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.

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

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.\textsuperscript{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

\textsuperscript{121} API, 2004; amended 2005., p. 4-3.
sources. A sample calculation showing this methodology for determining combustion emissions (CO₂) from mobile sources is included as Appendix 19, Part B.

Carbon dioxide and CH₄ emissions, the focus of this analysis, are produced from the flaring of natural gas during the well completion phase. Emission rates and calculations from the flaring of natural gas are presented in the previously mentioned 2009 ICF International report. In that report, it was determined that approximately 576 tons of CO₂ and 4.1 tons of CH₄ are emitted each day for a well being flared at a rate of 10 MMcf/d. ICF International’s calculations assumed that 2% of the gas by volume goes uncombusted. ICF International relied on an average composition of Marcellus Shale gas to perform its emissions calculations.

6.6.5 Drilling Rig Mobilization, Site Preparation and Demobilization

Transportation combustion sources are the engines that provide motive power for vehicles used as part of wells site 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 CO₂ emissions. Small quantities of CH₄ and N₂O are also emitted based on fuel composition, combustion conditions, and post-combustion control technology. Estimating emissions from mobile sources is complex, requiring detailed information on the types of mobile sources, fuel types, vehicle fleet age, maintenance procedures, operating conditions and frequency, emissions controls, and fuel consumption. The EPA has developed a software model, MOBILE Vehicle Emissions Modeling Software, that accounts for these factors in calculating exhaust emissions (CO₂, HC, CO, NOₓ, particulate matter, and toxics) for gasoline and diesel fueled vehicles. The preferred approach for estimating CH₄ and N₂O emissions from mobile sources is to assume that these emissions are negligible compared to CO₂.¹²³

An alternative to using modeling software for determining CO₂ emissions for general characterization is to estimate GHG emissions using VMT, which includes a determination of

¹²² ALL Consulting, 2011, Exhibits 19B, 20B.
¹²³ API, 2004; amended 2005, pp. 4-32, 4-33.
estimated fuel usage, or use a fuel usage estimate if available. These methodologies were used to calculate the tons of CO\textsubscript{2} emissions from mobile sources related to the subject activity. A sample CO\textsubscript{2} emissions calculation using fuel consumption is shown in Appendix 19, Part B. Table GHG-2 in Appendix 19, Part A includes CO\textsubscript{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\textsubscript{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\textsubscript{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\textsubscript{2} emission estimates for transporting the completion rig to and from the wellsite. As shown in the table, approximately 4 tons of CO\textsubscript{2} emissions may be generated from a mobilization of the completion rig. For simplification, transportation associated with rig mobilization for the completion rig was assumed to be the same as that for the drilling rig. It is acknowledged that this assumption is conservative.

6.6.7 Well Drilling

Vertical wells may be drilled entirely using compressed air as the drilling fluid or possibly with air for a portion of the well and mud in the target interval. For horizontal wells, drilling activities would typically include the drilling of the vertical and lateral portions of a well using compressed air and mud (or other fluid) respectively. Regardless of the type of well, drilling activities are dependent on the internal combustion engines needed to supply electrical or hydraulic power to: 1) the rotary table or topdrive that turns the drillstring, 2) the drawworks, 3) air compressors, and 4) mud pumps. Carbon dioxide emissions occur from the engines needed to
perform the work required to spud the well and reach its total depth. Table GHG-4 in Appendix 19, Part A includes estimates for 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

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$^{126}$ 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$_2$ emissions of approximately 3 tons and 11 tons, respectively.
Well production may require the removal of production brine from the site which, if present, is stored temporarily in plastic, fiberglass or steel brine production tanks, and then transported off-site for proper disposal or reuse. The trucks used to haul the production brine off-site generate CO₂ emissions. Transportation estimates were used to determine CO₂ emissions from each well development scenario, and emission estimates are presented in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A. Table GHG-10 presents CO₂ and CH₄ emissions for a one-well project for the period of production remaining in the first year after the single vertical well is drilled and completed. For the purpose of this analysis, the duration of production for a single vertical well in its first year was estimated at 349 days (i.e., 365 days minus 16 days to drill & complete) and for a single horizontal well in its first year 331 days (i.e., 365 days minus 34 days to drill & complete). Table GHG-13 shows estimated annual emissions for a single vertical well or single horizontal well commencing in year two, and producing for a full year. Table GHG-12 presents CO₂ and CH₄ emissions for a four-well pad for the period of production remaining in the first year after all ten wells are drilled and completed. For the purpose of this analysis, the duration of production for the ten-well pad in its first year was estimated at 229 days (i.e., 365 days minus 136 days to drill & complete). Instead of work phases occurring sequentially, actual operations may include concurrent well drilling and producing activities on the same well pad. Table GHG-14 shows estimated annual emissions for a four-well project commencing in year two, and producing for a full year.

GHGs in the form of CO₂ and CH₄ are emitted during the well production phase from process equipment and compressor engines. Glycol dehydrators, specifically their vents, which are used to remove moisture from the natural gas in order to meet pipeline specifications and dehydrator pumps, generate vented CH₄ emissions, as do pneumatic device vents which operate by using gas pressure. Compressors used to increase the pressure of the natural gas so that the gas can be put into the sales line typically are driven by engines which combust natural gas. The compressor engine’s internal combustion cycle results in CO₂ emissions while compression of the natural gas generates CH₄ fugitive emissions from leaking packing systems. All packing systems leak under normal conditions, the amount of which depends on cylinder pressure, fitting and alignment of the packing parts, and the amount of wear on the rings and rod shaft.¹²⁷ The emission rates

presented in Table GHG-1, Appendix 19, Part A “Emission Rates for Well Pad” were used to
calculate estimated emissions of CO₂ and CH₄ for each stationary source for a single vertical
well, single horizontal well and four-well pad using the equation noted in Section 6.6.4 and the
corresponding Activity Factors shown in Tables GHG-10, GHG-11, GHG-12, GHG-13 and
GHG-14 in Appendix 19, Part A. Based on the specified emissions rates for each piece of
production equipment, the calculated annual GHG emissions presented in the Tables show that
the compressors, glycol dehydrator pumps and vents contribute the greatest amount of CH₄
emissions during the this phase, while operation of pneumatic device vents also generates vented
CH₄ emissions. The amount of CH₄ vented in the compressor exhaust was not quantified in this
analysis but, according to Volume II: Compressor Driver Exhaust, of the 1996 Final Report on
Methane Emissions from the Natural Gas Industry, compressor exhaust accounts for “about 7.9% of
methane emissions from the natural gas industry.”

6.6.10 Summary of GHG Emissions

As previously discussed, wellsite operations were divided into the following five phases to
facilitate GHG analysis: 1) Drilling Rig Mobilization, Site Preparation and Demobilization, 2)
Completion Rig Mobilization and Demobilization, 3) Well Drilling, 4) Well Completion
(includes hydraulic fracturing and flowback) and 5) Well Production. Each of these phases was
analyzed for potential GHG emissions, with a focus on CO₂ and CH₄ emissions. The results of
these phase-specific analyses for a single vertical well, single horizontal well and four-well pad
are detailed in Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part
A. In addition, the tables include estimates of GHG emissions occurring in the first year and
each producing year thereafter for each project type.

The goal of this review is to characterize and present an estimate of total annual emissions of
CO₂, and other relative GHGs, as both short tons and CO₂e expressed in short tons for
exploration and development of the Marcellus Shale and other low-permeability gas reservoirs
using high volume hydraulic fracturing. To determine CO₂e, each greenhouse gas has been
assigned a number or factor that reflects its global warming potential (GWP). The GWP is a
measure of a compound’s ability to trap heat over a certain lifetime in the atmosphere, relative to
the effects of the same mass of CO₂ released over the same time period. Emissions expressed in
equivalent terms highlight the contribution of the various gases to the overall inventory.
Therefore, GWP is a useful statistical weighting tool for comparing the heat trapping potential of various gases.\textsuperscript{128} For example, Chesapeake Energy Corporation’s July 2009 Fact Sheet on greenhouse gas emissions states that CO\textsubscript{2} has a GWP of 1 and CH\textsubscript{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\textsubscript{2}e.\textsuperscript{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\textsubscript{2}e. Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part A include a summary of estimated CO\textsubscript{2} and CH\textsubscript{4} emissions from the various operational phases as both short tons and as CO\textsubscript{2}e expressed in short tons.

Table 6.27 - Global Warming Potential for Given Time Horizon\textsuperscript{130}

<table>
<thead>
<tr>
<th>Common Name</th>
<th>Chemical Formula</th>
<th>20-Year GWP</th>
<th>100-Year GWP</th>
<th>500-Year GWP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon dioxide</td>
<td>CO\textsubscript{2}</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Methane</td>
<td>CH\textsubscript{4}</td>
<td>72</td>
<td>25</td>
<td>7.6</td>
</tr>
</tbody>
</table>

Table 6.28 is a summary of total estimated CO\textsubscript{2} and CH\textsubscript{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\textsubscript{2}e 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\textsubscript{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\textsubscript{4} emitted is equivalent to 25 tons of CO\textsubscript{2}. Thus, because of its recurring nature, the importance of limiting CH\textsubscript{4} emissions throughout the production phase cannot be overstated.

\textsuperscript{128} API, August 2009. \url{http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf}.


\textsuperscript{130} Adapted from Forster, et al. 2007, Table 2.14. Chapter 2, p. 212. \url{http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf}.
Table 6.28 - Summary of Estimated Greenhouse Gas Emissions (Revised July 2011)

<table>
<thead>
<tr>
<th></th>
<th>CO₂ (tons)</th>
<th>CH₄ (tons)</th>
<th>CH₄ Expressed as CO₂e (tons)¹³¹</th>
<th>Total Emissions from Proposed Activity CO₂e (tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated First-Year Green House Gas Emissions from Single Vertical Well</td>
<td>8,660</td>
<td>246</td>
<td>6,150</td>
<td>14,810</td>
</tr>
<tr>
<td>Estimated First-Year Green House Gas Emissions from Single Horizontal Well</td>
<td>8,761</td>
<td>240</td>
<td>6,000</td>
<td>14,761</td>
</tr>
<tr>
<td>Estimated First-Year Green House Gas Emissions from Four-Well Pad</td>
<td>13,901</td>
<td>402</td>
<td>10,050</td>
<td>23,951</td>
</tr>
<tr>
<td>Estimated Post First-Year Annual Green House Gas Emissions from Single Vertical or Single Horizontal Well</td>
<td>6,164</td>
<td>244</td>
<td>6,100</td>
<td>12,264</td>
</tr>
<tr>
<td>Estimated Post First-Year Annual Green House Gas Emissions from Four-Well Project</td>
<td>6,183</td>
<td>565</td>
<td>14,125</td>
<td>20,300</td>
</tr>
</tbody>
</table>

¹³¹ Equals CH₄ (tons) multiplied by 25 (100-Year GWP).
Some uncertainties remain with respect to quantifying GHG emissions for the subject activity. For the potential associated GHG emission sources, there are multiple options for determining the emissions, often with different accuracies. Table 6.29, which was prepared by the API, illustrates the range of available options for estimating GHG emissions and associated considerations. The two types of approaches used in this analysis were the “Published emission factors” and “Engineering calculations” options. These approaches, as performed, rely heavily on a generic set of assumptions with respect to duration and sequencing of activities, and size, number and type of equipment for operations that would be conducted by many different companies under varying conditions. Uncertainties associated with GHG emission determinations can be the result of three main processes noted below.132

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

Nevertheless, while the results of potential GHG emissions presented in above Table 6.15 may not be precise for each and every well drilled, the real benefit of the emission estimates comes from the identification of likely major sources of CO₂ and CH₄ emissions relative to the activities associated with gas exploration and development. It is through this identification and understanding of key contributors of GHGs that possible mitigation measures and future efforts can be focused in New York. Following, in Chapter 7, is a discussion of possible mitigation measures geared toward reducing GHGs that would be required, with emphasis on CH₄.

