a diversity of grassland species. Grasslands less than 30 acres in size are of less importance since they do not provide habitat for many of the rarer grassland bird species.[68] The Grassland

[67] USFWS, Sample and Mossman 1997, Mitchell et al, 2000.

[68] USFWS, Sample and Mossman 1997, Mitchell et al, 2000.

Focus Areas cover about 22% of the area underlain by the Marcellus Shale. However, the actual impacts on Marcellus development would affect less area for two reasons. First, only those portions of the Grassland Focus Areas meeting the minimum patch size requirement would be subject to the aforementioned additional restrictions on surface disturbance. Second, even in areas where surface disturbance should be avoided, gas deposits could be accessed horizontally from adjacent areas where the restriction does not apply.

Forest Focus Areas

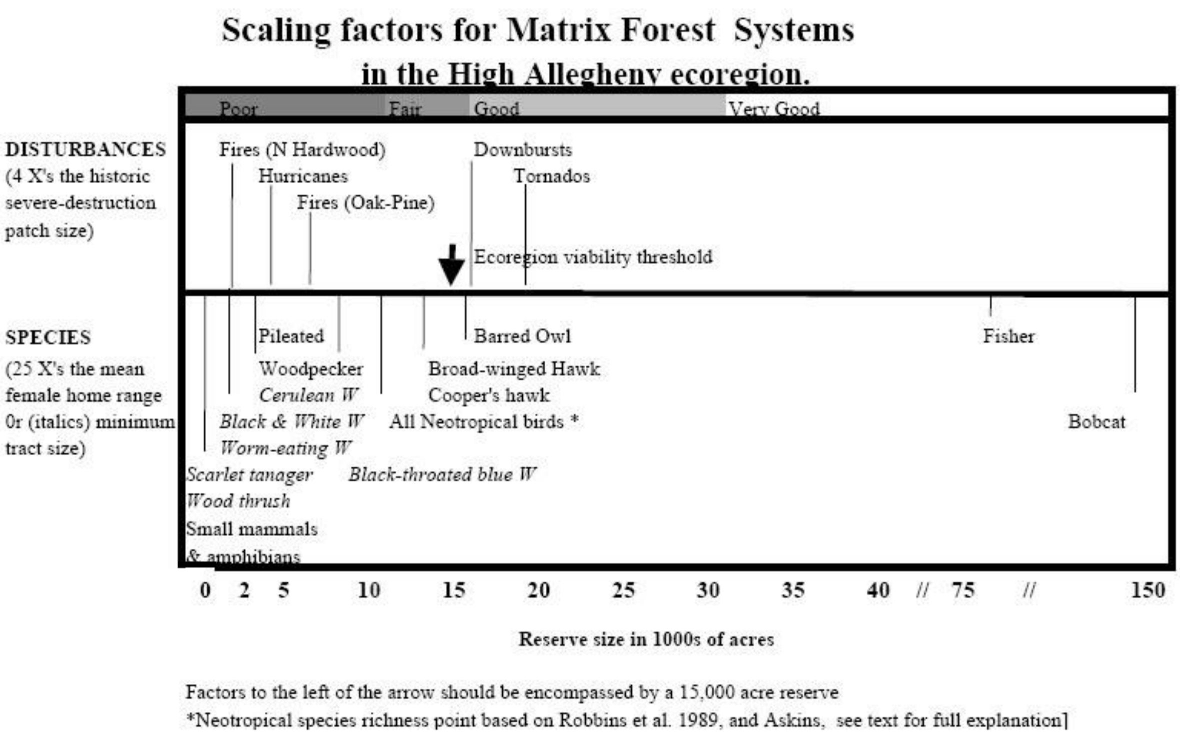
Forest Focus Areas depicted in Figure 7.2 were based on Forest Matrix Blocks developed by The Nature Conservancy (TNC).[69] TNC's goal in developing Forest Matrix Blocks was to estimate viability and resilience of forests and determine those areas where forest structure, biological processes, and biological composition are most intact. Resilient forest ecosystems can absorb, buffer, and recover from the full range of natural disturbances. TNC used three characteristics in developing their Forest Matrix Blocks: size, condition, and landscape context. Size was based on the key factors of the area necessary to absorb natural disturbance and species area requirements (see Figure 7.3).

- **Natural disturbances and minimum dynamic area:** Eastern forests are subject to hurricanes, tornadoes, fires, ice storms, downbursts, and outbreaks of insects or disease. While most of these disturbances are small and recovery is fast, damage from larger catastrophic events may last for decades. Resilient forest ecosystems can absorb, buffer, and recover from the full range of natural disturbances. The effects of catastrophic events are typically spread across a landscape in an uneven way. Patches of severe damage are embedded in larger areas of moderate or light disturbance. Using historical records, vegetation studies, air photo analysis, and expert interviews, TNC scientists determined the size and extent of patches of severe damage for each disturbance type expected over one century. Historic patterns in the Northeast suggest that an area of approximately four times the size of the largest severe damage patch is necessary for a particular matrix block to remain adequately resilient.

[69] TNC, 2003.

- **Breeding territories and area sensitive species:** Forest ecosystems must also be big enough to support characteristic interior species, including birds, mammals, herptiles, and insects. Many species establish and defend territories during breeding season, from which they obtain resources to raise their young. Twenty-five times the average size of a territory, together with information on other minimum area restrictions for that species, may be used as an estimate of the space needed for a small population. This reflects a rule of thumb developed for zoo populations on the number of breeding individuals required to conserve genetic diversity over generations (Figure 7.3);[70]

Figure 7.3 - Scaling Factors for Matrix Forest Systems in the High Allegheny Ecoregion[71] (New July 2011)



[70] TNC, 2003.

[71] From TNC, 2004.

- Condition was based on the key factors of structural legacies, fragmenting features, and biotic composition. TNC's criteria for viable forest condition were: low road density with few or no bisecting roads; large regions of core interior habitat with no obvious fragmenting feature; evidence of the presence of forest breeding species; regions of old growth forest; mixed age forests with large amounts of structure or forests with no agricultural history; no obvious loss of native dominants; mid-sized or wide-ranging carnivores; composition not dominated by weedy or exotic species; no disproportional amount of damage by pathogens; and minimal spraying or salvage cutting by current owners. Matrix blocks are bounded by fragmenting features such as roads, railroads, major utility lines, and major shorelines. The bounding block features were chosen due to their ecological impact on biodiversity in terms of fragmentation, dispersion, edge-effects, and invasive species; and

- Landscape context was based on the key factors of edge-effect buffers, wide-ranging species, gradients, and structural retention. In evaluating landscape context, TNC evaluated and recorded information on the surrounding landscape context for all matrix communities. TNC generally considered areas embedded in much larger areas of forest to be more viable than those embedded in a sea of residential development and agriculture. However, no area was rejected solely on the basis of its landscape context because the matrix forests in many of the poorer landscape contexts currently serve as critical habitat for forest interior species and may be the best example of the forest ecosystem type. Thus, this criterion was used to reject or accept some examples that were initially of questionable size and condition.

TNC applied the territory size and disturbance factors to all of the ecoregions in the Northeast, and tailored minimum size thresholds for matrix blocks to each ecoregion's forested extent, ecology, and natural disturbance history. The area underlain by the Marcellus Shale in New York is located in the High Allegheny Plateau (HAL) ecoregion (minimum block size of 15,000 acres), and contains 26 forest matrix blocks ranging in size from 17,000 acres to 176,000 acres, totaling 1.3 million acres. These matrix blocks are comprised of several dominant forest community types, including Northern hardwoods, maple-birch-beech forest, oak hickory forest and Allegheny oak forests.[72]

Specific Mitigation Measures to Reduce Impacts to Forests

In order to mitigate impacts from fragmentation of forest interior habitats, the Department proposes to require, through the permit process and/or by regulation, that surface disturbance associated with high-volume hydraulic fracturing activities in contiguous forest patches of 150 acres or more within Forest Focus Areas would be based on the findings of a site-specific ecological assessment and implementation of mitigation measures identified as part of such ecological assessment, in addition to the BMPs required for all disturbances in forested areas that are identified in Section 7.4.1.1. The ecological assessment would include pre-disturbance biological studies and an evaluation of potential impacts on forest interior birds from the project. Pre-disturbance studies would be required to be conducted by qualified biologists and would be required to include a compilation of historical information on forest interior bird use of the area and a minimum of one year of field surveys at the site to determine the current extent, if any, of forest interior bird use of the site. Should the Department decide to issue a permit after reviewing the ecological assessment, the applicant would be required to implement supplemental mitigation measures by locating the site disturbance as close to the edge of the forest patch as feasible and proposing additional mitigation measures (e.g., conservation easements, habitat enhancement). In addition, enhanced monitoring of forest interior birds during the construction phase of the project and for a minimum period of two years following the end of high-volume hydraulic fracturing activities (i.e., following date of well completion) would be required.

Explanation for 150-Acre Threshold: Fragmentation of large forest blocks can negatively affect breeding birds that require interior forest habitat for successful reproduction. Fragmentation due to human development of forest openings and structures that are relatively permanent will fragment habitats, create more edge, and reduce breeding success. Human-induced openings can influence breeding bird productivity several hundred feet from the edge of the forest through increased predation and increased nest parasitism. There is a wide diversity of bird species that rely on forest interior habitats to breed. As such, patch size requirements can

[72] TNC, 2002.

vary widely by species, and can be influenced by surrounding land cover as well as the amount of forest cover on the landscape. Previous research on forest interior birds suggests that the minimum forest patch size needed to support forest breeding species ranges between 100 and 500 acres[73]. A 100-acre patch size is the minimum that would probably support a relatively diverse assemblage of forest breeding birds. Additional research indicates that the negative impacts along a forest edge extend between 200-500 feet into the forest.[74] If we assume a 100-acre forest patch with a 300-foot forested buffer, the minimum patch size for forest interior birds is approximately 150 acres of contiguous forest. Patches less than 150 acres are not of optimum value to forest interior birds. The Forest Focus Areas outside the Catskill Forest Preserve cover about 6% of the area underlain by the Marcellus Shale. However, the actual impacts on Marcellus development would affect less area for two reasons. First, only those portions of the Forest Focus Areas meeting the minimum patch size requirement would be subject to the aforementioned restrictions on surface disturbance. Second, even in areas where surface disturbance should be avoided, gas deposits could be accessed horizontally from adjacent areas. Given the horizontal reach of the wells, only about 2% of the subsurface areas would not be accessible.

7.4.1.3 Monitoring Changes in Habitat

The following mitigation measures are necessary to better understand and evaluate the impacts of habitat fragmentation on New York's wildlife from multi-pad horizontal gas wells and would be required as permit conditions for any applications seeking site disturbance in 150-acre portions of Forest Focus Areas and 30-acre portions of Grassland Focus Areas:

- Conduct pre-development surveys of plants and animals to establish baseline reference data for future comparison;[75]

- Monitor the effects of disturbance as active development proceeds and for a minimum of two years following well completion. Practice adaptive management as previously unknown effects are documented; and[76]

[73] Roberts and Norment 1999, Hoover et al. 1995, Robbins 1979.

[74] Rosenburg et al. 1999, Robinson et al. 1995.

[75] New Mexico Dept Game & Fish, 2007.

- Conduct test plot studies to develop more effective revegetation practices. Variables might include slope, aspect, soil preparation, soil amendments, irrigation, and seed mix composition.[77]

With the aforementioned measures in place, the significant adverse impacts on habitat from high-volume hydraulic fracturing would be partially mitigated.

7.4.2 Invasive Species

Chapter 26 of the Laws of New York, 2008, amended the ECL to create the New York Invasive Species Council[78,79] and define the Department's authority regarding control of invasive species in New York. The Council, co-lead by the Department and the Department of Agriculture and Markets (DAM), comprises the Department of Transportation (DOT), the Office of Parks, Recreation and Historic Preservation (OPRHP), the State Education Department (SED), the Department of State (DOS), the Thruway Authority, the New York State Canal Corporation, and the Adirondack Park Agency (APA).

The role of the Council includes identifying actions to prevent the introduction of invasive species, detect and respond rapidly to control populations of invasive species, monitor invasive species populations, provide for the restoration of native species and habitats that have been invaded, and promote public education on invasive species.[80]

Additionally, a comprehensive management plan is being developed which will address all taxa of invasive species in New York, with an emphasis on prevention, early detection and rapid response, and opportunities for control and restoration to prevent future damage. In accordance with ECL §9-1705(5)(c), the plan will incorporate the approved New York State Aquatic

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[76] New Mexico Dept Game & Fish, 2007.

[77] New Mexico Dept Game & Fish, 2007.

[78] ECL § 9-1707.

[79] The New York Invasive Species Council supplanted the Invasive Species Task Force that was established in 2003 to explore the invasive species issue and provide recommendations to the Governor and Legislature by November 2005. The task force's findings and recommendations are summarized in the "Final Report of the New York State Invasive Species Task Force," which is available at http://www.dec.ny.gov/docs/wildlife_pdf/istfreport1105.pdf.

[80] ECL §9-1705(5)(b).

Nuisance Species Management Plan, the Lake Champlain Basin Aquatic Nuisance Species Management Plan, and the Adirondack Park Aquatic Nuisance Species Management Plan.

The Council also prepared a report that described a regulatory system for non-native species[81] and included a four-tier system for preventing the importation and/or release of non-native animal and plant species. The system contains proposed lists of prohibited, regulated and unregulated species, and a procedure for the review of any non-native species that is not on the aforementioned lists before the use, distribution or release of such non-native species.

ECL §9-1709(2)(d) authorizes the Department to prohibit and actively eliminate invasive species at project sites regulated by the State. This responsibility falls within the purview of the Department's Division of Fish, Wildlife and Marine Resources.

7.4.2.1 Terrestrial

In order to mitigate the potential transfer of terrestrial invasive species from project locations associated with high-volume hydraulic fracturing, including well pads, access roads, and engineered impoundments for fresh water, the Department proposes that well operators be required to conduct all activities in accordance with the best management practices below. This would be reflected by a permit condition (see Appendix 10) requiring the preparation and implementation of an invasive species mitigation plan that would be included on all well permits where high-volume hydraulic fracturing is proposed.

Survey for the Presence of Invasive Species

Invasive species control is two-fold in that it involves both limiting the spread of existing invasive species and limiting the introduction of new invasive species. In order to accomplish these objectives, it is necessary to identify the types of invasive species which are present at a project site as well as map the locations and extent of any established population.

Therefore, the Department proposes to require that well operators submit, with the EAF Addendum for a single well or the first well proposed on a multi-well pad, a comprehensive survey of the entire project site, documenting the presence and identity of any invasive plant

[81] Final report – A regulatory system for non-native species. New York Invasive Species Council. 10 June 2010. http://www.dec.ny.gov/docs/lands_forests_pdf/invasive062910.pdf.

species. The survey should be conducted by an environmental consultant familiar with the invasive species in New York. This survey would establish a baseline measure of percent aerial coverage and, at a minimum, would be required to include the plant species identified on the Interim List of Invasive Plant Species in New York State.[82] A map (1:24,000) showing all occurrences of invasive species within the project site would also be required to be included with the survey as part of the EAF Addendum.

Field notes, photographs and GPS handheld equipment should be utilized in documenting any occurrences of invasive species and all such occurrences would be required to be clearly identified in the field with signs, flagging, and/or stakes prior to any ground disturbance. If the invasive species survey submitted with the EAF Addendum shows the presence of specific invasive species, consultation with the Department may be required prior to any ground disturbance.

Preventing the Spread of Invasive Species

- Prior to any ground disturbance, any invasive plant species encountered at the site should be stripped and removed. Cut plant materials, including roots and rhizomes, should be placed in heavy duty, 3-mil or thicker, black, contractor-quality plastic cleanup bags. The bags should then be securely tied and transported from the site to a proper disposal facility in a truck with a topper or cap, in order to prevent the spread or loss of the plant material during transport;

- Cut invasive plant species materials should not be disposed of into native cover areas;

- Machinery and equipment, including hand tools, used in invasive species affected areas would be required to be pressure-washed and cleaned with water (no soaps or chemicals) prior to leaving the invasive species affected area to prevent the spread of seeds, roots or other viable plant parts. This includes all machinery, equipment and tools used in the stripping, removal, and disposal of invasive plant species;

- Equipment or machinery should not be washed in any waterbody or wetland, and run-off resulting from washing operations should not be allowed to directly enter any water bodies or wetlands. Appropriate erosion control measures would be required be employed;

- Loose plant and soil material that has been removed from clothing, boots and equipment, or generated from cleaning operations would either be a) rendered incapable of any

[82] This list appears in Tables 6.4 and 6.5.

growth or reproduction or b) appropriately disposed of off-site. If disposed of off-site, the plant and soil material would be required to be transported in a secure manner;

Preventing New Invasive Species Introductions

- All machinery and equipment to be used in the construction of the proposed project location, including but not limited to trucks, tractors, excavators, and any hand tools, would be required to be washed with high pressure hoses and hot water prior to delivery to the project site to insure that they are free of invasive species;

- All fill and/or construction material (e.g. gravel, crushed stone, top soil, etc.) from offsite locations should be inspected for invasive species and should only be utilized if no invasive species are found growing in or adjacent to the fill/material source; and

- Only certified weed-free straw should be utilized for erosion control.