### Table 6.29 - Emission Estimation Approaches – General Considerations

<table>
<thead>
<tr>
<th>Types of Approaches</th>
<th>General Considerations</th>
</tr>
</thead>
</table>
| 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$_2$O)                                                                                                                                                                                                                                                                                                                                                           |
| 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.

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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>
<thead>
<tr>
<th>Radionuclide</th>
<th>Half-life</th>
<th>Mode of Decay</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ra-226</td>
<td>1,600 years</td>
<td>alpha</td>
</tr>
<tr>
<td>Rn-222</td>
<td>3.824 days</td>
<td>alpha</td>
</tr>
<tr>
<td>Pb-210</td>
<td>22.30 years</td>
<td>beta</td>
</tr>
<tr>
<td>Po-210</td>
<td>138.40 days</td>
<td>alpha</td>
</tr>
<tr>
<td>Ra-228</td>
<td>5.75 years</td>
<td>beta</td>
</tr>
<tr>
<td>Th-228</td>
<td>1.92 years</td>
<td>alpha</td>
</tr>
<tr>
<td>Ra-224</td>
<td>3.66 days</td>
<td>alpha</td>
</tr>
</tbody>
</table>

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

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:

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>
<thead>
<tr>
<th>Scenarios</th>
<th>Low</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Wells Constructed (Year 1 to Year 30)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal</td>
<td>9,461</td>
<td>37,842</td>
</tr>
<tr>
<td>Vertical</td>
<td>1,071</td>
<td>4,284</td>
</tr>
<tr>
<td>Total</td>
<td>10,532</td>
<td>42,126</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Maximum Number of New Wells Developed per Year (Year 10 to Year 30)</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizontal</td>
</tr>
<tr>
<td>Vertical</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total Employment (in number of FTE jobs)</th>
<th>Low</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Direct Employment Impacts</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Employment(^1)</td>
<td></td>
<td>4,408</td>
<td>17,634</td>
</tr>
<tr>
<td>Production Employment(^2)</td>
<td></td>
<td>1,790</td>
<td>7,161</td>
</tr>
<tr>
<td><strong>Indirect Employment</strong>(^3)</td>
<td></td>
<td>7,293</td>
<td>29,174</td>
</tr>
<tr>
<td><strong>Total Employment Impacts</strong></td>
<td></td>
<td>13,491</td>
<td>53,969</td>
</tr>
<tr>
<td><strong>Total Employment as a Percent of New York State 2010 Labor Force</strong></td>
<td></td>
<td>0.2%</td>
<td>0.7%</td>
</tr>
</tbody>
</table>


\(^1\) 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.
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.
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>
<thead>
<tr>
<th>Scenario</th>
<th>Total Employee Earnings ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
</tr>
<tr>
<td><strong>Direct Earnings Impacts</strong></td>
<td></td>
</tr>
<tr>
<td>Construction Earnings(^1)</td>
<td>$298.4</td>
</tr>
<tr>
<td>Production Earnings(^2)</td>
<td>$121.2</td>
</tr>
<tr>
<td><strong>Indirect Employee Earnings Impacts(^2,3)</strong></td>
<td>$202.3</td>
</tr>
<tr>
<td><strong>Total Employee Earnings Impacts</strong></td>
<td>$621.9</td>
</tr>
<tr>
<td><strong>Total Employee Earnings as a Percent of New York State’s 2009 Total Wages</strong></td>
<td>0.1%</td>
</tr>
</tbody>
</table>


\(^1\) 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>
<thead>
<tr>
<th>Scenarios</th>
<th>Low</th>
<th>Average</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Region A</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Wells Constructed (Year 1 to Year 30)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal</td>
<td>4,743</td>
<td>18,923</td>
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</tr>
<tr>
<td>Vertical</td>
<td>538</td>
<td>2,144</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>5,281</td>
<td>21,067</td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Number of New Wells Developed per Year (Year 10 to Year 30)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal</td>
<td>186</td>
<td>742</td>
<td></td>
</tr>
<tr>
<td>Vertical</td>
<td>21</td>
<td>84</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>207</td>
<td>826</td>
<td></td>
</tr>
<tr>
<td><strong>Region B</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Wells Constructed (Year 1 to Year 30)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal</td>
<td>2,170</td>
<td>8,697</td>
<td></td>
</tr>
<tr>
<td>Vertical</td>
<td>255</td>
<td>993</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>2,425</td>
<td>9,690</td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Number of New Wells Developed per Year (Year 10 to Year 30)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal</td>
<td>85</td>
<td>341</td>
<td></td>
</tr>
<tr>
<td>Vertical</td>
<td>10</td>
<td>39</td>
<td></td>
</tr>
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</table>
### Scenarios

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

---

**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

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Revised Draft SGEIS 2011, Page 6-219
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)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total Employment (in number of FTE jobs)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
</tr>
<tr>
<td><strong>Region A</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Direct Employment Impacts</strong></td>
<td></td>
</tr>
<tr>
<td>Construction Employment</td>
<td>2,204</td>
</tr>
<tr>
<td>Production Employment</td>
<td>895</td>
</tr>
<tr>
<td><strong>Indirect Employment Impacts</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td>650</td>
</tr>
<tr>
<td><strong>Total Employment Impacts</strong></td>
<td>3,749</td>
</tr>
<tr>
<td><strong>Total Employment as a Percentage of Region A’s 2010 Total Labor Force</strong></td>
<td>2.3%</td>
</tr>
<tr>
<td><strong>Region B</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Direct Employment Impacts</strong></td>
<td></td>
</tr>
<tr>
<td>Construction Employment</td>
<td>1,014</td>
</tr>
<tr>
<td>Production Employment</td>
<td>412</td>
</tr>
<tr>
<td><strong>Indirect Employment Impacts</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td>191</td>
</tr>
<tr>
<td><strong>Total Employment Impacts</strong></td>
<td>1,617</td>
</tr>
<tr>
<td><strong>Total Employment as a Percentage of Region B’s 2010 Total Labor Force</strong></td>
<td>1.8%</td>
</tr>
<tr>
<td><strong>Region C</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Direct Employment Impacts</strong></td>
<td></td>
</tr>
<tr>
<td>Construction Employment</td>
<td>221</td>
</tr>
<tr>
<td>Production Employment</td>
<td>90</td>
</tr>
<tr>
<td><strong>Indirect Employment Impacts</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td>66</td>
</tr>
<tr>
<td><strong>Total Employment Impacts</strong></td>
<td>377</td>
</tr>
<tr>
<td><strong>Total Employment as a Percentage of Region C’s 2010 Total Labor Force</strong></td>
<td>0.4%</td>
</tr>
</tbody>
</table>


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)
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)
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)

<table>
<thead>
<tr>
<th></th>
<th>Scenario</th>
<th>Low</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Region A</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Direct Employment Impacts</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Earnings(^1)</td>
<td></td>
<td>$149.2</td>
<td>$597.0</td>
</tr>
<tr>
<td>Production Earnings(^2)</td>
<td></td>
<td>$60.6</td>
<td></td>
</tr>
<tr>
<td><strong>Indirect Earnings Impacts(^3)</strong></td>
<td></td>
<td>$44.0</td>
<td>$176.0</td>
</tr>
<tr>
<td><strong>Total Earnings Impacts</strong></td>
<td></td>
<td>$253.8</td>
<td>$1,015.4</td>
</tr>
<tr>
<td><strong>Total Earnings as a Percentage of Region A’s 2009 Total Wages</strong></td>
<td></td>
<td>4.7%</td>
<td>18.7%</td>
</tr>
<tr>
<td><strong>Region B</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Direct Earnings Impacts</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Earnings(^1)</td>
<td></td>
<td>$68.6</td>
<td>$274.6</td>
</tr>
<tr>
<td>Production Earnings(^2)</td>
<td></td>
<td>$27.9</td>
<td>$111.5</td>
</tr>
<tr>
<td><strong>Indirect Earnings Impacts(^3)</strong></td>
<td></td>
<td>$12.9</td>
<td>$51.6</td>
</tr>
<tr>
<td>Scenario</td>
<td>Low ($ millions)</td>
<td>Average ($ millions)</td>
<td></td>
</tr>
<tr>
<td>----------</td>
<td>-----------------</td>
<td>---------------------</td>
<td></td>
</tr>
<tr>
<td>Total Earnings Impacts</td>
<td>$109.4</td>
<td>$437.7</td>
<td></td>
</tr>
<tr>
<td>Total Earnings as a Percentage of Region B’s 2009 Total Wages</td>
<td>4.8%</td>
<td>19.3%</td>
<td></td>
</tr>
<tr>
<td><strong>Region C</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Direct Earnings Impacts</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Earnings(^1)</td>
<td>$15.0</td>
<td>$59.7</td>
<td></td>
</tr>
<tr>
<td>Production Earnings(^2)</td>
<td>$6.1</td>
<td>$24.2</td>
<td></td>
</tr>
<tr>
<td><strong>Indirect Earnings Impacts</strong>(^3)</td>
<td>$4.5</td>
<td>$17.8</td>
<td></td>
</tr>
<tr>
<td><strong>Total Earnings Impacts</strong></td>
<td>$25.6</td>
<td>$101.7</td>
<td></td>
</tr>
<tr>
<td>Total Earnings as a Percent of Region C’s 2009 Total Wages</td>
<td>0.9%</td>
<td>3.7%</td>
<td></td>
</tr>
</tbody>
</table>


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

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

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

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

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

Impacts on Other Industries

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

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

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

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

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

6.8.2 Population

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

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

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

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

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

The following additional assumptions were used to project population impacts:

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

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

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

- Natural gas development and production would not “crowd out” employment in other unrelated industrial sectors, and employment in these sectors would remain unchanged.
• Job vacancies created when local employees leave existing industries to take jobs in the natural gas extraction industry would be filled.

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

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

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

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

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

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

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

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

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)

<table>
<thead>
<tr>
<th>Production Year</th>
<th>Development Scenario</th>
<th>Transient Population</th>
<th>Permanent Population</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Construction</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>Low</td>
<td>342</td>
<td>256</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>1,370</td>
<td>1,026</td>
</tr>
<tr>
<td>10</td>
<td>Low</td>
<td>2,409</td>
<td>5,277</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>9,639</td>
<td>21,107</td>
</tr>
<tr>
<td>20</td>
<td>Low</td>
<td>1,181</td>
<td>8,519</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>4,725</td>
<td>34,080</td>
</tr>
<tr>
<td>30</td>
<td>Low</td>
<td>441</td>
<td>10,473</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>1,763</td>
<td>41,898</td>
</tr>
<tr>
<td>40</td>
<td>Low</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>50</td>
<td>Low</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>59†</td>
<td>Low</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Note:

† 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)

<table>
<thead>
<tr>
<th>Region</th>
<th>Total 2010 Existing Population</th>
<th>Development Scenario</th>
<th>Maximum Transient Impacts</th>
<th>% Increase from Total Existing 2010 Population</th>
<th>Maximum Permanent Impacts</th>
<th>% Increase from Total Existing 2010 Population</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York State</td>
<td>19,378,102</td>
<td>Low</td>
<td>2,409</td>
<td>&gt;0.1%</td>
<td>15,198</td>
<td>&gt;0.1%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Average</td>
<td>9,639</td>
<td>&gt;0.1%</td>
<td>60,803</td>
<td>0.3%</td>
</tr>
</tbody>
</table>

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)

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

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

<table>
<thead>
<tr>
<th>Year</th>
<th>Transient</th>
<th>Permanent</th>
<th>Total Construction Employment</th>
<th>Transient</th>
<th>Permanent</th>
<th>Total Construction Employment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>79</td>
<td>22</td>
<td>101</td>
<td>315</td>
<td>89</td>
<td>404</td>
</tr>
<tr>
<td>5</td>
<td>349</td>
<td>159</td>
<td>508</td>
<td>1,392</td>
<td>636</td>
<td>2,028</td>
</tr>
<tr>
<td>10</td>
<td>554</td>
<td>460</td>
<td>1,014</td>
<td>2,217</td>
<td>1,839</td>
<td>4,056</td>
</tr>
<tr>
<td>15</td>
<td>405</td>
<td>609</td>
<td>1,014</td>
<td>1,619</td>
<td>2,437</td>
<td>4,056</td>
</tr>
<tr>
<td>20</td>
<td>272</td>
<td>742</td>
<td>1,014</td>
<td>1,087</td>
<td>2,969</td>
<td>4,056</td>
</tr>
<tr>
<td>25</td>
<td>170</td>
<td>844</td>
<td>1,014</td>
<td>681</td>
<td>3,375</td>
<td>4,056</td>
</tr>
<tr>
<td>30</td>
<td>101</td>
<td>913</td>
<td>1,014</td>
<td>406</td>
<td>3,650</td>
<td>4,056</td>
</tr>
</tbody>
</table>
Table 6.42 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region C (New August 2011)

<table>
<thead>
<tr>
<th></th>
<th>Low Scenario</th>
<th></th>
<th>Average Scenario</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Year</td>
<td>Transient</td>
<td>Permanent</td>
<td>Total Construction Employment</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Transient</td>
</tr>
<tr>
<td>1</td>
<td>17</td>
<td>5</td>
<td>22</td>
<td>69</td>
</tr>
<tr>
<td>5</td>
<td>75</td>
<td>35</td>
<td>110</td>
<td>303</td>
</tr>
<tr>
<td>10</td>
<td>121</td>
<td>100</td>
<td>221</td>
<td>482</td>
</tr>
<tr>
<td>15</td>
<td>88</td>
<td>133</td>
<td>221</td>
<td>352</td>
</tr>
<tr>
<td>20</td>
<td>59</td>
<td>162</td>
<td>221</td>
<td>236</td>
</tr>
<tr>
<td>25</td>
<td>37</td>
<td>184</td>
<td>221</td>
<td>148</td>
</tr>
<tr>
<td>30</td>
<td>22</td>
<td>199</td>
<td>221</td>
<td>88</td>
</tr>
</tbody>
</table>

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

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

Notes:
1. Existing population from US Census Bureau’s 2010 Census of Population (USCB 2010).
3. Maximum permanent impacts occur during production Year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

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

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

The lowest maximum potential population impact is found in Region C under the low development scenario, when in Year 10 only 121 unaccompanied, transient construction workers are expected to reside in the region. Under the same development scenario 720 permanent construction and production workers and their families would reside in Region C in Year 30, representing a total of approximately 1.3% of the existing population. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. In contrast, under the average development scenario in Year 30, Region C is projected to have a maximum of 482 unaccompanied, transient construction workers and a maximum of 2,868 permanent construction and production workers and household members in the region. The maximum transient population represents 0.2% of the existing population, and the maximum permanent population represents 1.3% of the existing population. According to population projection figures presented in Section 2.4.11, in the absence of gas well development, Region C is expected to experience a future population decrease and to have a 2030 population of 188,752 persons, a decrease of 26,470 persons, equal to 12.3% of the total existing population. The influx of permanent workers and their family members associated with gas well development, totaling 2,868 persons in Year 30 under the average development scenario, would offset more than 10% of the projected population decline in Region C and would have a small-scale beneficial impact.
Because natural gas wells would not be evenly distributed across the regions, there may be more significant localized population impacts. Depending on the distribution of the wells and the phasing of well development, which depends partly on the price of natural gas, shale gas production may create localized growth in individual small towns. Also, because the development of new wells would not be distributed evenly over time due to swings in well development activity, downswings may cause periods of smaller-than-projected population impacts, while upswings may cause larger-than-projected population impacts.

6.8.3 Housing

This section describes the potential impacts on housing resources and property values that could result from the development of natural gas reserves in low-permeability shale in New York State. Statewide and regional impacts are discussed separately in the following section. For the purposes of this analysis, three representative regions were selected to examine the range of potential regional impacts. This analysis in no way is meant to imply that impacts would occur only in these three regions. Local- and regional-level impacts would occur wherever high-volume hydraulic fracturing wells are constructed. Currently, the actual locations of these wells have not yet been determined, and wells could be sited anywhere there is low-permeability shale.

As described in previous sections, two development scenarios were analyzed for a 60-year period. Only the impacts that would occur during maximum build-out conditions (Year 10 for the transient workers and Year 30 for the permanent workers) are presented in this SGEIS. Impacts for all other years are presented in the Economic Assessment Report.

6.8.3.1 New York State

As previously described in Section 6.8.1 (Economy, Employment, and Income), total construction employment in New York State that would result from the development of low-permeability natural gas reserves is projected to range from 4,408 new workers under the low development scenario to 17,634 new workers under the average development scenario. Initially, the majority of the construction workers are assumed to be temporary, transient workers. As the natural gas fields are developed over time, it is assumed that an increasing number of these workers would become permanent residents. Production employment is projected to range from 1,790 workers under the low development scenario to 7,161 workers under the average development scenario.
Table 6.44 presents estimates of the maximum temporary, transient employment that would occur in Year 10 and the maximum permanent employment that would occur in Year 30. Transient employment includes those construction workers who would only temporarily relocate to the area during well construction. Permanent employment includes permanent construction workers and permanent production workers, as discussed more fully in Section 6.8.2, Population.

Table 6.44 - Maximum\(^1\) Estimated Employment by Development Scenario for New York State (New August 2011)

<table>
<thead>
<tr>
<th>Development Scenario</th>
<th>Transient Employment (FTE)</th>
<th>Permanent(^2) Employment (FTE)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>2,409</td>
<td>5,757</td>
</tr>
<tr>
<td>Average</td>
<td>9,639</td>
<td>23,032</td>
</tr>
</tbody>
</table>

\(^1\) Maximum transient employment occurs in Year 10, while maximum permanent employment occurs in Year 30.

\(^2\) Permanent employment includes both permanent construction and production employment.

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

**Temporary Housing**

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

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

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

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

<table>
<thead>
<tr>
<th>Total Rental Inventory</th>
<th>For Rent</th>
<th>Rental Vacancy Rate (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3,632,743</td>
<td>200,039</td>
<td>5.5</td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th>Total Number of Housing Units</th>
<th>For Sale</th>
<th>For Rent</th>
</tr>
</thead>
<tbody>
<tr>
<td>8,108,103</td>
<td>77,225</td>
<td>200,039</td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th>Region</th>
<th>Maximum Transient Employment (in FTE)(^1)</th>
<th>Maximum Permanent Employment(^2)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Region A</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>1,205</td>
<td>2,879</td>
</tr>
<tr>
<td>Average</td>
<td>4,820</td>
<td>11,517</td>
</tr>
<tr>
<td><strong>Region B</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>554</td>
<td>1,325</td>
</tr>
<tr>
<td>Average</td>
<td>2,217</td>
<td>5,297</td>
</tr>
<tr>
<td><strong>Region C</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>121</td>
<td>289</td>
</tr>
<tr>
<td>Average</td>
<td>482</td>
<td>1,152</td>
</tr>
</tbody>
</table>

\(^1\) 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
hotels/motels 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>
<thead>
<tr>
<th>Region</th>
<th>Total Rental Inventory</th>
<th>For Rent</th>
<th>Rental Vacancy Rate (%)</th>
<th>Hotel/Motel Rooms</th>
</tr>
</thead>
<tbody>
<tr>
<td>Region A</td>
<td>48,955</td>
<td>3,824</td>
<td>7.8</td>
<td>3,110</td>
</tr>
<tr>
<td>Region B</td>
<td>24,558</td>
<td>2,604</td>
<td>10.6</td>
<td>3,705</td>
</tr>
<tr>
<td>Region C</td>
<td>29,127</td>
<td>2,624</td>
<td>9.0</td>
<td>1,987</td>
</tr>
</tbody>
</table>

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 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)

<table>
<thead>
<tr>
<th>Region</th>
<th>Total Number of Housing Units</th>
<th>For Sale</th>
<th>For Rent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Region A</td>
<td>151,135</td>
<td>1,516</td>
<td>3,824</td>
</tr>
<tr>
<td>Region B</td>
<td>111,185</td>
<td>1,989</td>
<td>2,604</td>
</tr>
<tr>
<td>Region C</td>
<td>108,031</td>
<td>1,278</td>
<td>2,624</td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th>Production Year</th>
<th>Annual Production (millions of cubic feet)</th>
<th>Assessed Value of Production</th>
<th>Property Tax Payment&lt;sup&gt;3&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>803.00</td>
<td>$8,985,570</td>
<td>$318,988</td>
</tr>
<tr>
<td>2</td>
<td>354.05</td>
<td>$3,961,820</td>
<td>$140,645</td>
</tr>
<tr>
<td>3</td>
<td>258.00</td>
<td>$2,887,020</td>
<td>$102,489</td>
</tr>
<tr>
<td>4</td>
<td>201.43</td>
<td>$2,253,946</td>
<td>$80,015</td>
</tr>
<tr>
<td>5</td>
<td>165.93</td>
<td>$1,856,701</td>
<td>$65,913</td>
</tr>
<tr>
<td>6</td>
<td>144.50</td>
<td>$1,616,955</td>
<td>$57,402</td>
</tr>
<tr>
<td>7</td>
<td>130.00</td>
<td>$1,454,700</td>
<td>$51,642</td>
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<tr>
<td>8</td>
<td>119.00</td>
<td>$1,331,610</td>
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</tr>
<tr>
<td>9</td>
<td>109.93</td>
<td>$1,230,061</td>
<td>$43,667</td>
</tr>
<tr>
<td>10</td>
<td>103.20</td>
<td>$1,154,850</td>
<td>$40,997</td>
</tr>
<tr>
<td>11</td>
<td>98.04</td>
<td>$1,097,107</td>
<td>$38,947</td>
</tr>
<tr>
<td>12</td>
<td>93.14</td>
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<td>$37,000</td>
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<td>84.06</td>
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<td>75.86</td>
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<td>$30,137</td>
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<tr>
<td>17</td>
<td>72.07</td>
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<td>$28,630</td>
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<td>18</td>
<td>68.47</td>
<td>$766,151</td>
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<td>$24,547</td>
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<td>$656,879</td>
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<td>22</td>
<td>55.77</td>
<td>$624,035</td>
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<td>52.98</td>
<td>$592,833</td>
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<td>24</td>
<td>50.33</td>
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<td>38.94</td>
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</tr>
<tr>
<td>30</td>
<td>37.00</td>
<td>$413,997</td>
<td>$14,697</td>
</tr>
</tbody>
</table>

Total Property Tax Payments for the Productive Life of the Well $1,448,735


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)

<table>
<thead>
<tr>
<th>County:</th>
<th>Broome</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010 Final Gas Unit of Production Value</td>
<td>$11.19</td>
</tr>
<tr>
<td>2010 Overall Full-Value Tax Rate</td>
<td>35.5</td>
</tr>
<tr>
<td>Annual Production (millions of cubic feet)</td>
<td>90</td>
</tr>
<tr>
<td>Assessed Value of Production of Well(^1)</td>
<td>$1,007,100</td>
</tr>
<tr>
<td>Annual Property Tax Payment(^2)</td>
<td>$35,752</td>
</tr>
</tbody>
</table>


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\(^3\) at Peak Production (Year 30), by Region (New August 2011)

<table>
<thead>
<tr>
<th>Region</th>
<th>Low Development Scenario</th>
<th>Average Development Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Change in Assessed Value ($ million)</td>
<td>Total Property Tax Receipts ($ million)</td>
</tr>
<tr>
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</tr>
<tr>
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<tr>
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</tr>
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<td>Total Region B</td>
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<tr>
<td>Region C</td>
<td></td>
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Revised Draft SGEIS 2011, Page 6-261
<table>
<thead>
<tr>
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<th>Average Development Scenario</th>
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<td>Change in Assessed Value ($ million)</td>
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<td><strong>$364</strong></td>
<td><strong>$47,895</strong></td>
<td><strong>$1,451</strong></td>
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</table>


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

Note: Totals may not sum due to rounding.