Restoration and Preservation of Native Vegetation

- Native vegetation should be reestablished and weed-free mulch should be used on bare surfaces to minimize weed germination;

- Only native (non-invasive) seeds or plant material should be used for re-vegetation during site reclamation. An appropriate native seed mixture should be selected based on pre-disturbance surveys;

- All seed should be from local sources to the extent possible and should be applied at the recommended rates to ensure adequate vegetative cover to prevent the colonization of invasive species;

- As part of site reclamation, re-vegetation should occur as quickly as possible at each project site;

- Any top soil brought to the site for reclamation activities should be obtained from a source known to be free of invasive species; and

- The site should be monitored for new occurrences of invasive plant species following partial reclamation. If new occurrences are observed, they should be treated with appropriate physical or chemical controls.

General

- Implementation of the above practices would be required to be in accordance with a site-specific and species-specific invasive species mitigation plan that includes seasonally appropriate specific physical and chemical control methods (e.g., digging to remove all roots, cutting to the ground, applying herbicides to specific plant parts such as stems or foliage, etc.). The invasive species mitigation plan would be required to be available to the Department upon request and available on-site for a Department inspector's review at any time that related activities are occurring;

- The well operator should assign an environmental monitor to check that all trucks, machinery and equipment have been washed prior to entry and exit of the project site and that there is no dirt or plant material clinging to the wheels, tracks, or undercarriage of the vehicles or equipment; and
- Any new invasive species occurrences found at the project location should be removed and disposed of appropriately.

The Department finds that with implementation of the aforementioned BMPs, significant adverse impacts from terrestrial invasive species would be mitigated to the maximum extent practicable.

7.4.2.2 Aquatic[83]

It is beneficial to the operators to implement water conservation and recycling practices because of the potential difficulties obtaining the large volumes of water needed for hydraulic fracturing. Most or all operators will recycle or reuse flowback water to reduce the need for fresh water.

It is possible that some unused fresh water may remain in a surface impoundment after drilling and hydraulic fracturing is completed. This is likely in circumstances where operators build large centralized surface impoundments to hold water for all drilling and hydraulic fracturing operations within a several mile radius. Unused water may be transported by truck or pipeline and discharged into tanks or surface impoundments for use at another drilling location. It also is possible that unused water could be transported and discharged at its point of origin with proper approval. Either of these options avoids the transfer of invasive species into a new habitat or watershed. Precautions would be required to be implemented, especially when water is stored in surface impoundments, to preclude the transfer of invasive species into new habitats or watersheds.

Unused fresh water also could be transported to a wastewater treatment facility for processing, although this is considered unlikely given the anticipated demand for water in the drilling and hydraulic fracturing process. As detailed in Section 7.1.8.1, flowback water cannot be taken to a publicly owned treatment works without the Department's approval. Standard treatment

[83] Alpha, 2009, p. 3-6 *et seq.*, and supplemented by DEC.

processes at waste water treatment plants, such as dissolved air flotation, have been shown to successfully remove biological particles and sediments that might harbor invasive species; however, the safest method to avoid transfer of invasive species is to not transfer water from one water body to another.

Regulatory protections exist to reduce the potential for the transfer of aquatic invasive species. Regulations and policies of SRBC and DRBC both address the transfer, reuse and discharge of water and SRBC requires appropriate treatment to prevent the spread of aquatic invasive species. Table 7.5 is a matrix of SRBC and DRBC regulations pertaining to transfer of invasive species. The regulations are identified that specifically address the transport of invasive or nuisance aquatic species. Other regulations in Table 7.5 do not specifically relate to invasive species, but the required actions and policies nonetheless may have the effect of reducing or eliminating their transport.

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

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

TABLE 7.5
Summary of Regulations Pertaining to Transfer of Invasive Species

Agency	Document		Article	Regulation Summary
SRBC	Federal Register, Vol 73, No. 247, Rules and Regulations		18 CFR Part 806.22,f,8	All flowback and produced fluids, including brines, must be treated and disposed of in accordance with applicable state and federal law.
SRBC	Regulation of Projects		18 CFR Part 806.24,b,3,c	For diversions into the SRB, must provide: (1) the source, amount, and location of the diverted water,and (2) the water quality classification, if any, of the SRBC discharge stream and the discharge location(s). (3) All applicable withdrawal or discharge permits or approvals must have been applied for or received, and must prove that the diversion will not result in water quality degradation that may be injurious to any existing or potential ground or surface water use.
SRBC	Regulation of Projects		18 CFR Part 801.3,b	The SRBC will require evidence that proposed interbasin transfers of water will not jeopardize, impair or limit the efficient development and management of the SRBC's water resources, or any aspects of these resources for in-basin use, or have a significant unfavorable impact on the resources of the basin and the receiving waters of the Chesapeake Bay.
SRBC	Regulation of Projects		18 CFR Part 801.3,c,1	Allocations, diversions, or withdrawals of water must be based on (1) the rights of landholders in any watershed to use the stream water in reasonable amounts and to have the stream flow not unreasonably diminished in quality or quantity by upstream use or diversion of water; and (2) on the maintenance of the historic seasonal variations of the flows into Chesapeake Bay.
SRBC	Regulation of Projects		18 CFR Part 806.23,2	The SRBC may deny or limit an approval if a withdrawal may cause significant adverse impacts to SRB water, including: lowering of groundwater or stream flow levels; rendering competing supplies unreliable; affecting other water uses; causing water quality degradation that may be injurious to any existing or potential water use; affecting any living resources or their habitat; causing permanent loss of aquifer storage capacity; or affecting low flow of perennial or intermittent streams.
SRBC	Federal Register, Vol 73, No. 247, Rules and Regulations		18 CFR Part 806.22,f,6	Flowback fluids or produced brines used for hydrofracturing must be separately accounted for, but will not be included in the daily use volume or be subject to the mitigation requirements of § 806.22 [b].
SRBC	Standard Docket Conditions Contained In Gas Well **Consumptive Water Use**	*	Item 10.	Unused water shall not be discharged back to the SRB waters without appropriate controls and treatment to prevent the spread of aquatic nuisance species.
SRBC	Regulation of Projects		18 CFR Part 806.25,b, 4	Industrial water users must evaluate and utilize applicable recirculation and reuse practices.
SRBC	Standard Docket Conditions Contained In Gas Well **Surface Water** Dockets		Item 4. (Not contained in all approvals)	Within ninety (90) days of this approval, the project sponsor shall submit a plan of study and a schedule for completion to conduct a survey and evaluate the potential impacts on the rare and protected freshwater mussels located in the Susquehanna River within the area of the withdrawal.
SRBC	Standard Docket Conditions Contained In Gas Well **Surface Water** Dockets		Item 5. (Not contained in all approvals)	This approval does not become effective until the SRBC is satisfied that the withdrawal has no adverse impacts to the rare and protected freshwater mussel species of concern.
SRBC	Standard Docket Conditions Contained In Gas Well **Surface Water** Dockets	*	Item 10.	Must report the method of water transport (tanker truck or pipeline) and show that all water withdrawn from surface water sources is transported, stored, injected into a well, or discharged with appropriate controls and treatment to prevent the spread of aquatic nuisance species.
DRBC	Water Code 18 CFR Part 410		2.20.2	The underground water-bearing formations of the DRB, their waters, storage capacity, recharge areas, and ability to convey water shall be preserved and protected.
DRBC	Water Code 18 CFR Part 410		2.20.3	Projects that withdraw underground waters must reasonably safeguard the present and future public interest in the affected water resources.
DRBC	Water Code 18 CFR Part 410		2.20.4	Withdrawals from DRB ground water are limited to the maximum draft of all withdrawals from a ground water basin, aquifer, or aquifer system that can be sustained without rendering supplies unreliable, causing long-term progressive lowering of ground water levels, water quality degradation, permanent loss of storage capacity, or substantial impact on low flows of perennial streams, unless the DRBC decides a withdrawal is in the public interest. In confined coastal plain aquifers, the DRBC may apply aquifer management levels, if any, established by a signatory state in determining compliance with criteria relating to "longterm progressive lowering of ground water levels."
DRBC	Water Code 18 CFR Part 410		2.20.5	The principal natural recharge areas of the DRB shall be protected from unreasonable interference. No recharge sources (ground or surface water) shall be polluted based on water quality standards promulgated by the DRBC or any of the signatory parties.
DRBC	Water Code 18 CFR Part 410		2.20.6	The DRB ground water resources shall be used, conserved, developed, managed, and controlled for the needs of present and future generations, so interference, impairment, penetration, or artificial recharge shall be subject to review and evaluation under the Compact.
DRBC	Water Code 18 CFR Part 410		2.10.1	The DRBC may acquire, operate and control projects and facilities for the storage and release of waters, for the regulation of flows and DRB surface and ground water supplies, for the protection of public health, stream quality control, economic development, improvement of fisheries, recreation, pollution dilution and abatement, the prevention of undue salinity and other purposes. No signatory party may permit any augmentation of flow to be diminished by the diversion of any DRB water during any period in which waters are being released from storage by the DRBC for the purpose of augmenting such flow, except in cases where such diversion is authorized by this compact, or by the DRBC pursuant to, or by the order of a court of competent jurisdiction.

Agency	Document	Article	Regulation Summary
DRBC	Water Code 18 CFR Part 410	2.30.2	The waters of the DRB are limited in quantity and to drought. The exportation of DRB water is discouraged. The DRB waters have limited assimilative capacity to accept substances without significant impacts. Wastewater import that would significantly reduce the assimilative capacity of the receiving DRB stream is discouraged and should be reserved for users within the DRB.
DRBC	Water Code 18 CFR Part 410	2.30.3	Consideration of the importation or exportation of water will be conducted pursuant to this policy and include assessments of the water resource and economic impacts of the project and of all alternatives to any water exportation or wastewater importation project.
DRBC	Water Code 18 CFR Part 410	2.30.4	The DRBC has jurisdiction over exportations and importations of water (Section 3.8 of the Compact, and inclusion within the Comprehensive Plan) as specified in the Administrative Manual - Rules of Practice and Procedure. The applicant shall address those of the items listed below as directed by the DRBC: A. efforts to develop or use and conserve outside resources; B. water resource, economic, and social impacts of each alternative, including the "no project" alternative; D. amount, timing and duration of the proposed transfer and its relationship to DRB hydrologic conditions, and impact on instream uses and downstream waste assimilation capacity; E. benefits to the DRB as a result of the proposed transfer; F. volume of the transfer and its relationship to other specified actions or Resolutions by the DRBC; G. the relationship of the transfer volume to all other diversions; H. other significant benefits or impairments to the DRB as a result of the proposed transfer.
DRBC	Water Code 18 CFR Part 410	2.30.6	The DRBC gives no credit toward meeting wastewater treatment requirements for wastewater imported into the Delaware Basin. Wasteload allocations assigned to dischargers will not include loadings attributable to wastewater importation.
DRBC	Water Code 18 CFR Part 410	2.200.1	DRB water quality will be maintained in a safe and satisfactory condition for...wildlife, fish and other aquatic life.
DRBC	Water Code 18 CFR Part 410	2.350.2	The DRBC will preserve and protect wetlands by: A. minimizing adverse alterations in the quantity and quality of the underlying soils and natural flow of waters that nourish wetlands; B. safeguarding against adverse draining, dredging or filling practices, liquid or solid waste management practices, and siltation; C. preventing the excessive addition of pesticides, salts or toxic materials arising from non-point source wastes; and D. preventing destructive construction activities.
DRBC	Water Code 18 CFR Part 410	2.400.2	The drought of record, which occurred in the period 1961-1967, shall be the basis for planning and development of facilities and programs for control of salinity in the Delaware Estuary.
DRBC	Water Code 18 CFR Part 410	3.10.3,A,1	The DRBC maintains the quality of interstate waters, where existing quality is better than the established stream quality objectives, unless such change is justifiable as a resul of necessary economic or social development or to improve significantly another body of water. The DRBC will require the highest degree of waste treatment practicable. No change will be considered which would be injurious to any designated present or future use.
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,b	There will be no measurable change in water quality except towards natural conditions in water that has high scenic, recreational, ecological, and/or water supply values. Waters with exceptional values may be classified as either **Outstanding Basin Waters (OBW) or Significant Resource Waters (SRW)**. OBW shall be maintained at their existing water quality. 2) SRW must not be degraded below existing water quality, although localized degradation of water quality may be allowed for initial dilution if the DRBC, after consultation with the state NPDES permitting agency, finds that the public interest warrants these changes, unless a mixing zone is allowed and then to the exten of the mixing zone designated as set forth in this section. If degradation of water quality is allowed for initial dilution purposes, the DRBC, will designate mixing zones for each point source and require the highest possible point source treatment levels necessary to limit the size and extent of the mixing zones. The dimensions of the mixing zone will be based upon an evaluation of (a) site specific conditions, including channel characteristics; (b) the cost and feasibility of treatment technologies; and (c) the design of the dis
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,c	1) Direct discharges of wastewater to **Special Protection Waters (SPW)** are discouraged. New wastewater treatment facilities and substantial alterations to existing facilities that discharge directly to SPW may be approved after the applicant has evaluated all nondischarge/ load reduction alternatives and is unable to implement these alternatives because of technical and/or financial infeasibility. 2) New wastewater treatment facilities and substantial alterations to existing facilities within the drainage area of SPW may be approved after the applicant fully evaluated all natural treatment alternatives and is unable to implement them because of technical and/or financial infeasibility. **For both 1) and 2)** above, the applicant will consider alternatives to all loadings – both existing and proposed – in excess of actual loadings at the time of SPW designation. 3) New wastewater treatment facilities and substantial alterations to existing facilities discharging directly to SRW may be approved only following a determination that the project is in the public interest as that term is defined in Section 3.10.3.A.2.a.5 4) The general number, location and size of future wastewater treatment facilities discharging to OBW (if ar
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,d	Addresses emergency systems (standby power facilities, alarms, emergency management plans) for wastewater treatment facilities discharging to SPW. Emergency management plans shall include an emergency notification procedure covering all affected downstream users. The minimum level of wastewater treatment for new wastewate treatment facilities and substantial alterations to existing wastewater treatment facilities that discharge directly to OBW or SRW will be **Best Demonstrable Technology (BDT)** (See rule for chemical analyses results that define BDT.) BDT may be superseded by applicable federal, state or DRBC criteria that are more stringent. BDT for disinfection - ultraviolet light disinfection or an equivalent disinfection process that results in no harm to aquatic life, does not produce toxic chemical residuals, and results in effective bacterial and viral destruction. DRBC may approve effluent trading on a voluntary basis between point sources within the same watershed or between the same Interstate or Boundary Control Points to achieve no measurable change to existing water quality. Regulation discusses facilities within drainage areas of SPW and discharges to OBW and SRW and lists water quality control points and the analyses parameters.
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,e	1) Projects subject to review under Section 3.8 of the Compact that are located in the drainage area of SPW must submit for approval a Non-Point Source Pollution Control Plan that controls the new or increased non-point source loads generated within the portion of the project's service area which is also located within the drainage area of SPW The plan will state which BMPs must be used to control the non-point source loads. RULE DISCUSSES trade-off plans in detail. It discusses: projects located above major