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

In addition to the positive fiscal impacts discussed above, local governments would also experience some significant negative fiscal impacts resulting from the development of natural gas reserves in the low-permeability shale. As described in previous sections, the use of high-volume hydraulic-fracturing drilling techniques would increase the demand for governmental services and thus increase the total expenditures of local government entities. Additional road construction, improvement, and repair expenditures would be required as a result of the increased truck traffic that would occur. Additional expenditures on emergency services such as fire, police, and first aid would be expected as a result of the increased traffic and construction and production activities. Also additional expenditures on public water supply systems may also be required. Finally, if substantial in-migration occurs in the region as a result of drilling and production, local governments would be required to increase expenditures on other services, such as education, health and welfare, recreation, housing, and solid waste management to serve the additional population.
6.8.5 Environmental Justice

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

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

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

6.9 Visual Impacts¹³⁵

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

¹³⁵ Section 6.9, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.
The visual impacts of horizontal drilling and high-volume hydraulic fracturing would result from four general on-site processes associated with the development of viable well locations: construction, well development (drilling and fracturing), operation or production, and post-production reclamation. The greatest visual impacts would be associated with the construction of well pads and associated facilities, which would create new long-term features within surrounding landscapes, and well drilling and completion activities at viable well locations, which would be temporary and short-term in nature. Additional off-site activities could also result in visual impacts, including the presence of increased workforce personnel and vehicular traffic, and the use of existing or development of new off-site staging areas or contractor/storage yards.

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

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

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

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

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

6.9.1.3 Duration and Nature of Drilling and Hydraulic-Fracturing Activities

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

Since 1992 the industry has been trending, where possible, toward the development of multi-well pads rather than single-well pads. Multi-well pads are slightly larger, but the equipment used is often the same. Based on current industry practice, a taller rig (170 feet in total height) with a larger footprint and substructure may be used to drill multiple wells from a single pad. In some instances, smaller rigs may be used to drill the initial hole and conductor casing to just above the kick-off point, the depth at which a vertical borehole begins to turn into a horizontal borehole. The larger rig is then used for the final horizontal portion of the hole. Typically, one or two wells are drilled and the rig is then removed.
If the well(s) are productive, the rig is brought back and the remaining wells are drilled and stimulated by the injection of hydraulic fracturing additives. There is the possibility that all wells on a pad would be drilled, stimulated, and completed consecutively, reducing the duration of visual impacts that would occur during drilling and hydraulic-fracturing activities. However, state law requires that all wells on a multi-well pad be drilled within three years of starting the first well (NTC 2011).

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

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

6.9.2.1 New Landscape Features Associated with the Construction of Well Pads

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

Photo 6.1 below shows a well site where wells have already been drilled and completion operations are underway. The photograph shows evidence of grading, cutting, and filling
activities; the use of gravel for site preparation; and mulching along an earthen embankment to prevent erosion—all activities implemented during construction activities. A portion of a newly created linear right-of-way for a connecting pipeline is shown on the hillside in the background of the photo. The red and blue tanks shown in Photo 6.1 are discussed in greater detail in Section 6.9.2.2.

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

Photo 6.2 below shows the same recently constructed well pad that is currently under development, but from a different angle. In the foreground of the photograph below, the newly created access road leading to the well pad is shown. Erosion control measures and materials are also shown in the photograph, including channeling, gravel fill and hay bales in the channel, and mulching on topsoil or spoil piles to the left of the access road to minimize erosion. Additional views of access roads are presented in Photos 5.1 through 5.4 in Section 5.1.1 and in Photo 6.2. Tanks, vehicles, and other equipment are discussed in greater detail in Section 6.9.2.2.
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.
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.
Additional areas associated with the construction of well sites would include newly created access roads and pipeline rights-of-way for connector pipelines (see Photo 6.1 and Photo 6.2). These sites would typically be narrow, linear features, as opposed to the large open areas needed for well pads and water impoundment or procurement sites.

6.9.2.2 New Landscape Features Associated with Drilling Activities at Well Pads

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

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

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

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

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

The equipment typically present during hydraulic fracturing includes the following:

- storage tanks that contain the water and additives used for hydraulic fracturing (rectangular red tanks on well site shown in Photo 6.5);

- tanks containing chemicals used in the fracturing process or for storage of liquefied natural gas produced during hydraulic fracturing (blue rectangular tanks on well site shown in Photo 6.5);

- compressors (large cylindrical blue equipment and smaller dark green equipment with stacks or vents shown in Photo 6.5) used for pumping product through various hoses and pipelines;

- miscellaneous trucks, including tractor trailers and other large trucks for hauling sand and hydraulic fracturing additives, pipe-hauling trucks, welding and other mechanical support trucks, and a crane; and

- miscellaneous worker vehicles (almost all of the white or silver vehicles shown in Photo 6.5).
6.9.2.4 New Landscape Features Associated with Production at Viable Well Sites

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

6.9.2.5 New Landscape Features Associated with the Reclamation of Well Sites

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

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

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

- construction-related impacts associated with the preparation of drill sites, including the construction of access roads, connecting pipelines, and other ancillary facilities; work during this phase progresses in a linear fashion, with impacts at any one location occurring for up to several weeks;
- development-related impacts associated with the drilling of wells, including the presence of drill rigs and equipment during the drilling phase; work during this phase progresses over an approximately 2- to 3-week period;

- development-related impacts associated with the fracturing of wells, including the presence of storage tanks, compressors, trucks, and other equipment that supports fracturing activities; work during this phase progresses over an approximately 2- to 3-week period;

- operational impacts associated with active well sites, which include the presence of production equipment if the well site is viable; this low-impact phase involves small pieces of equipment and pipeline connections for up to 30 years; and

- reclamation impacts associated with the removal of production equipment and the restoration of well site locations when operations are complete.

6.9.3.1 Visual Impacts Associated with Construction of Well Pads

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

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

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

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

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

Fracturing-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.4 would result from the introduction of new and visible landscape features and activities into the existing settings that surround well locations. During fracturing activities, such landscape features would include the newly created well pad sites, including: associated access roads, pipeline rights-of-way, and other aboveground site facilities or structures such as water impoundment areas; on-site equipment such storage vessels, trucks, and other equipment within containment areas; and buildings or other aboveground structures. On-site equipment would be the most visible sign of fracturing activity and, when viewed from relatively short distances (i.e., from 1,000 feet to 0.5 miles) are relatively prominent landscape features. Additional new and visible landscape features would include traffic related to the development of wells, including worker vehicles and heavy equipment used at each well site.

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

6.9.3.4 Visual Impacts Associated with Production at Well Sites

Operations-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.4 would result from extraction activities at viable well sites. The visual impacts of production would be less intrusive in surrounding landscapes, primarily because minimal on-site equipment is necessary during productions. Well site locations would consist of large, level
grassy or graveled areas, with wellhead locations and small aboveground facilities for extraction and transfer of product into gas lines. Thousands of similar wellhead installations are already present in the area underlain by the Marcellus and Utica Shales in New York and may be considered relatively unobtrusive landscape features (see Photos 6.11 through 6.20 at the end of Chapter 6). Although there would be some traffic associated with operations, including worker vehicles and equipment needed for operation and maintenance activities, the presence of such traffic would be substantially less than the traffic generated during construction and development (drilling and fracturing) of the wells.

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

**6.9.3.5 Visual Impacts Associated with the Reclamation of Well Sites**

Reclamation-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.4 would result from the removal of on-site well equipment and structures and from site restoration activities. Site restoration activities would include recontouring the terrain at well sites to reestablish pre-existing topographic conditions and planting appropriate vegetative cover to reestablish appropriate site-specific vegetation species and growth patterns. Subsequent periodic reclamation-related visual impacts may also result from post-restoration inspection or monitoring and measures needed to ensure the successful reestablishment and succession of vegetation.
Reclamation-related visual impacts would be direct (i.e., directly impact the existing visual
setting of a well location) and indirect (i.e., indirectly impact the existing settings within
viewsheds that would contain a well location, including views of and from visual resources or
visually sensitive areas that would also contain a well location). The duration of these temporary
impacts would range from short term to long term. For example, removing well equipment and
structures, recontouring the terrain, and replanting appropriate vegetation to reestablish pre-
existing conditions would be of short-term duration (a matter of weeks or months). However,
reclamation of forested areas may be of long-term duration.

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

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

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

Section 6.9.3 discusses the nature of impacts on visual resources or visually sensitive areas that
may be associated with on-site horizontal drilling and hydraulic-fracturing activities. However,
off-site activities that could occur during one or more of the construction, development (drilling
and fracturing), production, and reclamation phases also may result in additional indirect impacts
on visual resources or visually sensitive areas, particularly during the periodic influx of
specialized workforces during various phases of development. Such off-site activities may
include changes in traffic volumes and patterns, depending on the phase of development.
occurring at one or more well sites in an area; and the development and/or use of existing or new contractor yards or equipment storage areas or other staging areas that may be necessary at various times (Upadhyay and Bu 2010).

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

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

Additional cumulative visual impacts from traffic during the construction and development (drilling and fracturing) phase may occur where a number of wells are developed near each other at the same time, resulting in increased amounts of traffic. For areas with multiple well sites, this potential increase in traffic during the construction and development (drilling and fracturing) phase could increase the extent and duration of cumulative visual impacts. This potential cumulative visual impact from traffic used to construct and develop multiple well sites in an area might be reduced if the same operator develops multiple pads, because the same equipment may be used in phases to reduce the overall need and cost for the movement of equipment and materials.
The development of new and/or use of existing contractor yards or equipment storage areas or other staging areas may be necessary at various times during the construction, development (drilling and fracturing), and reclamation phases. Such areas may have a congested appearance during their use. If existing, previously developed contractor/storage yards or staging areas are used for such activities, their temporary and periodic use would be consistent with their existing setting and would have no new impact on visual resources or visually sensitive areas. However, if new yards or staging areas have to be created, the temporary and periodic use of such areas may represent a new impact on visual resources or visually sensitive areas.