Agency	Document	Article	Regulation Summary
			surface water impoundments; projects located in municipalities that have adopted and are actively implementing non-point source/stormwater control ordinances, projects located in watersheds where the applicable state environmental agency, county government, and local municipalities are participating in the development of a watershed plan. 2) Approval of a new or expanded water withdrawal and/or wastewater discharge project will be subject to the condition that any new connection to the project system only serve an area(s) regulated by a non-point source pollution control plan which has been approved by the DRBC. 3) Future plans for SPWs non-point source control regulations
DRBC	Water Code 18 CFR Part 410	3.10.3B	DRB waters will not contain substances attributable to municipal, industrial, or other discharges in concentrations or amounts sufficient to preclude the protection of specified water uses. a. The waters shall be substantially free from unsightly or malodorous nuisances due to floating solids, sludge deposits, debris, oil, scum, substances in concentrations or combinations which are toxic or harmful to human, animal, plant, or aquatic life, or that produce color, taste, odor of the water, or taint fish or shellfish flesh. b. The concentration of total dissolved solids, except intermittent streams, shall not exceed 133 percent of background. In no case shall concentrations of substances exceed those values given for rejection of water supplies in the United States Public Health Service Drinking Water Standards.
DRBC	Water Code 18 CFR Part 410	3.10.3C	The DRBC designates numerical stream quality objectives for the protection of aquatic life for the Delaware River Estuary (Zones 2 through 5) which correspond to the designated uses of each zone. Aquatic life objectives for the protection from both acute and chronic effects are herein established on a pollutant-specific basis. (See RULE)
DRBC	Water Code 18 CFR Part 410	3.10.3D	The DRBC designates numerical stream quality objectives for the protection of human health for the Delaware River Estuary (Zones 2 through 5) which correspond to the designated uses of each zone. Stream quality objectives for protection from both carcinogenic and systemic effects are herein established on a pollutant-specific basis. (See RULE)
DRBC	Water Code 18 CFR Part 410	3.10.4,A	All wastes shall receive a minimum of secondary treatment, regardless of the stated stream quality objective.
DRBC	Water Code 18 CFR Part 410	3.10.4,B	Wastes (exclusive of stormwater bypass) containing human excreta or disease producing organisms shall be effectively disinfected before being discharged into surface bodies of water as needed to meet applicable DRBC or State water quality standards.
DRBC	Water Code 18 CFR Part 410	3.10.4,C	Effluents shall not create a menace to public health or safety at the point of discharge.
DRBC	Water Code 18 CFR Part 410	3.10.4,D	Lists discharge contaminant limits.
DRBC	Water Code 18 CFR Part 410	3.10.4,E	Where necessary to meet the stream quality objectives, the waste assimilative capacity of the receiving waters shall be allocated in accordance with the doctrine of equitable apportionment.
DRBC	Water Code 18 CFR Part 410	3.10.4,F	1. Discharges to intermittent streams may be permitted by the DRBC only if the applicant can demonstrate that there is no reasonable economical alternative, the project is environmentally acceptable, and would not violate the stream quality objectives set forth in Section 3.10.3B.1.a. 2. Discharges to intermittent streams shall be adequately treated to protect stream uses, public health and ground water quality, and prevent nuisance conditions.
DRBC	Water Code 18 CFR Part 410	3.10.5,E	The DRBC will consider requests to modify the stream quality objectives for toxic pollutants based upon site-specific factors. Such requests shall provide a demonstration of the site-specific differences in the physical, chemical or biological characteristics of the area in question, through the submission of substantial scientific data and analysis. The demonstration shall also include the proposed alternate stream quality objectives. The methodology and form of the demonstration shall be approved by the DRBC.
NYSDEC	6 NYCRR Part 608	608.9	(a) Water quality certifications required by Section 401 of the Federal Water Pollution Control Act, Title 33 United States Code 1341(see subdivision (c)of this Section). Any applicant for a federal license or permit to conduct any activity, including but not limited to the construction or operation of facilities that may result in any discharge into navigable waters as defined in Section 502 of the Federal Water Pollution Control Act (33 USC 1362), must apply for and obtain a water quality certification from the department.The applicant must demonstrate compliance with Sections 301-303, 306 and 307 of the Federal Water Pollution Control Act (See RULE.)

* Connotes the indicated regulation pertains directly to invasive or nuisance species. All other regulations reference practices, methods, and actions that are not specifically targeted at reducing or eliminating the transport of invasive species, but nonetheless may indirectly address the issue.

The measures and protocols adopted by the SRBC and DRBC help to address the potential for transfer of invasive species associated with water use for high-volume hydraulic fracturing. These protocols, however, are not explicit nor do they apply to the entire area subject to natural gas activities covered by this SGEIS. Thus, in addition to the requirements of SRBC and DRBC, the Department recommends that the following best management practices be instituted and incorporated into the required invasive species mitigation plan to reduce the risk of transferring invasive species from both the exportation and importation of fresh water. These best management practices target two specific pathways for the transfer of invasive species, namely the vehicles and equipment used to transfer the fresh water and the fresh water being moved between sites and/or discharged.

Best Management Practices for vehicles and equipment:

1. Inspect all vehicles and equipment including trucks, trailers, pumps, hoses, screens, gates, etc. prior to deployment to new site;

2. Drain all hoses and equipment at collection site after use;

3. Clean all mud, vegetation, organisms and debris and dispose on site if the contaminants originated at site; dispose in 3 mil trash bags and dispose in trash if contaminants were transported from another site;

4. When withdrawing water from waters at multiple surface water locations on a single water body, begin at furthest upstream collection point;

5. Before moving to another water body, decontaminate equipment that has come in contact with surface water using appropriate protocols outlined below:

    - Pressure wash with 140º F water at contact point for 3 minutes or disinfect with 200 ppm (0.5 oz/gallon) chlorine for 10 minute contact time; keep disinfection solution from entering surface waters; and

    - Dry (regardless of treatment).

6. Well operators should provide truck and equipment drivers and operators with clear instructions, inspection checklists identifying areas on the vehicles or equipment most likely to harbor invasive species, and specifications and protocols for cleaning and disinfection; and

7. Document all inspections, cleaning and disinfection activities in a log that would be required to be maintained by the well operator and made available to the Department upon request. At a minimum this log would be required to include:

   - Dates and times of all inspection and cleaning/disinfection activities;
   - Identification of the vehicles and equipment inspected and cleaned/disinfected; and
   - Information regarding the method of cleaning/disinfection.

Best Management Practices for fresh water:

1. Transport unused fresh water via truck or pipeline to other drilling locations where it can be discharged into tanks or for subsequent use; and

2. If fresh water cannot be used at another drilling location, dispose of unused fresh water over land (not in surface water or in manner that drains directly to surface water), preferably in same drainage area as collected, and using appropriate erosion control measures.

The Department finds that with the institution of the above-referenced BMPs, significant adverse impacts from aquatic invasive species would be mitigated to the maximum extent practicable.

7.4.3 Protecting Endangered and Threatened Species

Prospective project sites should be screened against the Department's Natural Heritage Database to determine if endangered or threatened species are known to occur within the vicinity. The best method for reducing impacts to these species is to avoid siting projects in locations and habitats known to be utilized by endangered and threatened wildlife.

Whenever possible, impacts to endangered and threatened animal species should be avoided. The process for accomplishing this is laid out below:

- As part of the EAF, the project proponent should do at least one of the following to screen the project site for potential endangered and threatened animal species:
- Request a screening from the New York Natural Heritage Program;
- Self-screen utilizing the Nature Explorer and Environmental Resource Mapper web tools on the Department's website; or
- Conduct site-specific surveys to determine if endangered and threatened animal species are present at the project site;
- If any endangered and threatened animal species are found to occur in the vicinity of the project site, the project proponent should consult with the Regional Department Natural Resources Office;
- Regional Department staff can work with project proponent to identify how species may be affected;
- Project proponent changes the location of the proposed project or otherwise modifies the project to avoid any potential "take" of a protected species identified by Department staff; and
- If the "take" of an endangered and threatened species is deemed to be unavoidable, the project proponent would be required to apply for an Incidental Take Permit.

The specific procedure for applying for the Incidental Take Permit is set forth in the Department's regulations at 6 NYCRR Part 182 and is summarized below:

- The applicant develops an endangered or threatened species mitigation plan;
- The applicant develops an implementation agreement that affirms how the mitigation plan will be accomplished;
- The Department reviews the mitigation plan and implementation agreement to determine if it meets applicable regulatory criteria; and
- If the Department approves the mitigation plan and implementation agreement and all other regulatory criteria are met, then an Incidental Take Permit can be issued, subject to the requisite SEQRA review.

The Department finds that with the implementation of the above measures, impacts on protected endangered and threatened species would be minimized.

7.4.4 Protecting State-Owned Land

As discussed in Section 6.4.4, the following issues are of significant concern as they relate to State-owned forests, wildlife management areas and parklands, and the potential impacts upon them (See also Sections 6.4.1 and 7.4.1):

- Forest fragmentation: Because of their size and long-term ownership, the specified state-owned public lands are integral to providing continuous interior forest habitat conditions and are protected from industrial development. The road systems needed to conduct drilling and fracturing operations represent significant potential impacts to this important habitat type;

- Grassland fragmentation: Because of their size and long-term ownership, the specified state-owned lands are integral to providing grassland habitat conditions and are protected from industrial development. The road systems needed to conduct drilling and fracturing operations represent significant potential impacts to this important habitat type;

- Public recreation: The level of truck traffic associated with horizontal drilling and high volume hydraulic fracturing, the presence of drilling rigs and compressor complexes, and the need to light well pads during drilling and fracturing operations would be likely to create significant impacts on public recreation opportunities during the construction, drilling and fracturing phases of development; and

- Wildlife impacts: Increased light and noise levels would be likely to have significant impacts on local wildlife populations, including impacts on breeding, feeding and migration. The activities creating these impacts could take place for up to three years at any one site, depending on how many wells are drilled from a particular well pad. The local wildlife populations could take years or even decades to recover.

As an example for one natural gas reservoir that could be developed by high-volume hydraulic fracturing, State Forests, Wildlife Management Areas and State Parks comprise less than 6% of the area underlain by the Marcellus Shale in New York State. (As stated in Chapter2, drilling will not occur on Forest Preserve lands because the State Constitution prevents their being leased or sold.) Acknowledging that there will likely be physical, technological, ownership and leasing impediments to reaching all areas under State-owned forests, wildlife management areas and parklands, it is still likely that less than 3% of the Marcellus Shale formation would be rendered unavailable by prohibiting horizontal drilling and high-volume hydraulic fracturing surface disturbance on these lands.

In order to ensure that the State fulfills the purposes for which State Forests and State Wildlife Management Areas were created, no surface disturbance associated with horizontal drilling and high-volume hydraulic fracturing would be permitted on State Forests or Wildlife Management Areas. This prohibition does not include accessing subsurface resources located within these areas from adjacent private lands. With the surface disturbance restriction in place, the Department concludes that impacts to the specified state-owned lands from high-volume hydraulic fracturing would be minimized. Current OPRHP policy would impose a similar restriction on State Parks.

7.5 Mitigating Air Quality Impacts

This section identifies mitigation measures which are necessary, or may be necessary, to achieve compliance with Federal and State air quality standards, State air quality guidelines and State and Federal regulations. A detailed discussion of the Department's air quality impact assessment and analysis of applicable State and Federal regulatory requirements and regional air quality considerations which give rise to these mitigation measures is presented in Section 6.5. This section focuses on the following four points. First, the section identifies pollution control measures required to ensure compliance with ambient air quality standards for criteria air pollutants and State ambient air thresholds for toxic pollutants. This information is discussed in detail in Section 6.5.2 and, therefore, is included here in summary form. Second, this section includes a more detailed discussion of pollution control techniques required pursuant to State and Federal regulations for specific pollutants, such as NO_x, where emissions would be affected by the type of equipment and fuel to be used. The Department will address the different approaches, including various operational scenarios and equipment which can be used to achieve compliance. Third, this section summarizes the total suite of mitigation measures for well pad operations. Fourth, this section outlines an approach to mitigate formaldehyde emissions from the compressor station.

7.5.1 Mitigation Measures Resulting from Regulatory Analysis (Internal Combustion Engines and Glycol Dehydrators)

This section outlines the potential mitigation measures which would be best suited for given types of engine and fuel combinations to control NO_x; the use of ULSF fuel in diesel engines to control sulfur oxide emissions; and mitigation measures for glycol dehydrators. Section 7.5.2 identifies SCR as the NO_x control measure recommended for diesel engines as a result of the review of manufacturer's information and current use based on the detailed dispersion modeling assessment in Section 6.5.2. In addition, based on the modeling analysis, particulate traps are deemed the control technology of choice for certain tier diesel engines. Section 7.5.3 outlines all mitigation measures deemed necessary to assure compliance with Federal and State air quality standards. State air quality guidelines and Federal and State regulations are detailed in Section 6.5.

7.5.1.1 Control Measures for Nitrogen Oxides-NO_x

Control Techniques for Natural Gas Engines

Three generic control techniques have been developed for reciprocating engines: 1) parametric controls (timing and operating at a leaner air-to-fuel ratio); 2) combustion modifications such as advanced engine design for new sources or major modification to existing sources (clean-burn cylinder head designs and pre-stratified charge combustion for rich-burn engines); and 3) post-combustion catalytic controls installed on the engine exhaust system. Post-combustion catalytic technologies include SCR for lean-burn engines, NSCR for rich-burn engines, and CO oxidation catalysts for lean-burn engines. For example, the off-site compressors will be required to use an oxidation catalyst.

Control Techniques for 4-Cycle Rich-Burn Engines

Nonselective Catalytic Reduction (NSCR) - This technique uses the residual hydrocarbons and CO in the rich-burn engine exhaust as a reducing agent for NO_x. In NSCR, hydrocarbons and CO are oxidized by O_2 and NO_x. The excess hydrocarbons, CO and NO_x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_x to N_2. NO_x reduction efficiencies are usually greater than 90 %, while CO reduction efficiencies are approximately 90 %.

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 % or less. This includes 4-stroke rich-burn, naturally aspirated engines and some 4-stroke rich-burn, turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective NO_x reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 %. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.

Pre-Stratified Charge - Pre-stratified charge combustion is a retrofit system that is limited to 4-stroke carbureted natural gas engines. In this system, controlled amounts of air are introduced into the intake manifold in a specified sequence and quantity to create a fuel-rich and fuel-lean zone. This stratification provides both a fuel-rich ignition zone and rapid flame cooling in the fuel-lean zone, resulting in reduced formation of NO_x. A pre-stratified charge kit generally contains new intake manifolds, air hoses, filters, control valves, and a control system.

Control Techniques for Lean-Burn Reciprocating Engines

Selective Catalytic Reduction (SCR) - SCR is a post-combustion technology that has been shown to effectively reduce NO_x in exhaust from lean-burn engines. An SCR system consists of an ammonia storage, feed, and injection system, and a catalyst and catalyst housing. SCR systems selectively reduce NO_x emissions by injecting ammonia (either in the form of liquid anhydrous ammonia or aqueous ammonium hydroxide) into the exhaust gas stream upstream of the catalyst. NO_x, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. For the SCR system to operate properly, the exhaust gas would be within a particular temperature range (typically between 450° F and 850° F). The temperature range is dictated by the catalyst (typically made from noble metals, base metal oxides such as vanadium and titanium, and zeolite-based material). Exhaust gas temperatures greater than the upper limit (850º F) will pass the NO_x and ammonia unreacted through the catalyst. Ammonia emissions, called NH_3 slip, are a key consideration when specifying a SCR system. SCR is most suitable for lean-burn engines operated at constant loads, and can achieve efficiencies as high as 90 %. For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.

Catalytic Oxidation - Catalytic oxidation is a post-combustion technology that has been applied, in limited cases, to oxidize CO in engine exhaust, typically from lean-burn engines. As previously mentioned, lean-burn technologies may cause increased CO emissions. The application of catalytic oxidation has been shown to effectively reduce CO emissions from lean-burn engines. In a catalytic oxidation system, CO passes over a catalyst, usually a noble metal, which oxidizes the CO to CO_2 at efficiencies of approximately 70 % for two-stroke lean-burn engines and 90 % for 4-stroke lean-burn engines.

Control Techniques for Diesel and Dual-Fuel Engines

The most common NO_x control technique for diesel and dual-fuel engines focuses on modifying the combustion process. However, post-combustion techniques, such as SCR and NSCR, are currently also available. Controls for CO have been partly adapted from mobile sources.

Combustion modifications include injection timing retard (ITR), pre-ignition chamber combustion (PCC), air-to-fuel ratio adjustments, and de-rating. Injection of fuel into the cylinder of a CI engine initiates the combustion process. Retarding the timing of the diesel fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. Increasing the volume lowers the combustion temperature and pressure, thereby lowering NO_x formation. ITR reduces NO_x from all diesel engines; however, the effectiveness is specific to each engine model. The amount of NO_x reduction with ITR diminishes with increasing levels of retard.

Improved swirl patterns promote thorough air and fuel mixing and may include a pre-combustion chamber (PCC). A PCC is an antechamber that ignites a fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC results in improved mixing and complete combustion of the lean air/fuel mixture, which lowers combustion temperature, thereby reducing NO_x emissions. The air-to-fuel ratio for each cylinder can be adjusted by controlling the amount of fuel that enters each cylinder. At air-to-fuel ratios less than stoichiometric (fuel-rich), combustion occurs under conditions of insufficient oxygen which causes NO_x to decrease because of lower oxygen and lower temperatures. Derating involves restricting the engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures, thereby lowering NO_x formation rates.

SCR is an add-on NO_x control placed in the exhaust stream following the engine and involves injecting ammonia (NH_3) into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form water and nitrogen. The effectiveness of SCR depends on fuel quality and engine duty cycle (load fluctuations). Contaminants in the fuel may poison or mask the catalyst surface causing a reduction or termination in catalyst activity. Load fluctuations can cause variations in exhaust temperature and NO_x concentration which can create problems with the effectiveness of the SCR system.

NSCR is often referred to as a three-way conversion catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC and the system involves placing a catalyst in the exhaust stream of the engine. The reaction requires that the O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios.

7.5.1.2 Control Measures for Sulfur Oxides - SO_x

Sulfur oxide emissions are a function of only the sulfur content in the fuel rather than any combustion variables. During the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2. The oxidation of SO_2 creates sulfur trioxide (SO_3), which reacts with water to create sulfuric acid (H_2SO_4), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to create sulfates, which are fine particulates that contribute to PM-10 and visibility reduction. Sulfur oxide emissions also contribute to corrosion of the engine parts.

Past communications with representatives of natural gas producer Chesapeake Energy indicated contractors that provide approximately 80% of the diesel rigs to the industry are using ultra low sulfur fuel (ULSF, 15ppm) because of the reduced availability of the alternative low sulfur fuel. Industry has identified the use of ULSF for all engines as a mitigation measure in their Information Report in response to Department requests.

The final EPA regulation at 40 CFR Part 63 Subpart ZZZZ (Engine MACT rule) described in Appendix 17 will mandate the use of ultra low sulfur fuel (ULSF). Accordingly, ULSF is being required for all engines to be used in New York Marcellus Shale activities.

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

40 CFR Part 63, Subpart HH imposes specific control requirements on TEG dehydrator units. Area source TEG dehydration units with natural gas throughput and benzene emission rates above the cutoff levels described in Section 6.5.1.2, must be connected, through a closed vent system, to one or more emission control devices. The control devices must: 1) reduce HAP emissions by 95 % or more (generally by a condenser with a flash tank); or 2) reduce HAP emissions to an outlet concentration of 20 ppm by volume (ppmv) or less (for combustion devices); or 3) reduce benzene emissions to a level less than 1.0 Tpy. As an alternative to complying with these control requirements, pollution prevention measures, such as process modifications or combinations of process modifications and one or more control devices that reduce the amount of HAP generated, are allowed provided that they achieve the same required emission reductions.

Area source TEG dehydration units with natural gas throughput and benzene emission rates above the cutoff levels described in Section 6.5.1.2, must reduce emissions by lowering the glycol circulation rate to less than or equal to an optimum rate. The optimum rate is determined by the following equation:

$$\text{LOPT} = 1.15 * 3.0 \frac{\text{gal TEG}}{\text{lb } H_2O} * \frac{\{F*(I - O)\}}{\{24\text{hr/day}\}}$$

Where:
LOPT = Optimal circulation rate, gal/hr.
F = Gas flowrate (MMSCF/D).
I = Inlet water content (lb/MMscf).
O = Outlet water content (lb/MMscf).

The constant 3.0 gal TEG/lb H_2O is the industry accepted rule of thumb for a TEG-to-water ratio. The constant 1.15 is an adjustment factor included for a margin of safety.

All glycol dehydrator units used at the well pad will be required to assure compliance with the 1 Tpy benzene emission limit using the above equation and necessary data and, in the event of wet gas, apply a condenser to assure such compliance.

7.5.2 Mitigation Measures Resulting from Air Quality Impact Assessment and Regional Ozone Precursor Emissions

The modeling analysis conducted and described in Section 6.5.2 concluded that most of the air quality standards and ambient thresholds will be met under the operations scenarios described by industry, including certain self-imposed restrictions on these operations. For example, industry has committed to: 1) limiting the number of wells to be drilled and completed per pad and per year to a maximum of four; 2) not operate drilling and hydraulic fracturing engines simultaneously at a single well pad; and 3) limit the amount of gas to be vented and flared per well. Even with these restrictions, however, certain air quality standards and ambient thresholds are projected to be exceeded for certain pollutants and, therefore, further mitigation measures are necessary. Section 6.5.2 details the specific pollutants of concern and the associated additional mitigation measures necessary to achieve standards compliance. For the mitigation measures necessary for the drilling and hydraulic fracturing engines, the review process and analysis conducted to support the specific control techniques recommended by the Department is also detailed.

In summary, the Department has determined that the modeling results support the following conclusions for the necessary mitigations which would be necessary for ambient standards compliance:

1) In order to meet the annual benzene ambient guideline concentration (AGC) due to the glycol dehydrator emission, the stack height needs to be a minimum of 30 feet even with the benzene emission limit of 1 Tpy;

2) The gas venting has to use a minimum stack height of 30 feet if "sour" gas is encountered in order to meet the 1-hour standard for H_2S;

3) The off-site compressor must have a minimum stack height of 25 feet, in addition to the oxidation catalyst required by regulation, in order to meet the formaldehyde annual threshold; and

4) Certain EPA "Tier" drilling and hydraulic fracturing engines will not be allowed for use in New York Marcellus activities, while others must be equipped with particulate traps and SCR controls.

Section 6.5.2.6 details measures required for specific tiers of engines. With respect to these specific measures for engines, industry is allowed to provide alternative measures which can demonstrate the equivalent emission reductions and standards compliance. In addition to these measures, based on the modeling results, additional controls to reduce NO_x emissions might be necessary in the future to address the Ozone NAAQS SIP requirements. The full set of control measures resulting from the regulatory and modeling assessments are provided in Section 6.5.5 and are repeated in the next section for convenience.

7.5.3 Summary of Mitigation Measures to Protect Air Quality

7.5.3.1 Well Pad Activity Mitigation Measures

The necessary control measures resulting from the air quality assessments will be imposed on the well pad activities through the well permitting process, as described in Section 6.5.5. Based on industry's self-imposed limitations on operations and Department's determination of conditions necessary to avoid or mitigate adverse air quality impacts from the well drilling, completion and production operations, the following restrictions must be imposed in the well permitting process:

- The diesel fuel used in drilling and hydraulic fracturing engines will be limited to ULSF with a maximum sulfur content of 15 ppm;

- Drilling and fracturing engines will not be operated simultaneously at the single well pad;

- The maximum number of wells to be drilled and completed annually or during any consecutive 12-month period at a single pad will be limited to four;

- The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control devise to limit the benzene emissions to one ton/year;

- Condensate tanks used at the well pad shall be equipped with vapor recovery systems to minimize fugitive VOC emissions;

- During the flowback phase, the venting of gas from each well pad will be limited to a maximum of 5 MMscf during any consecutive 12-month period. If "sour" gas is encountered with detected hydrogen sulfide emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m);

- During the flowback phase, flaring of gas at each well pad will be limited to a maximum of 120 MMscf during any consecutive 12-month period;

● Wellhead compressors will be equipped with NSCR controls;

● No uncertified (i.e., EPA Tier 0) drilling or hydraulic fracturing engines will be used for any activity at the well sites;

● The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both particulate traps (CRDPF) and SCR controls. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence; and

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

The EAF Addendum will require information regarding stack heights. If stack heights shorter than those specified in Table 7.6 are proposed, then information must be attached to the EAF Addendum which demonstrates that other control measures will effectively prevent exceedances for the listed pollutants.

Table 7.6 - Required Well Pad Stack Heights to Prevent Exceedances

Equipment	Pollutant	Stack Height
Flowback vent	H_2S	30 feet NOTE: not required if previous drilling at the same pad has demonstrated that H_2S is not present
Glycol dehydrator	Benzene	30 feet NOTE: Subpart HH compliance as described in Section 7.5.1.3 is also required.

7.5.3.2 Mitigation Measures for Off-Site Gas Compressors

As concluded in Sections 6.5.1.9 and 6.5.5, any off-site compressor "stations" will require a case by case air permit review pursuant to the Department's air permitting regulations. Thus, all necessary control measures, such as the stack height necessary to avoid exceedances of the annual formaldehyde, will be determined for each compressor during the application review process. From the regulatory requirements described in Section 6.5.1, an oxidation catalyst will be required to reduce the emissions of CO, VOCs and formaldehyde in all instances.

7.6 Mitigating GHG Emissions

Potential GHG emissions are discussed in Section 6.6 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 carbon dioxide (CO_2) and methane (CH_4) as both short tons and as carbon dioxide equivalents (CO_2e) expressed in short tons for expected exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. The real benefit of the emission estimates comes not with quantifying possible emissions but from the identification and characterization of likely major sources of CO_2 and CH_4 during the anticipated operations. Identification and understanding of the key contributors of GHGs allows mitigation measures and future efforts to be efficiently focused. The following sections discuss possible mitigation measures for limiting GHGs, with particular emphasis on CH_4 because of its Global Warming Potential (GWP).

7.6.1 General

EPA's Natural Gas STAR Program is a flexible, voluntary partnership that encourages oil and natural gas companies – both domestically and abroad – to adopt cost-effective technologies and practices that improve operational efficiency and reduce emissions of CH_4, a potent greenhouse gas and clean energy source.[84] Natural Gas STAR partners can implement a number of voluntary activities to reduce GHG emissions from both exploration and production activities. The Department strongly encourages active participation in the program. Therefore, an example

[84] http://www.epa.gov/gasstar/.

of a measure that could be included in a greenhouse gas emissions impacts mitigation plan includes:

- Proof of participation in the EPA's Natural Gas STAR Program to reduce methane emissions (see Appendices 24 and 25)[85]

7.6.2 Site Selection

Site selection directly impacts the number of rig and equipment mobilizations needed to develop a well pad or area. Well operators can limit the generation of CO_2 by limiting vehicle miles traveled (VMT) and fuel consumption. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- Drilling as many wells as possible on a pad with one rig move;
- Spacing wells for efficient recovery of natural gas;
- Hydraulic fracturing as many wells as possible on a pad with one equipment move; and
- Planning for efficient rig and fracturing equipment moves from one pad to another.

7.6.3 Transportation

Transportation related to sourcing of equipment and materials, including disposal, was identified as a potential contributor of CO_2 emissions. Well operators can limit the generation of CO_2 by limiting VMT and fuel consumption. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- Sourcing personnel and equipment from locations within the State or region to minimize the travel distance;
- Using materials that are extracted and/or manufactured within the State or region to minimize the shipping distance;
- Recycling fluids at in-state facilities;
- Disposal or processing wastes at in-state facilities including disposal wells; and

[85] http://www.epa.gov/gasstar/join/index.html.

- Using efficient transportation engines.

7.6.4 Well Design and Drilling

Well operators can limit GHG emissions during well drilling operations by effectively designing drilling programs. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- Extending each lateral wellbore as far as technically and legally possible to reduce the total number of wells required within a spacing unit;
- Spacing the lateral wellbores for efficient recovery of natural gas;
- Re-using drilling fluids;
- Drilling overbalanced to limit/prevent venting and/or flaring of CH_4;
- Using materials with recycled content (e.g., well casing, drilling fluids);
- Using efficient rig engines;
- Using efficient air compressor engines for drilling;
- Using efficient exterior lighting;
- Ensuring all flow connections are tight and sealed;
- Flaring methane instead of venting; and
- Performing leak detection surveys and taking corrective actions.

7.6.5 Well Completion

Well completion activities primarily contribute to GHG emissions from the internal combustion engines required for hydraulic fracturing and flaring operations during the flowback period. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- Re-using flowback water;
- Using materials with recycled content (e.g., hydraulic fracturing fluids);
- Using efficient hydraulic fracturing pump engines;

- Using efficient exterior lighting;
- Limiting flaring during the flowback phase by using REC equipment (see Appendix 25);
- If allowed by the PSC, constructing gathering lines so that the first well on a pad can initially be flowed into a sales line;
- Ensuring all flow connections are tight and sealed;
- Flaring methane instead of venting; and
- Performing leak detection surveys and taking corrective actions.

Two years after the completion date of the first well drilled and completed under the SGEIS, the Department would analyze the actual usage of RECs in New York, and examine existing conditions relative to industry's development of the Marcellus Shale and other low-permeability gas reservoirs, and PSC's position on the timing of pipeline installation as discussed in Chapter 8. At the same time, the Department would evaluate a possible additional REC requirement under certain circumstances through a new supplementary permit condition for high-volume hydraulic fracturing.

7.6.6 Well Production

As mentioned above, compared to any of the aforementioned operational phases, the ongoing production phase of any given well is the most significant period and contributor of GHGs, especially CH_4. Natural gas compressors which run virtually around-the-clock, produce both CO_2 and CH_4 emissions. Equipment required to process produced natural gas, specifically the glycol dehydrators (i.e., vents & pumps) and pneumatic devices, generate CH_4 emissions during normal production operations. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- Implementing EPA's Natural Gas STAR BMPs including below;[86]
- Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry;[87]

[86] http://www.epa.gov/gasstar/tools/recommended.html.

[87] http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf.

- Reducing Methane Emissions from compressor rod packing systems;[88]
- Reducing emissions when taking compressors off-line;[89]
- Replacing Glycol Dehydrators with Desiccant Dehydrators;[90]
- Replacing gas-assisted glycol pumps with electric pumps;[91]
- Optimizing glycol circulation and installing flash tank separators in glycol dehydrators;[92]
- Using efficient compressor engines;
- Using efficient line heaters;
- Using efficient glycol dehydrators;
- Re-using production brines;
- Ensuring all flow connections are tight and sealed;
- Performing leak detection surveys and taking corrective actions;
- Using efficient exterior lighting; and
- Using solar-powered telemetry devices.

7.6.7 Leak and Detection Repair Program

Because the production phase is the greatest contributor of GHGs and in an effort to mitigate VOC and methane leaks during this phase, the Department proposes to require, via permit condition and/or regulation, a Leak Detection and Repair Program would include as part of the operator's greenhouse gas emissions impacts mitigation plan which is required for any well subject to permit issuance under the SGEIS. In accordance with the corresponding plan developed by the operator to meet the Leak Detection and Repair Program's below minimum

[88] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

[89] http://www.epa.gov/gasstar/documents/ll_compressorsoffline.pdf.

[90] http://www.epa.gov/gasstar/documents/ll_desde.pdf.

[91] http://www.epa.gov/gasstar/documents/ll_glycol_pumps3.pdf.

[92] http://www.epa.gov/gasstar/documents/ll_flashtanks3.pdf.

requirements, an annual report for the calendar year would be completed by March 31 of each following year. Each annual report would be retained by the site owner for a minimum period of 5 years and would be made available to the Department upon request. The report would include the inspection results of the inspections and repairs completed and an explanation for any repairs that were not completed. The report would be accompanied by the certification of a company official that all repairs completed were in accordance with company policies and the requisite plan, and include a schedule for completion of repairs for any remaining leaks identified in the report. In addition, based on the leak history of a site, the report would include an evaluation and determination of the adequacy of the existing inspection procedures and schedule or a plan to modify existing procedures and/or increase the number of inspections in the current and future years. The Leak Detection and Repair Program may be modified at the operator's discretion provided it continues to meet the minimum requirements of the SGEIS.

The Leak Detection and Repair Program within the greenhouse gas emissions impacts mitigation plan would contain the following minimum requirements.

- There would be an ongoing site inspection for readily detected leaks by sight and sound whenever company personnel or other personnel under the direction of the company are on site. Anytime a leak is detected by sight or sound, an attempt at repair should be made. If the leak is associated with mandated worker safety concerns, it should be so noted in follow-up reports;

- Within 30 days of a well being placed into production and at least annually thereafter, all wellhead and production equipment, surface lines and metering devices at each well and/or well pad including and from the wellhead leading up to the onsite separator's outlet would be inspected for VOC, methane and other gaseous or liquid leaks. Leak detection would be conducted by visible and audible inspection and through the use of at least one of the following: 1) electronic instrument such as a forward looking infrared camera, 2) toxic vapor analyzer, 3) organic vapor analyzer, or 4) other instrument approved by the department;

- All components noted above that are possible sources of leaks would be included in the inspection and repair program. These components include but are not limited to: line heaters, separators, dehydrators, meters, instruments, pressure relief valves, vents, connectors, flanges, open-ended lines, pumps and valves from and including the wellhead up to the onsite separator's outlet;

- For each detected leak, if practical and safe an initial attempt at repair would be made at the time of the inspection, however, any leak that is not able to be repaired during the inspection may be repaired at any time up to 15 days from the date of detection provided it does not pose a threat to on-site personnel or public safety. All leaking components which cannot be repaired at detection would be identified for such repair by tagging. All repaired components would be re-inspected within 15 days from the date of the initial repair and/or re-repair to confirm, using one of the approved leak detection instruments, the adequacy of the repair and to check for leaks. The department may extend the period allowed for the repair(s) based on site-specific circumstances or it may require early well or well pad shutdown to make the repair(s) or other appropriate action based on the number and severity of tagged leaks awaiting repair; and

- Site inspection records would be maintained for a minimum period of 5 years. These records would include the date and location of the inspection, identification of each leaking component, the date of the initial attempt at repair, the date(s) and result(s) of any re-inspection and the date of the successful repair if different from initial attempt.

7.6.8 Mitigating GHG Emissions Impacts - Conclusion

Well operators can reduce their GHG emissions through active participation in the EPA's Natural Gas STAR Program, leak detection and repair, and through effective planning and implementation of necessary activities. The Department proposes to require, as a permit condition for high-volume hydraulic fracturing that the operator construct and operate the site in accordance with a greenhouse gas emissions impacts mitigation plan that may incorporate the above practices and considers, to the extent practicable, any applicable Department policy documents. However, the impacts mitigation plan would, at a minimum, include:

- a list of GHG-related BMPs planned for implementation at the permitted well site;

- a Leak Detection and Repair Program consistent with the SGEIS;

- required use and a description of EPA's Natural Gas STAR Best Management Practices for any equipment (e.g., low bleed gas-driven pneumatic valves and pumps) located from the wellhead to the onsite separator's outlet (Department's regulatory authority cutoff as described in Chapter 8);

- a description of planned use of reduced emissions completions, if any, including an estimate of the amount of methane that would be recovered instead of flared by the use of such; and

- a statement that upon request the operator would provide the Department with a copy of its report(s) for New York State as required under the EPA's GHG reporting rule discussed in Chapter 8. The operator would provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, records would be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.