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

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

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

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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.\textsuperscript{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

\textsuperscript{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)

<table>
<thead>
<tr>
<th>Description of Activity</th>
<th>Description of Typical New Landscape Features</th>
<th>Description of Potential Visual Impacts</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>On-site Well Pad Construction</strong></td>
<td>• Newly created well pads - open, level areas averaging approximately 3.5 acres in size&lt;br&gt;• Newly created linear features such as access roads and connecting pipelines&lt;br&gt;• Newly created water impoundment areas (if necessary)&lt;br&gt;• Construction equipment, including bulldozers, graders, backhoes, and other large equipment for clearing, cutting, filling and grading activities&lt;br&gt;• Trucks for hauling equipment and materials&lt;br&gt;• Worker vehicles</td>
<td>• Direct impacts - on the existing visual setting of a well location&lt;br&gt;• Indirect impacts - on the existing visual setting of areas in the vicinity of a well location, including views that contain a well location&lt;br&gt;• Temporary or short-term duration - during the weeks or months while construction is underway&lt;br&gt;• Negative - because of the introduction of new features into the landscape&lt;br&gt;• Site-specific - within views that contain individual well locations&lt;br&gt;• Cumulative - within views of areas or regions that contain concentrations of well locations</td>
</tr>
<tr>
<td><strong>On-site Well Drilling</strong></td>
<td>• Drill rigs of varying heights and dimensions&lt;br&gt;• 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&lt;br&gt;• Trucks for hauling equipment and materials&lt;br&gt;• Worker vehicles</td>
<td>• Direct impacts - on the existing visual setting of a well location&lt;br&gt;• Indirect impacts - on the existing visual settings of areas surrounding a well location, including views that include a well location&lt;br&gt;• Temporary - during the weeks while drilling is underway&lt;br&gt;• 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&lt;br&gt;• Negative - throughout the duration of drilling, primarily because of the high visibility of drilling activities from surrounding vantage points&lt;br&gt;• Site-specific - within views that contain individual well locations&lt;br&gt;• Cumulative – within views of areas or regions that contain concentrations of well locations</td>
</tr>
<tr>
<td>Description of Activity</td>
<td>Description of Typical New Landscape Features</td>
<td>Description of Potential Visual Impacts</td>
</tr>
<tr>
<td>-------------------------</td>
<td>----------------------------------------------</td>
<td>----------------------------------------</td>
</tr>
</tbody>
</table>
| **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 |
<table>
<thead>
<tr>
<th>Description of Activity</th>
<th>Description of Typical New Landscape Features</th>
<th>Description of Potential Visual Impacts</th>
</tr>
</thead>
</table>
| 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 |
<table>
<thead>
<tr>
<th>Description of Activity</th>
<th>Description of Typical New Landscape Features</th>
<th>Description of Potential Visual Impacts</th>
</tr>
</thead>
</table>
| 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 |

Revised Draft SGEIS 2011, Page 6-288
6.10 Noise

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:

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

$$L_{p1} = L_{p2} + 10 \log(U.F./10) - 20 \log(d2/d1):$$

where:

- $L_{p1}$ = the average noise level (dBA) at a distance (d2) due to the operation of a unit of equipment throughout the day;
- $L_{p2}$ = 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:
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.

\[
Leq_{total} = 10 \log \left( 10^{\frac{Leq_1}{10}} + 10^{\frac{Leq_2}{10}} + 10^{\frac{Leq_3}{10}} \ldots etc. \right)
\]
### Table 6.54 - Estimated Construction Noise Levels at Various Distances for Access Road Construction (New August 2011)

<table>
<thead>
<tr>
<th>Construction Equipment</th>
<th>Quantity</th>
<th>Usage Factor %</th>
<th>( \text{L}_{\text{max}} ) SPL @ 50 Feet (dBA)</th>
<th>Distance in Feet/SPL (dBA)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>( \text{L}_{\text{max}} ) adj.</td>
<td>50</td>
</tr>
<tr>
<td>Excavator</td>
<td>2</td>
<td>40</td>
<td>81</td>
<td>80</td>
</tr>
<tr>
<td>Grader</td>
<td>2</td>
<td>40</td>
<td>85</td>
<td>84</td>
</tr>
<tr>
<td>Bulldozer</td>
<td>2</td>
<td>40</td>
<td>82</td>
<td>81</td>
</tr>
<tr>
<td>Compactor</td>
<td>2</td>
<td>20</td>
<td>83</td>
<td>79</td>
</tr>
<tr>
<td>Water truck</td>
<td>2</td>
<td>40</td>
<td>76</td>
<td>75</td>
</tr>
<tr>
<td>Dump truck</td>
<td>8</td>
<td>40</td>
<td>76</td>
<td>81</td>
</tr>
<tr>
<td>Loader</td>
<td>2</td>
<td>40</td>
<td>79</td>
<td>78</td>
</tr>
<tr>
<td><strong>Composite Noise Level</strong></td>
<td></td>
<td></td>
<td><strong>89</strong></td>
<td><strong>75</strong></td>
</tr>
</tbody>
</table>

Source: FHWA 2006.

Key:
- \( \text{adj} \) = adjusted.
- dBA = A-weighted decibels.
- \( \text{L}_{\text{max}} \) = 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)

<table>
<thead>
<tr>
<th>Construction Equipment</th>
<th>Quantity</th>
<th>Usage Factor %</th>
<th>Lmax SPL @ 50 Feet (dBA)</th>
<th>Distance in Feet/SPL (dBA)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>50 (adj.)</td>
</tr>
<tr>
<td>Excavator</td>
<td>1</td>
<td>40</td>
<td>81</td>
<td>77</td>
</tr>
<tr>
<td>Bulldozer</td>
<td>1</td>
<td>40</td>
<td>82</td>
<td>78</td>
</tr>
<tr>
<td>Water truck</td>
<td>1</td>
<td>40</td>
<td>76</td>
<td>72</td>
</tr>
<tr>
<td>Dump truck</td>
<td>2</td>
<td>40</td>
<td>76</td>
<td>75</td>
</tr>
<tr>
<td>Pickup truck</td>
<td>2</td>
<td>40</td>
<td>75</td>
<td>74</td>
</tr>
<tr>
<td>Chain saw</td>
<td>2</td>
<td>20</td>
<td>84</td>
<td>80</td>
</tr>
<tr>
<td>Composite Noise Level</td>
<td></td>
<td></td>
<td></td>
<td>84</td>
</tr>
</tbody>
</table>

Source: FHWA 2006.

Key:
- adj = adjusted.
- dBA = A-weighted decibels.
- $L_{\text{max}}$ = 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 wellbore. 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)

<table>
<thead>
<tr>
<th>Construction Equipment</th>
<th>Quantity</th>
<th>Sound Power Level (dBA)</th>
<th>Distance in Feet/SPL(^1) (dBA)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>50 (adj.)</td>
</tr>
<tr>
<td>Drill rig drive engine</td>
<td>1</td>
<td>105</td>
<td>71</td>
</tr>
<tr>
<td>Compressors</td>
<td>4</td>
<td>105</td>
<td>77</td>
</tr>
<tr>
<td>Hurricane booster</td>
<td>3</td>
<td>81</td>
<td>51</td>
</tr>
<tr>
<td>Compressor exhaust</td>
<td>1</td>
<td>85</td>
<td>51</td>
</tr>
<tr>
<td><strong>Composite Noise Level</strong></td>
<td></td>
<td></td>
<td>79</td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th>Construction Equipment</th>
<th>Quantity</th>
<th>Sound Level</th>
<th>Distance</th>
<th>Distance in Feet/SPL (dBA)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>50 (adj.)</td>
<td>250</td>
</tr>
<tr>
<td>Rig drive motor</td>
<td>1</td>
<td>105(^2)</td>
<td>0</td>
<td>71</td>
</tr>
<tr>
<td>Generator</td>
<td>3</td>
<td>81(^2)</td>
<td>0</td>
<td>51</td>
</tr>
<tr>
<td>Top drive</td>
<td>1</td>
<td>85(^4)</td>
<td>5</td>
<td>65</td>
</tr>
<tr>
<td>Draw works</td>
<td>1</td>
<td>74(^4)</td>
<td>10</td>
<td>60</td>
</tr>
<tr>
<td>Triple shaker</td>
<td>1</td>
<td>85(^4)</td>
<td>15</td>
<td>75</td>
</tr>
<tr>
<td><strong>Composite Noise Level</strong></td>
<td></td>
<td></td>
<td>76</td>
<td>62</td>
</tr>
</tbody>
</table>

Source: Confidential Industry Source.

\(^1\) SPL = Sound Pressure Level

Key:

adj = adjusted to quantity.
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.\textsuperscript{139}

\textbf{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

\textsuperscript{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)

<table>
<thead>
<tr>
<th>Construction Equipment</th>
<th>Quantity</th>
<th>SPL (^1) (dBA)</th>
<th>Distance (feet)</th>
<th>Quantity Adjusted Sound Level</th>
<th>Distance in Feet/SPL (^1) (dBA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pumper truck</td>
<td>20</td>
<td>110</td>
<td>3</td>
<td>123</td>
<td>99 85 79 73 69 67</td>
</tr>
<tr>
<td>Pumper truck</td>
<td>20</td>
<td>115</td>
<td>3</td>
<td>128</td>
<td>104 90 84 78 74 72</td>
</tr>
</tbody>
</table>

Source: Confidential Industry Source.

\(^1\) SPL = Sound Pressure Level
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>
<thead>
<tr>
<th>Operation</th>
<th>Estimated Duration (days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Access roads</td>
<td>3 - 7</td>
</tr>
<tr>
<td>Site preparation/well pad</td>
<td>7 - 14</td>
</tr>
<tr>
<td>Well drilling</td>
<td>28 - 35</td>
</tr>
<tr>
<td>Hydraulic fracturing single well</td>
<td>2 - 5</td>
</tr>
</tbody>
</table>
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

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

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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)

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

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)

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

Source: All Consulting 2010.

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

<table>
<thead>
<tr>
<th>Horizontal Well with High-Volume Hydraulic Fracturing</th>
<th>Vertical Well</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Heavy Truck</td>
</tr>
<tr>
<td>Light-duty trips</td>
<td>831</td>
</tr>
<tr>
<td>Heavy-duty trips</td>
<td>1,148</td>
</tr>
<tr>
<td><strong>Combined Total</strong></td>
<td><strong>1,975</strong></td>
</tr>
<tr>
<td><strong>Total Vehicle Trips</strong></td>
<td><strong>3,950</strong></td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th>Counties</th>
<th>Region A</th>
<th>Region B</th>
<th>Region C</th>
<th>Rest of New York State</th>
<th>State-Wide Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low Development Scenario</td>
<td>Average Development Scenario</td>
<td>High Development Scenario</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Year</td>
<td>Horizontal</td>
<td>Vertical</td>
<td>Total</td>
<td>Horizontal</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>4,334</td>
<td>226</td>
<td>4,561</td>
<td>2,055</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>21,216</td>
<td>1,245</td>
<td>22,460</td>
<td>9,809</td>
</tr>
<tr>
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<td>10</td>
<td>42,431</td>
<td>2,376</td>
<td>44,807</td>
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<td>2,376</td>
<td>44,807</td>
<td>19,391</td>
</tr>
</tbody>
</table>

Revised Draft SGEIS 2011, Page 6-309
Table 6.64 - Illustrative AADT Range for State Roads (New August 2011)

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

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\textsuperscript{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

\textsuperscript{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

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.

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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...
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.
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.

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.
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.
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.

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.
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.

![Well #11 (Hole number 22831)](image1)

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.