Further, partners in EPA's Natural Gas STAR Program should include proof of their participation and starting date. The operator's greenhouse gas emissions impacts mitigation plan would be available to the Department upon request.

The Department proposes to require, via permit condition, the following additional requirements:

- Gas vented through the flare stack would be ignited whenever possible. The stack would be equipped with a self-ignition device; and
- A reduced emissions completion, with minimal flaring (if any), would be performed whenever a sales line is available during completion at any individual well or the multi-well pad.

The aforementioned requirements, if implemented, would mitigate GHG emissions to the maximum extent practicable.

7.7 Mitigating NORM Impacts

7.7.1 State and Federal Responses to Oil and Gas NORM[93]

Discovery of elevated concentrations of NORM levels in other areas outside of New York in the 1980s led to a series of state and private investigations of the issue. State responses to the potential of elevated oil and gas NORM range from no action (barring self-reported problems) to decisions for further study, to implementation of new formal regulations and guidance documents. NORM is not subject to direct federal regulation (except its transport) under either the AEA or LLRWPA, and exploration and production (E&P) wastes are specifically exempt from regulation under Subtitles D and C of RCRA (LA Office of Conservation, 2009); however, NORM is regulated indirectly at the federal level through potential environmental impacts to drinking water (SDWA) and cleanup of abandoned hazardous waste sites (CERCLA and NCP).

[93] Alpha, 2009, p. 2-44 et seq.

7.7.2 Regulation of NORM in New York State

In New York State, the handling of radioactive material and waste is regulated. Requirements for radioactive materials licensing, excluding medical and educational uses in New York City and entities under exclusive federal jurisdiction, are in the State Sanitary Code, Chapter 1, Part 16 (10 NYCRR 16) and Industrial Code Rule 38 (12 NYCRR 38). The NYSDOH is the licensing agency, and it enforces both Part 16 and Code Rule 38. Requirements for environmental discharges, waste shipment and disposal, or environmental cleanup are regulated by the Department under its 6 NYCRR Part 380 series of regulations. Additionally, the Department's solid waste disposal regulations, Part 360, precludes disposal of wastes regulated under Part 380 in a Part 360 solid waste landfill.

Disposal of flowback waster or brine through a POTW is addressed in section 7.1.8.1.

The overall licensing requirement for radioactive material, §16.100 of the State Sanitary code states, in part, that "no person shall transfer, receive, possess or use any radioactive material except pursuant to a specific or general license issued under this Part." Exemptions to the overall requirement are listed in Part 16, Appendix 16-A. In summary, any person is exempt from the requirements to the extent that such person transfers, receives, possesses or uses products or materials containing radioactive material in concentrations and quantities not in excess of those listed in the accompanying tables. Where multiple radionuclides are present, the sum of the ratios shall not exceed unity (one).

The discharge of licensed radioactive material and processed and concentrated NORM (such as waste filters, sludges, or backwash from the treatment of flowback water or production brine) into the environment is regulated by the Department. NORM contained in flowback water or production brine may be subject to applicable SPDES permit conditions.

Analytical results from initial sampling of production brine from vertical gas production wells in the Marcellus formation have been reviewed and suggest that the potential for NORM scale buildup in pipes and equipment may require licensing of a facility. The results also indicate that production brine may be subject to discharge limitations to ensure compliance with Part 380.

Existing data from drilling in the Marcellus Formation in other States, and from within New York for wells that were not hydraulically fractured, shows significant variability in NORM content. This variability appears to occur both between wells in different portions of the formation and at a given well over time. This makes it important that samples from wells in different locations within New York State are used to assess the extent of this variability. During the initial Marcellus development efforts, sampling and analysis would be undertaken in order to assess this variability. These data would be used to determine whether additional mitigation is necessary to adequately protect workers, the general public, and environment of the State of New York.

In order to determine which gas production facilities may be subject to the licensing and environmental discharge requirements, radiological surveys and measurements are necessary including radiation exposure rate measurements of areas of potential NORM contamination, accessible piping, tanks or other equipment that could contain NORM pipe scale buildup. Facilities that possess NORM wastes or piping, tanks or other equipment with elevated radiation levels may need a radioactive materials license. Further, any discharge of effluents into the environment would need to be tested for NORM concentrations in order to ensure compliance with regulatory requirements.

The Department proposes to require, via permit condition and/or regulation, that radiation surveys be conducted at specified time intervals for Marcellus wells developed by high-volume hydraulic fracturing completion methods on all accessible well piping, tanks, or other equipment that could contain NORM scale buildup. The surveys would be required to be conducted for as long as the facility remains in active use. Once taken out of use no increases in dose rate are to be expected. Therefore, surveys may stop until either the site again becomes active or equipment is planned to be removed from the site. If equipment is to be removed, radiation surveys would be performed to ensure appropriate disposal of the pipes and equipment. All surveys would be conducted in accordance with NYSDOH protocols. The NYSDOH's Radiation Survey Guidelines and a sample Radioactive Materials Handling License are presented in Appendix 27.

The Department finds that existing regulations, in conjunction with the proposed requirements for radiation surveys, would fully mitigate any potential significant impacts from NORM.

7.8 Socioeconomic Mitigation Measures[94]

High-volume hydraulic fracturing operations would have many positive socioeconomic results in the local areas where development is expected to occur. These operations would likely result in a substantial increase in economic activity in the affected areas, as well as a substantial increase in tax revenues to the state and localities. However, as described in previous sections, this increased economic activity would also have the potential to result in adverse impacts in regions with high drilling activity, particularly acute in the short term, including localized impacts on the housing market caused by the in-migration of construction and production workforces and an increase in demand for certain state and local government services, resulting in increased government expenditures.

As discussed in Section 6.8, potentially significant adverse impacts on local communities associated with an increase in population and increased demand for housing and community services are tied to the rate of development. Impacts that were potentially significant under the average development scenario were not as significant under the low development scenario. Similarly, impacts on population, housing, and community services are more significant when concentrated in smaller geographic areas than when incurred across broader geographic areas or statewide. The rate and concentration of development also affects the significance of impacts on visual resources, the ambient noise environment, and transportation networks.

The rate and concentration of development is related to many factors that cannot necessarily be controlled, such as the price of natural gas, input costs, the price of other energy sources, changes in technology, and the general economic conditions of state and nation, which will all affect the overall rate of development, as well as the uncertainty in the development potential of the Marcellus and Utica Shales.

Through its permitting process, the Department will monitor the pace and concentration of development throughout the state to mitigate adverse impacts at the local and regional levels. The Department will consult with local jurisdictions, as well as applicants, to reconcile the timing of development with the needs of the communities. Where appropriate the Department

[94] Section 7.8, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

would impose specific construction windows within well construction permits in order to ensure that drilling activity and its cumulative adverse socioeconomic effects are not unduly concentrated in a specific geographic area.

Another way to mitigate the potential adverse impacts associated with in-migration to the region would be to actively encourage the hiring of local labor. Because natural gas exploration, drilling, and production activities typically require specialized skills, a jobs training program or apprentice program should be developed through the SUNY system (e.g., community colleges and agricultural and technical colleges) to increase the number of local residents with the requisite job skills for the natural gas industry, thereby reducing the number of workers that would need to be hired from outside the region. Such a program would also have the benefit of reducing unemployment in these regions. A jobs training program would not eliminate the need for in-migration of skilled labor, but the program could partially offset the in-migration of workers and thus partially offset the potential housing impact from such in-migration.

7.9 Visual Mitigation Measures[95]

As noted, in most cases high-volume hydraulic fracturing operations would not result in significant adverse impacts on visual resources. The most significant visual impacts would result from construction of the well pad and well, and those impacts would be of short duration. Nevertheless, this section describes generic measures to address temporary adverse impacts of well site construction, development, production, and reclamation on visual resources. These measures could be undertaken in cases where well construction takes place near visually sensitive areas identified within the area underlain by the Marcellus and Utica Shales in New York State. Measures to mitigate impacts on visual resources would be generally similar, regardless of the type of visual resource or its location, and despite the need for compliance with rules, regulations, and permits promulgated by other federal, state, and/or local (town, county or regional) agencies.

The development of measures to reduce impacts on visual resources or visually sensitive areas would follow the procedures identified in NYSDEC DEP-00-2, “Assessing and Mitigating

[95] Section 7.9, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

Visual Impacts" (NYSDEC 2000). These measures can generally be divided into: design and siting measures that could be incorporated during the construction, development, and production phases; maintenance measures that could be incorporated into the development and production phases; and decommissioning measures that could be incorporated into the reclamation phase. Offsetting mitigation, as opposed to avoidance and direct mitigation measures, would typically be used only as a last resort for the resolution of significant impacts on visual resources or visually sensitive areas, as determined by Department staff. These measures are discussed in greater detail in the following subsections.

Generally, mitigation measures would be developed in consultation between Department staff and well operators and would be site-specific, or project-specific where multiple sites are a part of the project design. Depending on the location of the well pad and the resource potentially impacted, it may also be necessary to consult with additional state and federal regulatory agencies to develop measures to mitigate visual impacts on specific types of visual resources or visually sensitive areas, including but not limited to the New York State Historic Preservation Officer for NRHP-listed or -eligible historic properties; consultation with the National Park Service for National Historic Landmarks (NHLs) and National Natural Landmarks (NNLs); consultation with the U.S. Fish and Wildlife Service for National Wildlife Management Areas; consultation with the NYSDOT for state-designated Scenic Byways, etc.; and consultation with local (town, county, or regional) agencies for locally designated visual resources or visually sensitive areas that were identified on the EAF.

7.9.1 Design and Siting Measures

Design and siting measures, as described in NYSDEC DEP-00-2, would typically consist of screening, relocation, camouflage or disguise, maintaining low facility profiles, downsizing the scale of a project, using alternative technologies, using non-reflective materials, and controlling off-site migration of lighting (NYSDEC 2000). These various design and siting techniques are summarized below.

- **Screening**. Screening uses natural or man-made objects to conceal other objects from view; these objects may be constructed of any material that is opaque.

- **Relocation**. Relocation consists of moving facilities or equipment within a site to take advantage of the mitigating effects of topography and/or vegetation.

- **Camouflage or disguise**. Camouflage or disguise consists of using forms, colors, materials, and patterns to minimize or mitigate visual impacts.

- **Low profiles**. The use of low profiles consists of reducing the height of on-site objects to minimize their visibility from surrounding viewsheds.

- **Downsizing**. Downsizing consists of reducing the number, areas, or density of objects on a site to minimize their visibility from surrounding viewsheds.

- **Alternative technologies**. The use of alternative technologies consists of substituting one technology for another to reduce impacts.

- **Non-reflective materials**. The use of non-reflective, materials consists of using materials that do not shine or reflect light into surrounding viewsheds.

- **Lighting**. Lighting should be the minimum necessary for safe working conditions and for public safety, and should be sited to minimize off-site light migration, glare, and 'sky glow' light pollution.

Design and siting measures are the simplest and most effective methods for avoiding, minimizing, or mitigating direct and indirect impacts on visual resources or visually sensitive areas. For example, the state has determined that surface drilling would be prohibited on state-owned land, including reforestation areas and wildlife management areas, which would include many of the types of visual resources or visually sensitive areas discussed in Section 2.4. Implementing this siting measure would result in the exclusion from surface drilling of many resources and areas that may be designated or used, in part or in whole, for their scenic qualities, thereby decreasing the potential for direct visual impacts of surface drilling on such resources or areas. The implementation of design and siting measures would also minimize indirect impacts on visual resources or visually-sensitive areas that are outside of, but in close proximity to, areas where drilling is proposed.

Additional use of design and siting measures to avoid, reduce, or mitigate visual impacts would typically be implemented during the construction, development, and production phases of a well site. These measures could be used individually or in combination as determined appropriate and feasible by Department staff and well operators.

For example, the use of multi-well pads for horizontal drilling and hydraulic fracturing is a design and siting measure that incorporates both relocation and downsizing techniques by installing more than one well in one location. The benefit of the multi-well pad is that it decreases the overall number of pads in the surrounding landscapes, which would result in the decreased potential for impacts on visual resources or visually sensitive areas during the construction, development, production, and reclamation phases.

The use of horizontal drilling and high-volume hydraulic fracturing is a design and siting measure that incorporates the use of alternative technology to extract natural gas from the prospective Marcellus and Utica Shale region. The benefit of horizontal drilling and high-volume hydraulic fracturing is that it provides flexibility in pad location, such that well pads can be sited to avoid or minimize the potential for temporary, short-term, and long-term impacts on visual resources or visually sensitive areas during the construction, development, production, and reclamation phases (NTC 2011). Such considerations should be reflected in Department consideration of well pad applications.

The potential benefit of using camouflage or disguise as a design measure to minimize impacts on visual resources or visually sensitive areas is shown in Photo 7.1 below. This photo shows fracturing activities on a well site, a phase when well sites are almost entirely filled with on-site equipment, which represents new landscape features and results in an area that appears visually prominent in views from nearby vantage points. Although the fracturing phase of development is considered temporary and periodic (as described in Section 6.11), it would be possible to minimize visual impacts during fracturing activities that might occur in the spring, summer, or fall by requiring on-site water storage tanks (the red tanks in Photo 7.1) to be a green color to mimic surrounding conditions. This would reduce the prominence of the tanks in the surrounding landscape during seasons when visual resources or visually sensitive areas are typically visible to the greatest numbers of the viewing public.

Photo 7.1 - View of a well site during the fracturing phase of development, with maximum presence of on-site equipment. (New August 2011)

The 2010 visual impact assessment (Upadhyay and Bu 2010) evaluated the effectiveness of implementing certain design and siting techniques as measures to mitigate visual impacts. Using aerial photograph interpretation, the authors suggested that reducing the size of the well pad (downsizing) after drilling (the development phase) was complete could result in reduced site-specific visual impacts from surrounding vantage points and that reducing the density of multiple well pads in an area could result in reduced visual impacts within a larger area or region (e.g., within a county). Their study further suggested that the following design and siting measures would avoid or minimize visual impacts from surrounding vantage points: relocating well sites to avoid ridgelines or other areas where aboveground equipment and facilities breaks the skyline; and minimizing off-site light migration by using night lighting only when necessary and using the minimum amount of nighttime lighting necessary, directing lighting downward instead of horizontally, and using light fixtures that control light to minimize glare, light trespass (off-site light migration), and light pollution (sky glow) (Upadhyay and Bu 2010).

A tourism study (Rumbach 2011) prepared for the Southern Tier Central (STC) Regional Planning and Development Board suggests that visual impacts from horizontal drilling and hydraulic fracturing could be most effectively addressed during the siting and design phases by ensuring that well pads are designed and located in ways that minimize potential impacts on visual resources or visually sensitive areas to the extent practicable. The study also encourages the inclusion of visual impact mitigation conditions, developed in accordance with NYSDEC DEP-00-2, in permits when visual resources may be impacted. The study also recommends the development of a best practices manual for Department staff and the industry, which would provide information on what is expected by the Department in terms of well siting and visual mitigation, and the identification of instances where visual mitigation may be necessary. Additional recommendations included encouraging local agencies (towns, counties, and regions) to identify areas of high visual sensitivity, which may require additional visual mitigation, and to develop a feedback mechanism in the project review process to confirm the success of measures to avoid, minimize, or mitigate visual impacts, based on the analysis of results for prior projects (Rumbach 2011).

7.9.2 Maintenance Activities

The maintenance activities described in NYSDEC DEP-00-2 should be implemented to prevent project facilities from becoming "eyesores." Such measures would typically consist of appropriate mowing or other measures to control undesirable vegetation growth; erosion control measures to prevent migration of dust and/or water runoff from a site; measures to control the off-site migration of refuse; and measures to maintain facilities in good repair and as organized and clean as possible according to the type of project (NYSDEC 2000).

Maintenance activities to avoid, reduce, or mitigate visual impacts would typically be implemented during the development and production phases for well sites. Facilities should be maintained in good repair and as organized and clean as possible.

Upadhyay and Bu's visual impact assessment evaluated the effectiveness of site restoration to minimize visual impacts on surrounding landscapes. Their definition of site restoration as a mitigation measure, defined as restoring drilling pads to their original condition after drilling and hydraulic fracturing activities (i.e., the development phase) are completed, is similar in concept to the NYSDEC DEP-00-2 definition of maintenance activities as a mitigation measure. Their conclusion was that site restoration following drilling and hydraulic fracturing activities was an effective way to reduce adverse visual impacts of producing well sites within the existing landscape. With appropriate site restoration, well sites in the production phase, when activity is minimal and there are only a few relatively unobtrusive aboveground structures on site, are not prominent features within the surrounding landscape (Upadhyay and Bu 2010).

7.9.3 Decommissioning

The decommissioning activities described in NYSDEC DEP-00-2 should be implemented when the useful life of the project facilities is over; these activities would typically occur during the reclamation phase for well sites.[96] Such activities would typically consist of, at a minimum, the removal of aboveground structures at well sites. Additional decommissioning activities that may also be required include: the total removal of all facility components at a well site (aboveground and underground) and restoration of a well site to an acceptable condition, usually with attendant vegetation and possibly including recontouring to reestablish the original topographic contours; the partial removal of facility components, such as the removal or other elimination of structures or features that produce visual impacts (such as the restoration of water impoundment sites to original conditions); and the implementation of actions to maintain an abandoned facility and site in acceptable condition to prevent the well site from developing into an eyesore, or prevent site and structural deterioration (NYSDEC 2000).

The tourism study prepared for the STC (Rumbach 2011) discusses additional measures that could be implemented during the reclamation phase to mitigate visual impacts. These measures, which would be applied to all well pads, include the application of specific procedures identified in the 1992 GEIS for topsoil conservation and redistribution in agricultural districts. These procedures include stripping off and stockpiling topsoil during construction; protecting stockpiled topsoil from erosion and contamination; cutting well casings to a safe buffer depth of 4 feet below the ground surface; preparing areas before topsoil redistribution if compaction has

[96] Although substantial equipment and activity would be present at well sites during the construction and development phases, such equipment and activities are temporary. Once construction and well development is completed, some activities would cease and some equipment would be removed, and these are not considered to be decommissioning activities.

occurred on-site; and redistributing the topsoil over the disturbed area of the former well pads during reclamation (Rumbach 2011).

7.9.4 Offsetting Mitigation

The offsetting mitigation described in NYSDEC DEP-00-2 should be implemented when the impacts of well sites on visual resources or visually sensitive areas are significant and when such impacts cannot be avoided by locating the well pad in an alternate location. Per guidance in NYSDEC DEP-00-2, offsetting mitigation would consist of the correction of an existing aesthetic problem identified within the viewshed of a proposed well project. Thus, a decline in the landscape quality that would result from development of a proposed well site could, at least partially, be 'offset' by the correction. An example of offsetting mitigation might be the removal of an existing abandoned structure that is in disrepair (i.e., an 'eyesore') to offset impacts from the development of a well site within visual proximity to the same sensitive visual resource (NYSDEC 2000). Offsetting mitigation should be employed only when significant improvements in visually sensitive locations can be expected at a reasonable cost (NYSDEC 2000).

7.10 Noise Mitigation Measures[97]

Noise is best mitigated by increasing distance between the source and the receiver; the greater the distance the lower the noise impact. The second level of noise mitigation is direction. Directing noise-generating equipment away from receptors greatly reduces associated impacts. Timing also plays a key role in mitigating noise impacts. Scheduling the more significant noise-generating operations during daylight hours provides for tolerance that may not be achievable during the evening hours.

7.10.1 Pad Siting Equipment, Layout and Operation

Many of the potential negative impacts of gas development depend on the location chosen for the well pad and the techniques used in constructing the access road and well site. Before a drilling permit can be issued, Department staff must ensure that the proposed location of the well and access road complies with the Department's spacing regulations and siting restrictions. To assist

[97] Section 7.10, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

in this process, Department staff will rely on Policy Guidance Document DEP-00-1, "Assessing and Mitigating Noise Impacts."

The benefits of a multi-well pad are the reduced number of sites generating noise and, with the horizontal drilling technology, the flexibility to site the pad in the best location to mitigate the impacts. As described above and in more detail in Subsection 5.1.3.2, current regulations allow for a single well pad per 40-acre spacing unit, one multi-well pad per 640-acre spacing unit, or various other combinations. This provides the potential for one multi-well pad to recover the resource in the same area that could contain up to 16 single well pads.

With proper pad location and design, the adverse noise impacts could be significantly reduced. A multi-well pad provides a platform to extract gas over a wider area than the area exploited by a single vertical well. This provides an opportunity to locate the multi-well pad away from a noise receptor and in a location where there is intervening topography and vegetation, which can reduce the noise level at the receptor location to a level below that which might result from several single-well pads in close proximity to the receptor location.

Multi-well pads also have the potential to greatly reduce the amount of trucking and associated noise in an area. Rigs and equipment may only need to be delivered and removed one time for the drilling and stimulation of all of the wells on the pad. Reducing the number of truck trips required for fracturing water is also possible by reusing water for multiple fracturing jobs. In certain instances, it also may be economically viable to transport water via pipeline to a multi-well pad.

7.10.2 Access Road and Traffic Noise

As noted, high-volume hydraulic fracturing results in a greater number of heavy truck trips to the well pad compared to conventional drilling. Given the extensive trucking and associated noise involved with water transportation for high-volume hydraulic fracturing, attention should be given to the location of access road(s). Where appropriate, roads should be located as far as practicable from occupied structures and places of assembly. This would serve to protect noise receptors from noise impacts associated with trucking and road construction that could conflict with their property use.

Traffic noise mitigation measures may include modification of speed limits and restricting or prohibiting truck traffic on certain roads. Restricting truck use on a given roadway would reduce noise levels at nearby receptors, since trucks are louder than cars. However, displacing truck traffic from one roadway to another would shift noise impacts from one area to another. While reducing speeds may reduce noise levels, a reduction of at least 10 mph is needed to achieve a noticeable difference in noise level.

7.10.3 Well Drilling and Hydraulic Fracturing

As discussed in the 1992 GEIS (NYSDEC 1992), moderate to significant noise impacts may be experienced within 1,000 feet of a well site during the drilling phase. With the extended duration of drilling and other activities involved with multi-well pads, the Department will review the location of multi-well pads closer than 1,000 feet to occupied structures and places of assembly and determine what mitigation is necessary to minimize impacts.

Once the location and layout of a drilling site have been established and prior to the execution of the drilling project, noise modeling should be required using commercially available noise modeling software for any site located within 1,000 feet of a noise receptor. The software should be capable of simulating the three-dimensional outdoor propagation of sound from each noise source and account for sound wave divergence, atmospheric and ground sound absorption, and sound attenuation due to interceding barriers and topography. The effect of topography on noise propagation would be an important factor in the areas where drilling to access the Marcellus and Utica Shales would likely occur. The results of the modeling should be used by the applicant to evaluate noise levels that would be experienced at the nearest noise receptors and to develop mitigation measures for use in controlling noise levels generated during drilling and hydraulic fracturing of the well(s).

Examples of noise mitigation techniques that can be implemented as site-specific permit conditions include the following, as practicable:

- requiring the measurement of ambient noise levels prior to beginning operations;
- specifying daytime and nighttime noise level limits as a permit condition and periodic monitoring thereof;

- placing tanks, trailers, topsoil stockpiles, or hay bales between the noise sources and receptors;
- using noise-reduction equipment such as hospital-grade mufflers, exhaust manifolds, or other high-grade baffling;
- limiting drill pipe cleaning ("hammering") to certain hours;
- running of casing during certain hours to minimize noise from elevator operation;
- placing air relief lines and installing baffles or mufflers on lines;
- limiting cementing operations to certain hours (i.e., perform noisier activities, when practicable, after 7 A.M. and before 7 P.M.);
- using higher or larger-diameter stacks for flare testing operations;
- placing redundant permanent ignition devices at the terminus of the flow line to minimize noise events of flare re-ignition;
- providing advance notification of the drilling schedule to nearby receptors;
- placing conditions on air rotary drilling discharge pipe noise, including:
    - orienting high-pressure discharge pipes away from noise receptors;
    - having the air connection blowdown manifolded into the flow line. This would provide the air with a larger-diameter aperture at the discharge point;
    - having a 2-inch connection air blowdown line connected to a larger-diameter line near the discharge point or manifolded into multiple 2-inch discharges;
    - shrouding the discharge point by sliding open-ended pieces of larger-diameter pipe over them; or
    - rerouting piping so that unusually large compressed air releases (such as connection blowdown on air drilling) would be routed into the larger-diameter pit flow line to muffle the noise of any release.
- using rubber hammer covers on the sledges when clearing drill pipe;
- laying down pipe during daylight hours;
- scheduling drilling operations to avoid simultaneous effects of multiple rigs on common receptors;

- limiting hydraulic fracturing operations to a single well at a time;
- employing electric pumps; and
- installing temporary sound barriers (see Photo 7.2, Photo 7.3, and Photo 7.4) of appropriate heights, based on noise modeling, around the edge of the drilling location between a noise generating source and any sensitive surroundings. Sound control barriers should be tested by a third-party accredited laboratory to rate Sound Transmission Coefficient (STC) values for comparison to the lower-frequency drilling noise signature.

Photo 7.2 - Sound Barrier. Source: Ground Water Protection Council, Oklahoma City, OK and ALL Consulting, Tulsa OK, 2009 (New August 2011)

Source: Penn State Cooperative Extension

Photo 7.3 - Sound Barrier Installation (New August 2011)

Photo 7.4 - Sound Barrier Installation (New August 2011)

Many of these mitigation techniques have been successfully applied at wells drilled in New York. In addition, based upon NYSDEC's recommendations, these mitigation measures have been incorporated into Environmental Assessments prepared by the Federal Energy Regulatory Commission for proposed natural gas storage projects in New York, supporting the agency's findings that the proposed projects would have no significant environmental impact.

7.10.4 Conclusion

As discussed in the 1992 GEIS (NYSDEC 1992), temporary, short-term noise impacts may vary, based on the presence of topographic barriers (e.g., hills) or vegetative barriers (e.g., hills, trees, tall grass, shrubs). Drilling and hydraulic fracturing operations are the noisiest phase of development and usually continue 24 hours a day. Noise sources during the drilling phase include various drilling rig operations, pipe handling, compressors, and the operation of trucks, backhoes, tractors, and cement mixers. During hydraulic fracturing, the primary source of noise is the multiple frac fluid pumps operating simultaneously. In most instances, the closest receptor is the residence of the owner of the property where the well is located, and the owner will have agreed to the disturbance by entering into a voluntary lease agreement with the well operator. However, this may not always be the case, due to compulsory integration and other circumstances. Noise impacts can be mitigated, when necessary, at nearby receptors (regardless of lease status) by a combination of setbacks, site layout to take advantage of existing topography, implementation of noise barriers, and special permit conditions.

The 1992 GEIS (NYSDEC 1992) indicated that there were unavoidable adverse noise impacts for those living in proximity to a drill site. These were determined to be short term and could be mitigated with siting restrictions and setback requirements. Given that the types of noise impacts associated with horizontal drilling with high-volume hydraulic fracturing have been found to be similar to those for vertical drilling, these findings are also applicable to horizontal drilling and high-volume hydraulic fracturing. The extended time period for horizontal drilling with high-volume hydraulic fracturing, while still temporary, makes the control of noise impacts essential. Since noise control is most effectively addressed during the siting and design phase, it is important that the pad be properly located and planned, and horizontal drilling provides the flexibility to accommodate this need. The Department's guidance document DEP-00-01, "Assessing and Mitigating Noise Impacts," should be utilized along with a site plan and noise modeling (when the well pad is to be located within 1,000 feet of occupied structures or places of assembly) for this purpose. In addition, the applicant is encouraged to review any applicable local land use policy documents with the understanding that NYSDEC retains authority to regulate gas development (NTC 2011).

Supplementary permit conditions for high-volume hydraulic fracturing would include the following requirements to mitigate potential noise impacts:

- unless otherwise required by private lease agreement, the access road must be located as far as practicable from occupied structures, places of assembly, and occupied but unleased property; and
- the well operator must operate the site in accordance with a noise impacts mitigation plan consistent with the SGEIS.

The operator's noise impacts mitigation plan shall be provided to the Department along with the permit application. Additional site-specific noise mitigation measures will be added to individual permits if a well pad is located within 1,000 feet of occupied structures or places of assembly.

7.11 Transportation Mitigation Measures[98]

The transportation of water, hydraulic fracturing materials, and liquid wastes appears to account for well over 90% of all heavy truck traffic from a gas well over its productive life. Mitigating measures can help prevent, reduce or compensate for the potentially significant adverse impacts resulting from the increased transportation and road use related to vehicular traffic necessary for horizontal drilling and high-volume hydraulic fracturing. These are summarized by potential impact category as described in Section 6.11.

7.11.1 Mitigating Damage to Local Road Systems

As discussed in Section 6.11, the majority of impacts on roads would occur on local roads near the wells. The following measures would mitigate impacts of increased transportation, particularly by heavy trucks, on local road systems.

[98] Section 7.11, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

7.11.1.1 Development of Transportation Plans, Baseline Surveys, and Traffic Studies

The Department would require, as part of any permit application, that the applicant submit a transportation plan. The transportation plan would identify the number of anticipated truck trips to be generated by the proposed activity; the times of day when trucks are proposed to be operating; the proposed routes for such truck trips; the locations of, and access to and from, appropriate parking/staging areas; and the ability of the roadways located on such routes to accommodate such truck traffic. The transportation plan would also identify whether the operator has entered into a road use agreement or agreements with local governments and the condition of roads and bridges that are expected to be used by trucks directly and indirectly associated with the drilling operation. No permit should be issued until the Department and the NYSDOT are satisfied that the Transportation Plan is adequate to ensure that the traffic associated with the activity can be conducted safely and would reduce the impacts from truck traffic on local road systems to the maximum extent feasible.

It is important that the Transportation Plan evaluate pre-impact conditions so that any potential damages to roads and infrastructure can be fairly assessed. Establishing an accurate assessment of current conditions by conducting a baseline survey can be beneficial to both the local municipality and the operator; such baseline surveys should include information for local, state and interstate roads. State and interstate highways are surveyed annually and state secondary roads are surveyed every two years (NYSDOT 2010). However, local municipalities may not have the funds, equipment, or staff to survey local roads on a regular basis. Therefore, it would be the responsibility of the operator to conduct a baseline survey of local roads in accordance with methods described in the NYS traffic survey methods manual (NYSDOT 2010).

The results of a baseline survey of local road conditions should be combined with an assessment of the existing heavy truck traffic on the local roads and the relative amount of project-related traffic to develop a road condition study. This road condition study would be used to assess the proportion of the cost of road repairs that would be the responsibility of the operator. For example, if the road condition study concludes that the well operator would double the existing heavy truck traffic, and the road condition study indicates that a deterioration of pavement condition during the heavy traffic period of the project would occur, then the operator would be required to have an agreement in place to pay for the work required to repair or prevent the road deterioration.

7.11.1.2 Municipal Control over Local Road Systems

Under NYS highway vehicle traffic laws, local municipalities retain control over their roads, and as such, can implement measures to prevent or minimize transportation impacts. For example, NYS Vehicle and Traffic Law § 1640(a)(5) provides that, "The legislative body of any city or village, with respect to highways … in such city or village … may by local law, ordinance, order, rule or regulation … exclude trucks, commercial vehicles, tractors, tractor-trailer combinations, [and] tractor-semitrailer combinations from highways specified by such legislative body." Part 10 of this same section allows legislative bodies of a city or village to "establish a system of truck routes upon which all trucks, tractors and tractor-trailer combinations, having a gross weight in excess of ten thousand pounds are permitted to travel and operate and excluding such vehicles and combinations from all highways except those which constitute such truck route system." Part 20 of this same section allows for the establishment of weight, height, length, and width criteria, for which vehicles in excess of such standards may be excluded from highways or the setting of limits on hours of operation of such vehicles on particular city or village highways or segments of such highways. Essentially, NYS Vehicle and Traffic Law §1640(a) (5), (10), and (20) allow local governments to establish regulations pertaining to the use of city or town highways by trucks, tractor trailers, etc., and to exclude such vehicles from use of city or town highways as may be delineated by the local legislative body.

In addition to city and village ordinances or rules that may govern the use of highways within a city or village, NYS Vehicle and Traffic Law § 1650(4)(a) provides that "the county superintendent of highways of a county with respect to county roads in such county, may by order, rule or regulation: … exclude trucks, commercial vehicles, tractors, etc. in excess of designated weight, length, height and width from county highways, or set limits of hours of operation for such vehicles." This is essentially the same legislative authority given to cities and villages in Vehicle and Traffic Law §1640, except this pertains to counties. The same is true of Vehicle and Traffic Law § 1660(a) (10), (11), (17), and (28), which allow for the same exclusion of trucks, tractors, tractor-trailers, etc., as provided in the previous Articles, except that this section pertains to the authority of a town's legislative body. In addition, Town Law § 130 (7) allows for a town board, after a public hearing, to enact, amend, or repeal ordinances, rules, and regulations pertaining to the use of streets, highways, sidewalks, and public places by pedestrians, motor and other vehicles, and restrict parking of all vehicles therein.