![Well #12 (Hole number 22871)](image2)

Henkel 10/22/2002

Henkel 5/6/2009
Chapter 7

Mitigation Measures
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Chapter 7 – Mitigation Measures

CHAPTER 7 EXISTING AND RECOMMENDED MITIGATION MEASURES .............................................................. 7-1

7.1 PROTECTING WATER RESOURCES ........................................................................................................... 7-1
  7.1.1 Water Withdrawal Regulatory and Oversight Programs ................................................................. 7-2
    7.1.1.1 Department Jurisdictions ........................................................................................................... 7-2
    7.1.1.2 Other Jurisdictions - Great Lakes-St. Lawrence River Basin Water Resources Compact ........... 7-5
    7.1.1.3 Other Jurisdictions - River Basin Commissions ..................................................................... 7-6
    7.1.1.4 Impact Mitigation Measures for Surface Water Withdrawals .............................................. 7-14
    7.1.1.5 Impact Mitigation Measures for Groundwater Withdrawals .............................................. 7-24
    7.1.1.6 Cumulative Water Withdrawal Impacts .............................................................................. 7-25
  7.1.2 Stormwater .............................................................................................................................................. 7-26
    7.1.2.1 Construction Activities ......................................................................................................... 7-30
    7.1.2.2 Industrial Activities ............................................................................................................. 7-30
    7.1.2.3 Production Activities .......................................................................................................... 7-31
  7.1.3 Surface Spills and Releases at the Well Pad ......................................................................................... 7-32
    7.1.3.1 Fueling Tank and Tank Refilling Activities ....................................................................... 7-33
    7.1.3.2 Drilling Fluids ....................................................................................................................... 7-35
    7.1.3.3 Hydraulic Fracturing Additives ............................................................................................ 7-38
    7.1.3.4 Flowback Water .................................................................................................................. 7-39
    7.1.3.5 Primary and Principal Aquifers ............................................................................................ 7-40
  7.1.4 Potential Ground Water Impacts Associated With Well Drilling and Construction ......................... 7-42
    7.1.4.1 Private Water Well Testing .................................................................................................. 7-44
    7.1.4.2 Sufficiency of As-Built Wellbore Construction .................................................................... 7-49
    7.1.4.3 Annular Pressure Buildup .................................................................................................... 7-55
  7.1.5 Setback from FAD Watersheds ............................................................................................................. 7-55
  7.1.6 Hydraulic Fracturing Procedure ........................................................................................................... 7-56
  7.1.7 Waste Transport .................................................................................................................................... 7-59
    7.1.7.1 Drilling and Production Waste Tracking Form ...................................................................... 7-59
    7.1.7.2 Road Spreading ................................................................................................................... 7-60
    7.1.7.3 Flowback Water Piping ....................................................................................................... 7-61
    7.1.7.4 Use of Tanks Instead of Impoundments for Centralized Flowback Water Storage ............. 7-61
    7.1.7.5 Closure Requirements .......................................................................................................... 7-62
  7.1.8 SPDES Discharge Permits ..................................................................................................................... 7-62
    7.1.8.1 Treatment Facilities .......................................................................................................... 7-63
    7.1.8.2 Disposal Wells ..................................................................................................................... 7-65
  7.1.9 Solids Disposal ........................................................................................................................................ 7-66
  7.1.10 Protecting NYC’s Subsurface Water Supply Infrastructure ............................................................ 7-68
  7.1.11 Setbacks ................................................................................................................................................ 7-69
    7.1.11.1 Setbacks from Groundwater Resources ............................................................................ 7-71
    7.1.11.2 Setbacks from Other Surface Water Resources .................................................................. 7-74

7.2 PROTECTING FLOODPLAINS ..................................................................................................................... 7-76

7.3 PROTECTING FRESHWATER WETLANDS .................................................................................................. 7-76

7.4 MITIGATING POTENTIAL SIGNIFICANT IMPACTS ON ECOSYSTEMS AND WILDLIFE ....................... 7-77
  7.4.1 Protecting Terrestrial Habitats and Wildlife ...................................................................................... 7-77
    7.4.1.1 BMPs for Reducing Direct Impacts at Individual Well Sites .................................................. 7-77
    7.4.1.2 Reducing Indirect and Cumulative Impacts of Habitat Fragmentation .................................. 7-79
    7.4.1.3 Monitoring Changes in Habitat ............................................................................................. 7-87
  7.4.2 Invasive Species ..................................................................................................................................... 7-88
    7.4.2.1 Terrestrial .............................................................................................................................. 7-89
7.4.2.2 Aquatic ................................................................. 7-92
7.4.3 Protecting Endangered and Threatened Species ................................................................. 7-98
7.4.4 Protecting State-Owned Land ................................................................................... 7-100

7.5 MITIGATING AIR QUALITY IMPACTS ................................................................. 7-101

7.5.1 Mitigation Measures Resulting from Regulatory Analysis (Internal Combustion Engines and Glycol Dehydrators) ................................................................. 7-102
7.5.1.1 Control Measures for Nitrogen Oxides-$NO_x$ ................................................................ 7-102
7.5.1.2 Control Measures for Sulfur Oxides - $SO_x$ .................................................................. 7-105
7.5.1.3 Natural Gas Production Facilities Subject to NESHAP 40 CFR Part 63, Subpart HH (Glycol Dehydrators) ................................................................. 7-106

7.5.2 Mitigation Measures Resulting from Air Quality Impact Assessment and Regional Ozone Precursor Emissions ........................................................................ 7-107

7.5.3 Summary of Mitigation Measures to Protect Air Quality ...................................................... 7-108
7.5.3.1 Well Pad Activity Mitigation Measures ........................................................................... 7-108
7.5.3.2 Mitigation Measures for Off-Site Gas Compressors ......................................................... 7-110

7.6 MITIGATING GHG EMISSIONS ......................................................................... 7-110

7.6.1 General ........................................................................ 7-110
7.6.2 Site Selection .................................................................. 7-111
7.6.3 Transportation .................................................................. 7-111
7.6.4 Well Design and Drilling .................................................. 7-112
7.6.5 Well Completion .................................................................. 7-112
7.6.6 Well Production .................................................................. 7-113
7.6.7 Leak and Detection Repair Program ............................................................................. 7-114
7.6.8 Mitigating GHG Emissions Impacts - Conclusion .......................................................... 7-116

7.7 MITIGATING NORM IMPACTS ..................................................................... 7-117

7.7.1 State and Federal Responses to Oil and Gas NORM .............................................................. 7-117
7.7.2 Regulation of NORM in New York State .......................................................................... 7-118

7.8 SOCIOECONOMIC MITIGATION MEASURES .............................................. 7-120

7.9 VISUAL MITIGATION MEASURES ................................................................. 7-121

7.9.1 Design and Siting Measures ................................................................................ 7-122
7.9.2 Maintenance Activities ......................................................................................... 7-126
7.9.3 Decommissioning ................................................................................................. 7-127
7.9.4 Offsetting Mitigation .............................................................................................. 7-128

7.10 NOISE MITIGATION MEASURES .............................................................. 7-128

7.10.1 Pad Siting Equipment, Layout and Operation .................................................................. 7-128
7.10.2 Access Road and Traffic Noise ...................................................................................... 7-129
7.10.3 Well Drilling and Hydraulic Fracturing ......................................................................... 7-130
7.10.4 Conclusion ................................................................................................................ 7-134

7.11 TRANSPORTATION MITIGATION MEASURES .................................. 7-135

7.11.1 Mitigating Damage to Local Road Systems ................................................................... 7-135
7.11.1.1 Development of Transportation Plans, Baseline Surveys, and Traffic Studies ................ 7-136
7.11.1.2 Municipal Control over Local Road Systems ............................................................... 7-137
7.11.1.3 Road Use Agreements ................................................................................................. 7-138
7.11.1.4 Reimbursement for Costs Associated with Local Road Work .................................... 7-139
7.11.2 Mitigating Incremental Damage to the State System of Roads ....................................... 7-140
7.11.3 Mitigating Operational and Safety Impacts on Road Systems ......................................... 7-141
7.11.4 Other Transportation Mitigation Measures ..................................................................... 7-142
7.11.5 Mitigating Impacts from the Transportation of Hazardous Materials ................................ 7-142

Revised Draft SGEIS 2011, Page 7-ii
7.11.6 Mitigating Impacts on Rail and Air Travel................................................................. 7-143

7.12 COMMUNITY CHARACTER MITIGATION MEASURES ..........................................................7-144

7.13 EMERGENCY RESPONSE PLAN ........................................................................................7-146

FIGURES
Figure 7.1 - Hydrologic Regions of New York (New July 2011) (Taken from Lumia et al, 2006) .......................... 7-21
Figure 7.2 - Key Habitat Areas for Protecting Grassland and Interior Forest Habitats (Updated August 2011)..... 7-80
Figure 7.3 - Scaling Factors for Matrix Forest Systems in the High Allegheny Ecoregion (New July 2011) ............ 7-84

TABLES
Table 7.1 - Regulations Pertaining to Watershed Withdrawal (Revised July 2011)............................................. 7-7
Table 7.2 - Regional Passby Flow Coefficients (cfs/sq. mi.) (Updated August 2011)............................................... 7-22
Table 7.3 - NYSDOH Water Well Testing Recommendations ............................................................................. 7-46
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) ........................................................................................................ 7-81
Table 7.5 - Summary of Regulations Pertaining to Transfer of Invasive Species ................................................. 7-94
Table 7.6 - Required Well Pad Stack Heights to Prevent Exceedances.............................................................. 7-109

PHOTOS
Photo 7.1 - View of a well site during the fracturing phase of development, with maximum presence of on-site equipment. (New August 2011) ........................................................................................................ 7-125
Photo 7.2 - Sound Barrier. Source: Ground Water Protection Council, Oklahoma City, OK and ALL Consulting, Tulsa OK, 2009 (New August 2011) ........................................................................................................ 7-132
Photo 7.3 - Sound Barrier Installation (New August 2011) ................................................................................ 7-133
Photo 7.4 - Sound Barrier Installation (New August 2011) ................................................................................ 7-133
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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."\(^1\)

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\(^1\) 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. 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. 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

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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. In addition, effective December 8, 2008, the Compact 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;

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1 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)\textsuperscript{5}

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<tr>
<th>Agency</th>
<th>Potential Impacts of Reduced Stream Flow</th>
<th>Denigration of Stream’s Designated Best Use</th>
<th>Potential Impacts to Downstream Wetlands</th>
<th>Potential Impacts to Fish and Wildlife</th>
<th>Potential Aquifer Depletion</th>
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\textsuperscript{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.\textsuperscript{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.\textsuperscript{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.

\textsuperscript{7} 18 CFR Part 410.

\textsuperscript{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.”

**Impacts to Wetlands** - DRBC regulations concerning potential impacts to downstream wetlands are located in the Delaware River Basin Water Code 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. 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.

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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\textsuperscript{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.\textsuperscript{13} In general, the Commission promotes sound

\textsuperscript{12} 18CFR, Parts 801, 806, 807, and 808.

\textsuperscript{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.”\(^\text{1}^4\) 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.

\underline{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.\(^\text{1}^5\)

\underline{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, 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:

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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.\textsuperscript{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.\textsuperscript{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

\textsuperscript{20} Larsen, 1981.
\textsuperscript{21} IFC, 2004.
define and maintain the stream habitat suitable for aquatic biota. Research by Estes\textsuperscript{22} and Reiser et al.\textsuperscript{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\textsuperscript{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.”

\textsuperscript{22} Estes, 1984.
\textsuperscript{23} Reiser, et al., 1988.
\textsuperscript{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:

\[ Q_p = \left( \frac{A_p}{A_g} \right) \times Q_g \]

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.\textsuperscript{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).\textsuperscript{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.

\textsuperscript{25} DFWMR 2010.
\textsuperscript{26} DFWMR 2010.
\textsuperscript{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)

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

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. Watershed drainage areas can be determined using the USGS StreamStats tool accessible at [http://water.usgs.gov/osw/streamstats/ssonline.html](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 are 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 \( \Delta V \) = 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 (\( \Delta V \)) 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:

  o protect aquatic resources,

  o protect competing users,

  o protect instream flow uses,

  o 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 included 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;\(^\text{28}\) and
  - Draft Department Program Policy DER-17.\(^\text{29}\)
- 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


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.

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.”\(^ {33}\)

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\(^{33}\) 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.\textsuperscript{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.”\textsuperscript{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;

\textsuperscript{34} Freshwater Aquifer Supplementary Permit Conditions, www.dec.ny.gov/energy/42714.html.