As noted above, municipalities would be notified of applications that indicate that high-volume hydraulic fracturing is planned. In addition, municipalities should monitor the Department's Web site for additional information regarding gas development in their areas. In light of their substantial authority over access to local roads, local governments (county, town, and village) would likely be proactive in exercising their authority under NYS highway vehicle traffic laws. This would include requiring a local road use agreement (discussed below), taking into account the required road condition study, which would provide the basis for potentially assessing fees for maintenance and improvements to local roads.

7.11.1.3 Road Use Agreements

As stated above in Section 7.11.1.1, local governments have the authority to enter into road use agreements with well operators, which identify where an operator may or may not drive trucks, weight limits, times of day, etc. Therefore, the owner or operator should attempt to obtain a road use agreement with the appropriate local municipality; if such an agreement cannot be reached, the reason(s) for not obtaining one must be documented in the Transportation Plan. The owner or operator would also have to demonstrate that, despite the absence of such agreement, the traffic associated with the activity can be conducted safely and that the owner or operator would reduce the impacts from truck traffic on local road systems to the maximum extent feasible.

The road use agreement would be the primary mechanism by which local governments can hold well operators accountable for damages and repairs to roads, bridges, and drainage structures that may be impacted by their excess use. When utilized appropriately, this mechanism has proven effective with wind developers in New York State.

Measures that should be part of a road use agreement or trucking plan, as appropriate, include:

- Route selection to maximize efficient driving and public safety, pursuant to city or town laws or ordinances as may have been enacted under Vehicle and Traffic Law §1640(a)(10);

- Avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods, as established by Vehicle and Traffic Law §1640(a)(20);
- Coordination with local emergency management agencies and highway departments;
- Upgrades and improvements to roads that will be traveled frequently for water transport to and from many different well sites, as may be reimbursable pursuant to ECL §23-0303(3);
- Advance public notice of any necessary detours or road/lane closures;
- Adequate off-road parking and delivery areas at the site to avoid lane/road blockage; and
- Use of rail or temporary pipelines where feasible to move water to and from well sites.

Supplementary permit conditions for high-volume hydraulic fracturing would re-emphasize that issuance of a well permit does not provide relief from any local requirements authorized by or enacted pursuant to the Vehicle and Traffic Law. Such permit conditions would also require the following:

1. Prior to site disturbance, the operator shall submit to the Department and provide a copy to the NYSDOT of any road use agreement between the operator and local municipality.
2. The operator shall file a transportation plan, which shall be incorporated by reference into the permit; the plan will be developed by a NYS-licensed Professional Engineer in consultation with the Department and will verify the existing condition and adequacy of roads, culverts, and bridges to be used locally.

When there is no agreement, the applicant should nevertheless be guided by Environmental Conservation Law (ECL) § 23-0303(2), which provides that "this article shall supersede all local laws or ordinances relating to the regulation of the oil, gas and solution mining industries; but shall not supersede local government jurisdiction over local roads or the rights of local governments under the real property tax law." This gives local municipalities the authority to designate and enforce vehicle and traffic laws pertaining to the use of local roads by motor vehicles, including trucks engaged in activities connected to gas drilling.

7.11.1.4 Reimbursement for Costs Associated with Local Road Work

Under Highway Law § 136 (2), "a county superintendent shall establish regulations governing the issuance of highway work permits, including the fees to be charged therefor, a system of deposits of money or bonds guaranteeing the performance of the work and requirements of insurance to protect the interests of the county during performance of the work pursuant to a highway work permit." It is through this legislation that a county is able to financially mitigate impacts on roads and highways caused by roadwork associated with well development, but this law would not provide for payments for damages to roads from excess use.

7.11.2 Mitigating Incremental Damage to the State System of Roads

Truck traffic on the interstate highway system and other regional roads would also suffer wear and tear due to the added traffic associated with horizontal drilling and high-volume hydraulic fracturing. Given the potentially dramatic increase in the number of large trucks and their distribution in the high-volume hydraulic fracturing region, a significant expansion in truck inspection requirements would be expected. This would require close coordination with other organizations, including local municipalities and the State Police. There is likely to be a substantial increase in oversize/overweight permitting requests, which may require additional permit staff at NYSDOT to handle these requests.

In addition, the installation of associated infrastructure, such as gas and water pipeline expansions and extensions, would require highway work permits, resulting in additional management, oversight, and inspection services by NYSDOT staff. Local municipalities would also likely see a sharp increase in their transportation-related staffing needs and budgets. These additional needs would include staff to carry out or oversee road condition surveys, traffic counts (or studies), local road and detour postings, execution of Road Use or Excess Maintenance agreements, and other activities. Personnel and resources would be necessary to monitor road conditions, manage and enforce agreements, and provide regulatory and emergency services.

State permit regulations could be developed that assess mitigation fees as a permit condition to defray some of these new costs. Other state revenue sources and mechanisms for collecting fees to address damages and wear to the state system of roads would include contributions to the Highway and Bridge Conservation Fund, the collection of heavy vehicle registration fees, tolls and other highway use taxes, petroleum business taxes, and motor fuel taxes.

However, the revenue that is currently collected to compensate the state for damages to the state system of roads is deemed by NYSDOT to be insufficient for addressing required roadway maintenance. Thus, the added burden of the potential adverse impacts on the state system of roads associated with the proposed development of natural gas reserves using high-volume hydraulic fracturing may pose an additional financial burden on the state, which would be considered an adverse impact that may not be fully mitigated.

7.11.3 Mitigating Operational and Safety Impacts on Road Systems

Where appropriate, site-specific mitigation of safety impacts would be applied to each applicant's permit. These would include, but are not limited to, the following:

- Limiting truck weight, axle loading, and weight during seasons when roads are most sensitive to damage from trucking (e.g., during periods of frost heaving and high runoff);
- Requiring the operator to pay for the addition of traffic control devices or trained traffic control agents at peak times at identified problem intersections or road segments;
- Providing industry-specific training to first responders to prepare for potential accidents;
- Road use agreements limiting heavy truck traffic to off-hour periods, to the extent feasible, to minimize congestion;
- Providing a safety and operational review of the proposed routes, which may include commitments to providing changes to geometry, signage, and signaling to mitigate safety risks or operational delays; and
- Avoiding hours and routes used by school buses.

Due to the generic nature of this analysis and the unknown road segments where these heavy- and light-duty trucks would travel, it is not possible at this time to identify specific operational and safety impacts, nor is it possible to identify operational or safety mitigation strategies for specific locations. However, some combination of the identified measures can be used to mitigate impacts to the extent feasible.

As noted in Section 7.8 (Socioeconomic Mitigation Measures), through its permitting process, the Department will monitor the pace and concentration of development throughout the state to mitigate adverse impacts at the local and regional levels. The Department will consult with local jurisdictions, as well as applicants, to reconcile the timing of development with the needs of the communities. Where appropriate the Department would impose specific construction windows within well construction permits in order to ensure that drilling activity and its cumulative adverse socioeconomic effects are not unduly concentrated in a specific geographic area. Those measures, designed to mitigate socioeconomic impacts and impacts on community character, can also be employed to minimize operational and safety impacts where such impacts are identified.

7.11.4 Other Transportation Mitigation Measures

High-volume hydraulic fracturing is a relatively new and evolving technology, and the industry is exploring a variety of alternatives that could substantially reduce the need for and impacts of heavy trucks. Potential future alternatives include innovative methods of hydraulic fracturing such as the use of natural gas gels, which might entirely eliminate the need for trucking water to well sites; and innovative water supply systems such as the construction of water wells serving multiple well pads via a piping system, which would reduce the need for trucking water to well sites. On-site treatment and disposition of wastes is another potential alternative that could reduce the need for trucking. For example, Chesapeake Energy has eliminated the trucking of wastes from well sites through on-site treatment and disposition in the Marcellus Shale area in Pennsylvania. If this practice were extended to other gas development companies operating in other areas with gas-producing shales, such as the Marcellus and Utica Shales in New York, it would result in similar substantial reductions in the need for trucking.

7.11.5 Mitigating Impacts from the Transportation of Hazardous Materials

Preliminary data has been provided to the Department outlining the typical components of the fracturing fluids to be used in the state. The operator will provide specific information on the types and quantities of hazardous materials expected to be transported through the jurisdictions that they will be operating in and brought on site as part of the permitting process.

Specific information on the transportation of these materials is presented in Section 5.5. In summary, all fracturing fluids and additives are transported in “DOT-approved” trucks or containers. The federal Hazardous Material Transportation Act (HMTA) and Hazardous Materials Transportation Uniform Safety Act (HMTUSA) are the basis for federal hazardous materials transportation law and give regulatory authority to the Secretary of the USDOT to enforce the regulations. These extensive regulations address the potential concerns involved in transporting hazardous fracturing additives, including loading, unloading, shipping, and packaging. These regulations are enforced by the USDOT agencies and, when followed and enforced, effectively mitigate risks.

The NYSDOT requires all registrants of commercial motor vehicles to obtain a USDOT number and has adopted many USDOT regulations that apply to interstate highway transportation. There are minor exceptions to these federal regulations; however, the exemptions do not directly relate to the objectives of this review. New York State regulations include motor vehicle carriers that operate solely on an intrastate basis. These carriers must comply with 17 NYCRR Part 820 (as described in Section 5.5.2) in addition to the applicable requirements and regulations of the Vehicle and Traffic Law and the NYS Department of Motor Vehicles. This includes regulations requiring carriers to obtain authorization to transport hazardous materials from the USDOT or NYSDOT Commissioner.

Municipalities may require trucks transporting hazardous materials to travel on designated routes, in accordance with a road use agreement; however, this would not eliminate entirely the potential for an accidental release. Depending on its size and location, a spill could have a significant adverse impact on the local community. First responders and emergency personnel would need to be aware of hazardous materials being transported in their jurisdiction and also be properly trained in case of an emergency involving these materials. Permit conditions may require the operator to provide first responder emergency response training specific to the hazardous materials to be used in the drilling process if a review of existing resources indicates such a need, and transportation plans may provide that sensitive locations be avoided for trucks carrying hazardous materials.

7.11.6 Mitigating Impacts on Rail and Air Travel

The potential impacts on the rail industry would be positive. Growth in haulage, and consequently in revenues and employment, would likely occur. However, as evidenced in Pennsylvania, infrastructure would need to be improved (e.g., tracks extended, rail yards expanded, new sidings/offloading facilities provided at appropriate locations, etc.). The potential adverse impacts of increased traffic on the existing rail facilities could be mitigated by the construction of new facilities. The majority of financing for improvements is provided by the rail companies or through partnerships and investment partnerships with major users. At the same time, there can be a significant demand for public investment as well. The variety of financing and investment instruments can be drawn from Pennsylvania's experience, for example SEDA-COG Joint Railway Authority, which financed roughly $16 million of projects in six counties through a combination of USDOT grants ($10 million), a $3.8 million PennDOT grant, and a $2.2 million public-private partnership.

7.12 Community Character Mitigation Measures[99]

Local and regional planning documents are important in defining a community's character and are the principal way of managing change within a community. These plans are used to guide development and provide direction for land development regulations (e.g., zoning, noise control, and subdivision ordinances) and designation of special districts for economic development, historic preservation, and other reasons.

As discussed in Section 3, the Department would require the applicant to prepare an EAF Addendum for gathering and compiling the information needed to evaluate high-volume hydraulic fracturing projects (≥300,000 gallons) in the context of this SGEIS and its Findings Statement, and to identify the required site-specific mitigation measures.

The EAF Addendum would be required as follows:

- With the application to drill the first well on a pad constructed for high-volume hydraulic fracturing, regardless of whether the well is vertical or horizontal;
- With the applications to drill subsequent wells for high-volume hydraulic fracturing on the pad if any of the information changes; and
- Prior to high-volume re-fracturing of an existing well.

The EAF Addendum would require the applicant to identify whether the location of the well pad, or any other activity under the jurisdiction of the Department, conflicts with local land use laws, regulations, plans, or policies. The applicant would also be required to identify whether the well

[99] Section 7.12, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s).

Where the project sponsor indicates that the location of the well pad, or any other activity under the jurisdiction of the Department, is either consistent with local land use laws, regulations, plans, or policies, or is not covered by such local land use laws, regulations, plans, or policies, no further review of local land use laws and policies would be required.

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

In addition, a supplemental site-specific review is required when an applicant proposes to construct a well pad on a farm within an Agricultural District when the proposed disturbance is larger than 2.5 acres. In such cases, the Department would consult with the DAM to develop additional permit conditions, best management practice requirements, and reclamation guidelines to be followed.

Examples of the proposed Agricultural District requirements include but are not limited to the following:

- decompaction and deep ripping of disturbed areas prior to topsoil replacement;
- removal of construction debris from the site;
- no mixing of cuttings with topsoil;
- removal of spent drilling muds from active agricultural fields;
- location of well pads/access roads along field edges and in nonagricultural areas (where practicable);
- removal of excess subsoil and rock from the site; and

- fencing of the site when drilling is located in active pasture areas to prevent livestock access.

Implementation of these measures would lead to successful reestablishment of agricultural lands when well pads are no longer productive.

The socioeconomic, visual, noise, and transportation impacts discussed in Sections 6.8, 6.9, 6.10, and 6.11, respectively, also impact community character. To the extent that these impacts are mitigated as discussed in Sections 7.8 (Socioeconomic), 7.9 (Visual), 7.10 (Noise), and 7.11 (Transportation), impacts on community character would also be mitigated.

7.13 Emergency Response Plan

There is always a risk that despite all precautions, non-routine incidents may occur during oil and gas exploration and development activities. An Emergency Response Plan (ERP) describes how the operator of the site will respond in emergency situations which may occur at the site. The procedures outlined in the ERP are intended to provide for the protection of lives, property, and natural resources through appropriate advance planning and the use of company and community assets. The Department proposes to require supplementary permit conditions for high-volume hydraulic fracturing that would include a requirement that the operator provide the Department with an ERP consistent with the SGEIS at least 3 days prior to well spud. The ERP would also indicate that the operator or operator's designated representative will be on site during drilling and/or completion operations including hydraulic fracturing, and such person or personnel would have a current well control certification from an accredited training program that is acceptable to the Department.

The ERP, at a minimum, would also include the following elements:

- Identity of a knowledgeable and qualified individual with the authority to respond to emergency situations and implement the ERP;
- Site name, type, location (include copy of 7 ½ minute USGS map), and operator information;
- Emergency notification and reporting (including a list of emergency contact numbers for the area in which the well site is located; and appropriate Regional Minerals' Office), equipment, key personnel, first responders, hospitals, and evacuation plan;

- Identification and evaluation of potential release, fire and explosion hazards;
- Description of release, fire, and explosion prevention procedures and equipment;
- Implementation plans for shut down, containment and disposal;
- Site training, exercises, drills, and meeting logs; and
- Security measures, including signage, lighting, fencing and supervision.

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New York State

DEC

Chapter 8

Permit Process and Regulatory Coordination

Revised Draft
Supplemental Generic Environmental Impact Statement

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Chapter 8 – Permit Process and Regulatory Coordination

FIGURES

TABLES

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Chapter 8 PERMIT PROCESS AND REGULATORY COORDINATION

8.1 Interagency Coordination

Table 8.1, together with Table 15.1 of the 1992 GEIS, shows the spectrum of government authorities that oversee various aspects of well drilling and hydraulic fracturing. The 1992 GEIS should be consulted for complete information on the overall role of each agency listed on Table 15.1. Review of existing regulatory jurisdictions and concerns addressed in this revised draft SGEIS identified the following additional agencies that were not previously listed and have been added to Table 8.1:

- NYSDOH;
- USDOT and NYSDOT;
- Office of Parks, Recreation and Historic Preservation (OPRHP);
- NYCDEP; and
- SRBC and DRBC.

Following is a discussion on specific, direct involvement of other agencies in the well permit process relative to high-volume hydraulic fracturing.

8.1.1 Local Governments

ECL §23-0303(2) provides that the Department's Oil, Gas and Solution Mining Law supersedes all local laws relating to the regulation of oil and gas development except for local government jurisdiction over local roads or the right to collect real property taxes. Likewise, ECL §23-1901(2) provides for supersedure of all other laws enacted by local governments or agencies concerning the imposition of a fee on activities regulated by ECL 23.

8.1.1.1 SEQRA Participation

For the following actions which were found in 1992 to be significant or potentially significant under SEQRA, the process will continue to include all opportunities for public input normally provided under SEQRA:

- Issuance of a permit to drill in State Parklands;
- Issuance of a permit to drill within 2,000 feet of a municipal water supply well; and
- Issuance of a permit to drill that will result in disturbance of more than 2.5 acres in an Agricultural District.