\textsuperscript{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, 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:
  
  o Specification 5CT, Specifications for Casing and Tubing (April 2002);
  
  o Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);
  
  o RP 10D-2, RP for Centralizer Placement and Stop Collar Testing (August 2004);
  
  o Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum);
  
  o Guidance Document, HF1, Hydraulic Fracturing Operations - Well Construction and Integrity Guidelines (October 2009); and
  

• 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

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 2011 to reflect more recent recommendations from NYSDOH)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Barium</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Chloride</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Conductivity</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Gross alpha/beta</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Iron</strong></td>
<td>Iron is commonly found in many aquifers and may be mobilized during initial drilling activities.</td>
</tr>
<tr>
<td><strong>Manganese</strong></td>
<td>Manganese is commonly found in many deep and shallow aquifers and may be mobilized during initial drilling activities.</td>
</tr>
<tr>
<td><strong>Dissolved methane &amp; ethane</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>pH</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Sodium</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Total dissolved solids (TDS)</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Static water level</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Volatile organic compounds (VOCs), specifically BTEX</strong></td>
<td>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.</td>
</tr>
</tbody>
</table>
**Sampling Protocol**

The Department proposes to require that water samples be collected by a qualified professional and analyzed utilizing a NYSDOH ELAP approved laboratory, 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.

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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. Subsection 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. 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. 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:

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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;

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
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. 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

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,

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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), 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.

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

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45 Lash and Engelder, 2008.
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. 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. 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:

The 1992 GEIS and its Findings;

NYSDOH’s required water well separation distances, set forth in Appendix 5-B of the State Sanitary Code.\footnote{http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.} 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;\footnote{Alpha, 2009, Tables 2.1 - 2.10.}

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.\footnote{Alpha, 2009, p. 94.} 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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\footnote{http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.}

\footnote{Alpha, 2009, Tables 2.1 - 2.10.}

\footnote{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](http://oaspub.epa.gov/enviro/sdw_form_v2.create_page?state_abbr=NY); and
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 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.

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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/. 

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Revised Draft SGEIS 2011, Page 7-72
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. 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

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54 [http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1](http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1), viewed 8/26/09.
wells. 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.

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.” 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;

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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.

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\(^{58}\) Alpha, 2009, pp. 41-45.

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;\textsuperscript{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;\textsuperscript{61}

\textsuperscript{60} Environmental Law Clinic 2010.
\textsuperscript{61} New Mexico Dept Game & Fish, 2007.
• Design roads to lessen impacts (including two-track roads and oak mats in low-volume areas\textsuperscript{62}) and limit canopy gaps\textsuperscript{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\textsuperscript{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.

\textsuperscript{62} Weller et al., 2002.

\textsuperscript{63} NYSDEC, Strategic Plan for State Forest Management, 2010.

\textsuperscript{64} New Mexico Dept Game & Fish, 2007.
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. The focus areas were derived from Breeding Bird Atlas (BBA) data from 2002-2004; 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

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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)

<table>
<thead>
<tr>
<th>Grassland Focus Area</th>
<th>Species</th>
</tr>
</thead>
<tbody>
<tr>
<td>Western Area</td>
<td>Upland sandpiper, vesper sparrow, horned leak, savannah sparrow, short-eared owl*</td>
</tr>
<tr>
<td>Southern Area</td>
<td>Northern Harrier, grasshopper sparrow, Eastern meadowlark, savannah sparrow</td>
</tr>
<tr>
<td>Middle Northern Area</td>
<td>Vesper sparrow, grasshopper sparrow, horned lark, savannah sparrow, short-eared owl*</td>
</tr>
<tr>
<td>Eastern Area</td>
<td>Northern harrier, short-eared owl*</td>
</tr>
</tbody>
</table>

*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.\(^{68}\)


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). 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.

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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).²⁰

Figure 7.3 - Scaling Factors for Matrix Forest Systems in the High Allegheny Ecoregion¹ (New July 2011)

Scaling factors for Matrix Forest Systems in the High Allegheny ecoregion.

<table>
<thead>
<tr>
<th>DISTURBANCES</th>
<th>Poor</th>
<th>Fair</th>
<th>Good</th>
<th>Very Good</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fires (N Hardwood)</td>
<td>Diseases</td>
<td>Tornadoes</td>
<td>Ecosystem viability threshold</td>
<td></td>
</tr>
<tr>
<td>Hurricanes</td>
<td>Fires (Oak-Pine)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SPECIES</th>
<th>Poor</th>
<th>Fair</th>
<th>Good</th>
<th>Very Good</th>
</tr>
</thead>
<tbody>
<tr>
<td>Filated Woodpecker</td>
<td>Barred Owl</td>
<td>Cooper's Hawk</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carolina W</td>
<td>Broad-winged Hawk</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Black &amp; White W</td>
<td>All Neotropical birds *</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wryneck</td>
<td>Bobcat</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

0 2 5 10 15 20 25 30 35 40 // 75 // 150

Reserve size in 1000s of acres

Factors to the left of the arrow should be encompassed by a 15,000 acre reserve.

*Neotropical species richness point based on Robbins et al. 1989, and Adams, see text for full explanation.

¹ TNC, 2003.
²¹ 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.\textsuperscript{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

\textsuperscript{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. 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. 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.

- 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:

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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.\textsuperscript{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\textsuperscript{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.\textsuperscript{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

\textsuperscript{76} New Mexico Dept Game & Fish, 2007.
\textsuperscript{77} New Mexico Dept Game & Fish, 2007.
\textsuperscript{78} ECL § 9-1707.
\textsuperscript{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.
\textsuperscript{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 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.
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. 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 to 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

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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

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

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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**

<table>
<thead>
<tr>
<th>Agency</th>
<th>Document</th>
<th>Article</th>
<th>Regulation Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>SRBC</td>
<td>Federal Register, Vol 73, No. 247, Rules and Regulations</td>
<td>18 CFR Part 806.22,1,8</td>
<td>All flowback and produced fluids, including brines, must be treated and disposed of in accordance with applicable state and federal law.</td>
</tr>
<tr>
<td>SRBC</td>
<td>Regulation of Projects</td>
<td>18 CFR Parts 806.20,4,1</td>
<td>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 SRB 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.</td>
</tr>
<tr>
<td>SRBC</td>
<td>Regulation of Projects</td>
<td>18 CFR Part 801.3.b</td>
<td>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.</td>
</tr>
<tr>
<td>SRBC</td>
<td>Regulation of Projects</td>
<td>18 CFR Part 801.3.c,1</td>
<td>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.</td>
</tr>
<tr>
<td>SRBC</td>
<td>Regulation of Projects</td>
<td>18 CFR Part 806.23,2</td>
<td>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.</td>
</tr>
<tr>
<td>SRBC</td>
<td>Federal Register, Vol 73, No. 247, Rules and Regulations</td>
<td>18 CFR Part 806.22,1,6</td>
<td>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].</td>
</tr>
<tr>
<td>DRBC</td>
<td>Water Code 18 CFR Part 410</td>
<td>2.20.2</td>
<td>The underground water-bearing formations of the DRB, their waters, storage capacity, recharge areas, and ability to convey water shall be preserved and protected.</td>
</tr>
<tr>
<td>DRBC</td>
<td>Water Code 18 CFR Part 410</td>
<td>2.20.3</td>
<td>Projects that withdraw underground waters must reasonably safeguard the present and future public interest in the affected water resources.</td>
</tr>
<tr>
<td>DRBC</td>
<td>Water Code 18 CFR Part 410</td>
<td>2.20.4</td>
<td>Withdrawals from DRB ground waters 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 &quot;long term progressive lowering of ground water levels.&quot;</td>
</tr>
<tr>
<td>DRBC</td>
<td>Water Code 18 CFR Part 410</td>
<td>2.20.5</td>
<td>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.</td>
</tr>
<tr>
<td>DRBC</td>
<td>Water Code 18 CFR Part 410</td>
<td>2.20.6</td>
<td>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.</td>
</tr>
<tr>
<td>DRBC</td>
<td>Water Code 18 CFR Part 410</td>
<td>2.10.1</td>
<td>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.</td>
</tr>
</tbody>
</table>

*Revised Draft SGEIS 2011, Page 5-94*
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.

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 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.

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.

DRB water quality will be maintained in a safe and satisfactory condition for...wildlife, fish and other aquatic life.

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.

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.

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 result 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.

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 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: a) the public interest warrants these changes, unless such change is justifiable as a result 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. 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 any)

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 wastewater 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.

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...
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

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.

All wastes shall receive a minimum of secondary treatment, regardless of the stated stream quality objective. 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.

Effluents shall not create a menace to public health or safety at the point of discharge.

Lists discharge contaminant limits.

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.

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.

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.

(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 140°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 Chapter 2, 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$_2$, 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\textsubscript{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\textsubscript{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\textsubscript{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\textsubscript{x}. In NSCR, hydrocarbons and CO are oxidized by O\textsubscript{2} and NO\textsubscript{x}. The excess hydrocarbons, CO and NO\textsubscript{x} pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H\textsubscript{2}O and CO\textsubscript{2}, while reducing NO\textsubscript{x} to N\textsubscript{2}. NO\textsubscript{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 NOx 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 NOx. 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 NOx 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 NOx 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. NOx, NH3, and O2 react on the surface of the catalyst to form N2 and H2O. 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 (850° F) will pass the NOx and ammonia unreacted through the catalyst. Ammonia emissions, called NH3 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 NOx control placed in the exhaust stream following the engine and involves injecting ammonia (NH₃) into the flue gas. The NH₃ reacts with NOx 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 NOx 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 NOx, CO, and HC and the system involves placing a catalyst in the exhaust stream of the engine. The reaction requires that the O₂ 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 - SOx

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 SO₂. The oxidation of SO₂ creates sulfur trioxide (SO₃), which reacts with water to create sulfuric acid (H₂SO₄), 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:

$$LOPT = 1.15 \times 3.0 \text{ gal TEG} \times \frac{F \times (I - O)}{\text{lb } H_2O \{24\text{hr/day}\}}$$

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$_2$O 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 H₂S;

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\textsubscript{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

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Pollutant</th>
<th>Stack Height</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flowback vent</td>
<td>H₂S</td>
<td>30 feet NOTE: not required if previous drilling at the same pad has demonstrated that H₂S is not present</td>
</tr>
<tr>
<td>Glycol dehydrator</td>
<td>Benzene</td>
<td>30 feet NOTE: Subpart HH compliance as described in Section 7.5.1.3 is also required.</td>
</tr>
</tbody>
</table>
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 (CO₂) and methane (CH₄) as both short tons and as carbon dioxide equivalents (CO₂e) 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 CO₂ and CH₄ 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 CH₄ 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 CH₄, 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)\(^8\)

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

\(^8\) [http://www.epa.gov/gasstar/join/index.html](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 \( \text{CH}_4 \);
• 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 CH₄. Natural gas compressors which run virtually around-the-clock, produce both CO₂ and CH₄ emissions. Equipment required to process produced natural gas, specifically the glycol dehydrators (i.e., vents & pumps) and pneumatic devices, generate CH₄ 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;²⁶

• Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry;²⁷

• 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

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 waste 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

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

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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

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

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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 sitting 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.
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. 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

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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

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

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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:
  
  o orienting high-pressure discharge pipes away from noise receptors;

  o having the air connection blowdown manifolded into the flow line. This would provide the air with a larger-diameter aperture at the discharge point;

  o 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;

  o shrouding the discharge point by sliding open-ended pieces of larger-diameter pipe over them; or

  o 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

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.