Based on the recommendations in this revised draft SGEIS, the Department proposes that the following additional actions will also include all opportunities for public input normally provided under SEQRA:

- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed shallower than 2,000 feet anywhere along the entire proposed length of the wellbore;
- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed where the top of the target fracture zone at any point along the entire proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply;
- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed at a well pad within 500 feet of a principal aquifer (to be re-evaluated two years after issuance of the first permit for high-volume hydraulic fracturing);
- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed on a well pad within 150 feet of a perennial or intermittent stream, storm drain, lake or pond;
- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed and the source water involves a surface water withdrawal not previously approved by the Department that is not based on the NFRM as described in Chapter 7;
- Any proposed water withdrawal from a pond or lake;
- Any proposed ground water withdrawal within 500 feet of a private well;
- Any proposed ground water withdrawal within 500 feet of a wetland that pump test data shows would have an influence on the wetland; and
- Issuance of a permit to drill any well subject to ECL 23 whose location is determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure.

Table 8.1
Regulatory Jurisdictions Associated With High-Volume Hydraulic Fracturing
(Updated August 2011)

Regulated Activity or Impact	DEC Divisions & Offices							NYS Agencies				Federal Agencies			Local Agencies		Other	
	DMN	DEP	DOW	DER	DMM	DFWMR	DAR	DOH	DOT	PSC	OPRHP	EPA	USDOT	Corps	Local Health	Local Govt.	NYC DEP	RBCs
General																		
Well siting	P	-	-	-	-	-	-	-	-	-	*	-	-	-	-	-	*	*
Road use	-	-	-	-	-	-	-	-	A	-	-	-	-	-	-	P	-	-
Surface water withdrawals	S	*	P*	-	-	P	-	-	-	-	-	-	-	-	-	-	-	P*
Stormwater runoff	S	-	P	-	-	-	-	-	-	-	-	-	-	-	-	-	*	*
Wetlands permitting	-	P	-	-	-	S	-	-	-	-	-	-	-	P	-	-	*	*
Transportation of fracturing chemicals	-	-	-	S	-	-	-	-	P	-	-	-	P	-	-		-	-
Well drilling and construction	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	*	-	*
Wellsite fluid containment	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydraulic fracturing/ refracturing	P	-	*	-	-	-	-	*	-	-	-	-	-	-	-	-	-	*
Cuttings and reserve pit liner disposal	P	-	-	A	A	-	-	*	-	-	-	-	-	-	-	-	-	-
Site restoration	P	-	-	-	-	S	-	-	-	-	-	-	-	-	-	-	-	-
Production operations	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gathering lines and compressor stations	S	S	-	-	-	-	S	-	-	P	-	-	-	-	-	-	-	-
Air emissions from all site operations	S	-	-	-	-	-	P*/A*	*	-	-	-	-	-	-	-	-	-	-
Well plugging	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Invasive species control	S	-	-	-	-	P	-	-	-	-	-	-	-	-	-	-	-	-
Fluid Disposal Plan 6NYCRR 554.1(c)(1)																		
Waste transport	-	-	-	P	-	-	-	-	-	-	-	-	-	-	-	*	-	-
POTW disposal	-	*	P	-	-	-	-	-	-	-	-	-	-	-	-	-	*	*
New in-state industrial treatment plants	-	P	S	-	-	-	-	-	-	-	*	-	-	-	-	-	*	*
Injection well disposal	S	P	S	-	-	-	-	-	-	-	-	P	-	-	-	-	-	*
Road spreading	-	-	-	-	P	-	-	*	-	-	-	-	-	-	-	P	-	-
Private Water Wells																		
Baseline testing and ongoing monitoring	P	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Initial complaint response	S	-	-	-	-	-	-	*	-	-	-	-	-	-	P	-	-	-
Complaint follow-up	P	-	-	-	-	-	-	-	-	-	-	-	-	-	S	-	-	-

Key:
P = Primary role
S = Secondary role
A = Advisory role
* = Role pertains in certain circumstances

DEC Divisions
DMN = Division of Mineral Resources
DEP = Division of Environmental Permits (DRA in GEIS Table 15.1)
DOW = Division of Water (DW in GEIS Table 15.1)
DER = Division of Environmental Remediation (DSHW in GEIS Table 15.1)
DMM = Division of Materials Management
DFWMR = Division of Fish, Wildlife and Marine Resources
DAR = Division of Air Resources

8.1.1.2 NYCDEP

The Department will continue to notify NYCDEP of proposed drilling locations in counties with subsurface water supply infrastructure to enable NYCDEP to identify locations in proximity to infrastructure that might require site-specific SEQRA determinations.

8.1.1.3 Local Government Notification

ECL §23-0305(13) requires that the permittee notify any affected local government and surface owner prior to commencing operations. Many local governments have requested notification earlier in the process, although it is not required by law or regulation. The Department would notify local governments of all applications for high-volume hydraulic fracturing in the locality, using a continuously updated database of local government officials and an electronic notification system that would both be developed for this purpose.

8.1.1.4 Road-Use Agreements

The Department strongly encourages operators to reach road use agreements with governing local authorities. The issuance of a permit to drill does not relieve the operator of the responsibility to comply with any local requirements authorized by or enacted pursuant to the New York State Vehicle and Traffic Law. Additional information about road infrastructure and traffic impacts is provided in Sections 6.11 and 7.13.

8.1.1.5 Local Planning Documents

The Department's exclusive authority to issue well permits supersedes local government authority relative to well siting. However, in order to consider potential significant adverse impacts on land use and zoning as required by SEQRA, the EAF Addendum would require the applicant to identify whether the proposed location of the well pad, or any other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies. The applicant would also be required to identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s). For actions where the applicant indicates to the Department that the location of the well pad, or any other activity under the jurisdiction of the Department, is either consistent with local land use laws, regulations, plans or policies, or is not covered by such local land use laws, regulations, plans or policies, the

Department would proceed to permit issuance unless it receives notice of an asserted conflict by the potentially impacted local government.

Applicants for permits to drill are already required to identify whether any additional state, local or federal permits or approvals are required for their projects. Therefore, in cases where an applicant indicates that all or part of their proposed project is inconsistent with local land use laws, regulations, plans or policies, or where the potentially impacted local government advises the Department that it believes the application is inconsistent with such laws, regulations, plans or policies, the Department would, at the time of permit application, request additional information so that it can consider whether significant adverse environmental impacts would result from the proposed project that have not been addressed in the SGEIS and whether additional mitigation or other action should be taken in light of such significant adverse impacts.

8.1.1.6 County Health Departments

As explained in Chapter 15 of the GEIS and Chapter 7 of this document, county health departments are the most appropriate entity to undertake initial investigation of water well complaints. The Department proposes that county health departments retain responsibility for initial response to most water well complaints, referring them to the Department when causes other than those related to drilling have been ruled out. The exception to this is when a complaint is received while active operations are underway within a specified distance; in these cases, the Department will conduct a site inspection and will jointly perform the initial investigation along with the county health department.

8.1.2 State

Except for the Public Service Commission relative to its role regarding pipelines and associated facilities (which will continue; see Section 8.1.2.1), no State agencies other than the Department are listed in GEIS Table 15.1. The NYSDOH, NYSDOT, along with the Office of Parks, Recreation and Historic Preservation, are listed in Table 8.1 and will be involved as follows:

- *NYSDOH:* Potential future and ongoing involvement in review of NORM issues and assistance to county health departments regarding water well investigations and complaints;

- *NYSDOT*: Not directly involved in well permit reviews, but has regulations regarding intrastate transportation of hazardous chemicals found in hydraulic fracturing additives and may advise the Department regarding the required transportation plans and road condition assessments; and

- *OPRHP:* In addition to continued review of well and access road locations in areas of potential historic and archeological significance, OPRHP will also review locations of related facilities such as surface impoundments and treatment plants.

8.1.2.1 Public Service Commission

Article VII, "Siting of Major Utility Transmission Facilities," is the section of the New York Public Service Law (PSL) that requires a full environmental impact review of the siting, design, construction, and operation of major intrastate electric and natural gas transmission facilities in New York State. The Public Service Commission (Commission or PSC) has approval authority over actions involving intrastate electric power transmission lines and high pressure natural fuel gas pipelines, and actions related to such projects. An example of an action related to a high-pressure natural fuel gas pipeline is the siting and construction of an associated compressor station. While the Department and other agencies can have input into the review of an Article VII application or Notice of Intent (NOI) for an action, and can process ancillary permits for federally delegated programs, the ultimate decision on a given project application is made by the Commission. The review and permitting process for natural fuel gas pipelines is separate and distinct from that used by the Department to review and permit well drilling applications under ECL Article 23, and is traditionally conducted after a well is drilled, tested and found productive. For development and environmental reasons, along with early reported anticipated success rates of one hundred percent in 2009, it had been suggested that wells targeting the Marcellus Shale and other low-permeability gas reservoirs using horizontal drilling and high-volume hydraulic fracturing may deserve consideration of pipeline certification by the PSC in advance of drilling to allow pipelines to be in place and operational at the time of the completion of the wells. However, as reported in late 2010 and described below, not all Marcellus Shale wells drilled in neighboring Pennsylvania have proved to be economical when drilled beyond what some have termed the "line of death."[1]

[1] Citizens Voice, Wilkes-Barre, PA., Drillers Take Another Chance in Columbia County, May 9, 2011 http://energy.wilkes.edu/pages/106.asp?item=341.

The PSC's statutory authority has its own "SEQR-like" review, record, and decision standards that apply to major gas and electric transmission lines. As mentioned above, PSC makes the final decision on Article VII applications. Article VII supersedes other State and local permits except for federally authorized permits;[2] however, Article VII establishes the forum in which community residents can participate with members of State and local agencies in the review process to ensure that the application comports with the substance of State and local laws. Throughout the Article VII review process, applicants are strongly encouraged to follow a public information process designed to involve the public in a project's review. Article VII includes major utility transmission facilities involving both electricity and fuel gas (natural gas), but the following discussion, which is largely derived from PSC's guide entitled "The Certification Review Process for Major Electric and Fuel Gas Transmission Facilities,"[3] is focused on the latter. While the focus of PSC's guide with respect to natural gas is the regulation and permitting of transmission lines at least ten miles long and operated at a pressure of 125 psig or greater, the certification process explained in the guide and outlined below provides the basis for the permitting of transmission lines less than ten miles long that would typically serve Marcellus Shale and other low-permeability gas reservoir wells.

Public Service Commission

PSC is the five-member decision-making body established by PSL § 4 that regulates investor-owned electric, natural gas, steam, telecommunications, and water utilities in New York State. The Commission, made up of a Chairman and four Commissioners, decides any application filed under Article VII. The Chairman of the Commission, designated by the Governor, is also the chief executive officer of the Department of Public Service (DPS). Employees of the DPS serve as staff to the PSC.

DPS is the State agency that serves to carry out the PSC's legal mandates. One of DPS's responsibilities is to participate in all Article VII proceedings to represent the public interest.

[2] Article VII does not however supplant the need to obtain property rights from the State for a transmission line project that proposes to cross State-owned land. PSC has no authority, express or implied, to grant land easements, licenses, franchises, revocable consents, or permits to use State land. The Department, therefore, retains the authority to grant or deny access to State lands under its jurisdiction.

[3] http://www.dps.state.ny.us/Article_VII_Process_Guide.pdf.

DPS employs a wide range of experts, including planners, landscape architects, foresters, aquatic and terrestrial ecologists, engineers, and economists, who analyze environmental, engineering, and safety issues, as well as the public need for a facility proposed under Article VII. These professionals take a broad, objective view of any proposal, and consider the project's effects on local residents, as well as the needs of the general public of New York State. Public participation specialists monitor public involvement in Article VII cases and are available for consultation with both applicants and stakeholders.

Article VII

The New York State Legislature enacted Article VII of the PSL in 1970 to establish a single forum for reviewing the public need for, and environmental impact of, certain major electric and gas transmission facilities. The PSL requires that an applicant must apply for a Certificate of Environmental Compatibility and Public Need (Certificate) and meet the Article VII requirements before constructing any such intrastate facility. Article VII sets forth a review process for the consideration of any application to construct and operate a major utility transmission facility. Natural gas transmission lines originating at wells are commonly referred to as "gathering lines" because the lines may collect or gather gas from a single or number of wells which feed a centralized compression facility or other transmission line. The drilling of multiple Marcellus Shale or other low-permeability gas reservoir wells from a single well pad and subsequent production of the wells into one large diameter gathering line eliminates the need for construction and associated cumulative impacts from individual gathering lines if traditionally drilled as one well per location. The PSL defines major natural gas transmission facilities, which statutorily includes many gathering lines, as pipelines extending a distance of at least 1,000 feet and operated at a pressure of 125 psig or more, except where such natural gas pipelines:

- are located wholly underground in a city;
- are located wholly within the right-of-way of a State, county or town highway or village street; or
- replace an existing transmission facility, and are less than one mile long.

Under 6 NYCRR § 617.5(c)(35), actions requiring a Certificate of Environmental Compatibility and Public Need under article VII of the PSL and the consideration of, granting or denial of any such Certificate are classified as "Type II" actions for the purpose of SEQR. Type II actions are those actions, or classes of actions, which have been found categorically to not have significant adverse impacts on the environment, or actions that have been statutorily exempted from SEQR review. Type II actions do not require preparation of an EAF, a negative or positive declaration, or an environmental impact statement (EIS) under SEQR. Despite the legal exemption from processing under SEQR, as previously noted, Article VII contains its own process to evaluate environmental and public safety issues and potential impacts, and impose mitigation measures as appropriate.

As explained in the GEIS, and shown in Table 8.2, PSC has siting jurisdiction over all lines operating at a pressure of 125 psig or more and at least 1,000 feet in length, and siting jurisdiction of lines below these thresholds if such lines are part of a larger project under PSC's purview. In addition, PSC's safety jurisdiction covers all natural gas gathering lines and pipelines regardless of operating pressure and line length. PSC's authority, at the well site, physically begins at the well's separator outlet. The Department's permitting authority over gathering lines operating at pressures less than 125 psig primarily focuses on the permitting of disturbances in environmentally sensitive areas, such as streams and wetlands, and the Department is responsible for administering federally delegated permitting programs involving air and water resources. For all other pipelines regulated by the PSC, the Department's jurisdiction is limited to the permitting of certain federally delegated programs involving air and water resources. Nevertheless, in all instances, the Department either directly imposes mitigation measures through its permits or provides comments to the PSC which, in turn, routinely requires mitigation measures to protect environmentally sensitive areas.

Pre-Application Process

Early in the planning phase of a project, the prospective Article VII applicant is encouraged to consult informally with stakeholders. Before an application is filed, stakeholders may obtain information about a specific project by contacting the applicant directly and asking the applicant to put their names and addresses on the applicant's mailing list to receive notices of public information meetings, along with project updates. After an application is filed, stakeholders may request their names and addresses be included on a project "service list" which is maintained by the PSC. Sending a written request to the Secretary to the PSC to be placed on the service list for a case will allow stakeholders to receive copies of orders, notices and rulings in the case. Such requests should reference the Article VII case number assigned to the application.

Table 8.2 - Intrastate Pipeline Regulation[4]

Pipeline Type	Department	PSC
Gathering <125 psig	Siting jurisdiction only in environmentally sensitive areas where Department permits, other than the well permit, are required. Permitting authority for federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Safety jurisdiction. Public Service Law § 66, 16 NYCRR § 255.9 and Appendix 7-G(a)**.
Gathering ≥125 psig, <1,000 ft.	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Safety jurisdiction. Public Service Law § 66, 16 NYCRR § 255.9 and Appendix 7-G(a)**. Siting jurisdiction also applies if part of larger system subject to siting review. Public Service Law § 66, 16 NYCRR Subpart 85-1.4.
Fuel Gas Transmission* ≥125 psig, ≤1,000 ft., <5 mi., ≤6 in. diameter	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Siting and safety jurisdiction. Public Service Law Sub-Article VII § 121a-2, 16 NYCRR § 255.9 and Appendices 7-D, 7-G and 7-G(a)**. 16 NYCRR Subpart 85-1. EM&CS&P*** checklist must be filed. Service of NOI or application to other agencies required.
Fuel Gas Transmission* ≥125 psig, ≥5 mi., <10 mi. Note: The pipelines associated with wells being considered in this document typically fall into this category, or possibly the one above.	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Siting and safety jurisdiction. Public Service Law Sub-Article VII § 121a-2, 16 NYCRR § 255.9 and Appendices 7-D, 7-G and 7-G(a)**. 16 NYCRR Subpart 85-1. EM&CS&P*** checklist must be filed. Service of NOI or application to other agencies required.
Fuel Gas Transmission* ≥125 psig, ≥10 mi.	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Siting and safety jurisdiction. Public Service Law Article VII § 120, 16 NYCRR § 255.9, 16 NYCRR Subpart 85-2. Environmental assessment must be filed. Service of application to other agencies required.
* Federal Minimum Pipeline Safety Standards 49 CFR Part 192 supersedes PSC if line is closer than 150 ft. to a residence or in an urban area. ** Appendix 7-G(a) is required in all active farm lands. *** EM&CS&P means Environmental Management and Construction Standards and Practices.		

[4] Adapted from the NYSDEC GEIS 1992.