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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

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

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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.
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

CHAPTER 8 PERMIT PROCESS AND REGULATORY COORDINATION ................................................................. 8-1

8.1 INTERAGENCY COORDINATION ..................................................................................................................... 8-1
8.1.1 Local Governments ....................................................................................................................................... 8-1
  8.1.1.1 SEQRA Participation .............................................................................................................................. 8-1
  8.1.1.2 NYCDEP ............................................................................................................................................. 8-4
  8.1.1.3 Local Government Notification ......................................................................................................... 8-4
  8.1.1.4 Road-Use Agreements ......................................................................................................................... 8-4
  8.1.1.5 Local Planning Documents .................................................................................................................. 8-4
  8.1.1.6 County Health Departments.................................................................................................................. 8-5
8.1.2 State ............................................................................................................................................................ 8-5
  8.1.2.1 Public Service Commission ................................................................................................................. 8-6
  8.1.2.2 NYS Department of Transportation .................................................................................................... 8-18
8.1.3 Federal ......................................................................................................................................................... 8-19
  8.1.3.1 U.S. Department of Transportation ................................................................................................. 8-19
  8.1.3.2 Occupational Safety and Health Administration – Material Safety Data Sheets ............................. 8-21
  8.1.3.3 EPA’s Mandatory Reporting of Greenhouse Gases ............................................................................. 8-24
8.1.4 River Basin Commissions .......................................................................................................................... 8-28

8.2 INTRA-DEPARTMENT ...................................................................................................................................... 8-29
8.2.1 Well Permit Review Process ...................................................................................................................... 8-29
  8.2.1.1 Required Hydraulic Fracturing Additive Information ........................................................................ 8-29
8.2.2 Other Department Permits and Approvals ............................................................................................... 8-32
  8.2.2.1 Bulk Storage .................................................................................................................................... 8-32
  8.2.2.2 Impoundment Regulation .................................................................................................................. 8-33
8.2.3 Enforcement .............................................................................................................................................. 8-42
  8.2.3.1 Enforcement of Article 23 .................................................................................................................. 8-42
  8.2.3.2 Enforcement of Article 17 .................................................................................................................. 8-44

8.3 WELL PERMIT ISSUANCE ............................................................................................................................... 8-48
8.3.1 Use and Summary of Supplementary Permit Conditions for High-Volume Hydraulic Fracturing .......... 8-48
8.3.2 High-Volume Re-Fracturing ...................................................................................................................... 8-48

8.4 OTHER STATES’ REGULATIONS .................................................................................................................... 8-49
8.4.1 Ground Water Protection Council ........................................................................................................... 8-51
  8.4.1.1 GWPC - Hydraulic Fracturing ............................................................................................................. 8-51
  8.4.1.2 GWPC - Other Activities .................................................................................................................... 8-52
8.4.2 Alpha’s Regulatory Survey ....................................................................................................................... 8-53
  8.4.2.1 Alpha - Hydraulic Fracturing .............................................................................................................. 8-53
  8.4.2.2 Alpha - Other Activities ..................................................................................................................... 8-54
8.4.3 Colorado’s Final Amended Rules ............................................................................................................ 8-61
  8.4.3.1 Colorado - New MSDS Maintenance and Chemical Inventory Rule ................................................. 8-61
  8.4.3.2 Colorado - Setbacks from Public Water Supplies .......................................................................... 8-62
8.4.4 Summary of Pennsylvania Environmental Quality Board. Title 25-Environmental Protection, Chapter 78, Oil and Gas Wells ................................................................. 8-63
8.4.5 Other States’ Regulations - Conclusion .................................................................................................. 8-63

FIGURES
Figure 8.1- Protection of Waters - Dam Safety Permitting Criteria .................................................................... 8-35

TABLES
Table 8.1 - Regulatory Jurisdictions Associated with High-Volume Hydraulic Fracturing (Revised July 2011) ........ 8-3
Table 8.2 - Intrastate Pipeline Regulation ......................................................................................................... 8-10
Table 8.3 - Water Resources and Private Dwelling Setbacks from Alpha, 2009 .................................................. 8-60

Revised Draft SGEIS 2011, Page 8-i
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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)

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<td>Hydraulic fracturing/</td>
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<td>-</td>
<td>*</td>
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<tr>
<td>refracturing</td>
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<tr>
<td>Cuttings and reserve pit</td>
<td>P</td>
<td>-</td>
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<td>A</td>
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<td>liner disposal</td>
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<td>Site restoration</td>
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<td>Production operations</td>
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<tr>
<td>Gathering lines and</td>
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<td>compressor stations</td>
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<td>Air emissions from all site</td>
<td>S</td>
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<td>operations</td>
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<td>Well plugging</td>
<td>P</td>
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<tr>
<td>Invasive species control</td>
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</tbody>
</table>

**Fluid Disposal Plan**

6NYCRR 554.1(c)(1)

| Waste transport             | -   | -   | P   | -   | -   | -     | -   | -   | -   | -   | -     | -   | *    | -    | -            | -            |     |     |     |
| POTW disposal               | -   | *   | P   | -   | -   | -     | -   | -   | -   | -   | -     | -   | -    | *    | -            | -            |     |     |     |
| New in-state industrial     | -   | P   | S   | -   | -   | -     | -   | -   | -   | -   | -     | -   | -    | A*   | -            | -            |     |     |     |
| treatment plants            |     |     |     |     |     |       |     |     |     |     |       |     |       |      |               |              |     |     |     |
| Injection well disposal     | S   | P   | S   | -   | -   | -     | -   | -   | -   | P   | -     | -   | -    | -    | -            | -            |     |     |     |
| Road spreading              | -   | -   | -   | 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
EPA = Environmental Protection Agency
USDOT = United States Department of Transportation
Corps = US Army Corps of Engineers
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.”

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; 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,” 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.

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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.

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

<table>
<thead>
<tr>
<th>Pipeline Type</th>
<th>Department</th>
<th>PSC</th>
</tr>
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<tbody>
<tr>
<td>Gathering &lt;125 psig</td>
<td>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).</td>
<td>Safety jurisdiction. Public Service Law § 66, 16 NYCRR § 255.9 and Appendix 7-G(a)**.</td>
</tr>
<tr>
<td>Gathering ≥125 psig, &lt;1,000 ft.</td>
<td>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).</td>
<td>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.</td>
</tr>
<tr>
<td>Fuel Gas Transmission*</td>
<td>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).</td>
<td>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)<strong>. 16 NYCRR Subpart 85-1. EM&amp;CS&amp;P</strong>* checklist must be filed. Service of NOI or application to other agencies required.</td>
</tr>
<tr>
<td>Fuel Gas Transmission*</td>
<td>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).</td>
<td>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)<strong>. 16 NYCRR Subpart 85-1. EM&amp;CS&amp;P</strong>* checklist must be filed. Service of NOI or application to other agencies required.</td>
</tr>
<tr>
<td>Fuel Gas Transmission*</td>
<td>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).</td>
<td>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.</td>
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</table>

* 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.

4 Adapted from the NYSDEC GEIS 1992.
Application

An Article VII application must contain the following information:

- location of the line and right-of-way;
- description of the transmission facility being proposed;
- summary of any studies made of the environmental impact of the facility, and a description of such studies;
- statement explaining the need for the facility;
- description of any reasonable alternate route(s), including a description of the merits and detriments of each route submitted, and the reasons why the primary proposed route is best suited for the facility; and
- such information as the applicant may consider relevant or the Commission may require.

In an application, the applicant is also encouraged to detail its public involvement activities and its plans to encourage public participation. DPS staff takes about 30 days after an application is filed to determine if the application is in compliance with Article VII filing requirements. If an application lacks required information, the applicant is informed of the deficiencies. The applicant can then file supplemental information. If the applicant chooses to file the supplemental information, the application is again reviewed by the DPS for a compliance determination. Once an application for a Certificate is filed with the PSC, no local municipality or other State agency may require any hearings or permits concerning the proposed facility.

Timing of Application & Pipeline Construction

The extraction of projected economically recoverable reserves from the Marcellus Shale, and other low-permeability gas reservoirs, presents a unique challenge and opportunity with respect to the timing of an application and ultimate construction of the pipeline facilities necessary to tie this gas source into the transportation system and bring the produced gas to market. In the course of developing other gas formations, the typical sequence of events begins with the operator first drilling a well to determine its productivity and, if successful, then submitting an Article VII application for PSC approval to construct the associated pipeline. This reflects the risk associated with conventional oil and gas exploration where finding natural gas in paying quantities is not guaranteed and the same appears to be true for potential drilling under the SGEIS as not all wells drilled will be productive. More than one or two wells on the same pad
may need to be drilled to prove economical production prior to an operator making a
commitment to invest in and build a pipeline. Actual drilling at any given location is the only
way to know if a given area will be productive, especially in the fringe of any predetermined
productive fairways. In 2010, it was reported that Encana Oil & Gas USA Inc. drilled several
unsuccessful Marcellus Shale wells in Luzerne County, Pennsylvania and that “there wasn’t
enough gas in either to be marketable.”

Consequently, the typical procedure of drilling wells, testing wells by flaring and then
constructing gathering lines may or may not be suited for the development of the Marcellus
Shale and other low permeability reservoirs depending upon the location of proposed wells and
the establishment of productive fairways through drilling experience. In 2009, the success rate
of horizontally drilled and hydraulically fractured Marcellus Shale wells in neighboring
Pennsylvania and West Virginia, as reported by three companies, was one hundred percent for 44
wells drilled. This early rate of success was apparently due primarily to the fact that the
Marcellus Shale reservoir in location-specific fairways appears to contain natural gas in
sufficient quantities which can be produced economically using horizontal drilling and high-
volume hydraulic fracturing technology. However, as noted above, some Marcellus Shale wells
subsequently drilled in Pennsylvania apparently using the same technology did not prove
successful. It is highly unlikely that an operator in New York would make a substantial
investment in a pipeline ahead of completing a well unless drilling is conducted in a known
productive fairway and there is a near guarantee of finding gas in suitable quantities and at viable
flow rates.

In addition, the Marcellus Shale formation in some areas is known to have a high concentration
of clay that is sensitive to fresh water contact which makes the formation susceptible to re-
closing if the flowback fluid and natural gas do not flow immediately after hydraulic fracturing
operations. The horizontal drilling and hydraulic fracturing technique used to tap into the
Marcellus in these areas could require that the well be flowed back and gas produced

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immediately after the well has been fractured and completed, otherwise the formation may be damaged and the well may cease to be economically productive. However, clay stabilizer additives are available for injection during hydraulic fracturing operations which help inhibit the swelling of clays present in the target formation. In addition to possibly enhancing the completion by preventing formation damage, having a pipeline in place when a well is initially flowed would reduce the amount of gas flared to the atmosphere during initial recovery operations. This type of completion with limited or no flaring is referred to as a reduced emissions completion (REC). To combat formation damage during hydraulic fracturing with conventional fluids, a new and alternative hydraulic fracturing technology recently entered the Canadian market and has also been used in Pennsylvania on a limited basis. It uses liquefied petroleum gas (LPG), consisting mostly of propane in place of water-based hydraulic fracturing fluids. Using propane not only minimizes formation damage, but also eliminates the need to source water for hydraulic fracturing, recover flowback fluids to the surface and dispose of the flowback fluids. While it is not known if or when LPG hydraulic fracturing will be proposed in New York, having gathering infrastructure in place may be an important factor in realizing the advantages of this technology. Instead of LPG/natural gas separation equipment being required at individual well pads during flowback, an in-place gas production pipeline would allow and facilitate the siting of centralized separation equipment that could service a number of well pads thereby providing for a more efficient LPG hydraulic fracturing operation.

Also, if installed prior to well drilling, an in-place gas production pipeline could serve a second purpose and be used initially to transport fresh water or recycled hydraulic fracturing fluids to the well site for use in hydraulic fracturing the first well on the pad. This in itself would reduce or eliminate other fluid transportation options, such as trucking and construction of a separate fluid pipeline, and associated impacts. Because of the many potential benefits noted above, which have been demonstrated in other states, it has been suggested that New York should have the option, after drilling experience is gained, to certify and build pipelines in advance of well drilling targeting the Marcellus Shale and other low-permeability gas reservoirs in known productive fairways.

Filing and Notice Requirements

Article VII requires that a copy of an application for a transmission line ten miles or longer in length be provided by the applicant to the Department, the Department of Economic Development, the Secretary of State, the Department of Agriculture and Markets and the Office of Parks, Recreation and Historic Preservation, and each municipality in which any portion of the facility is proposed to be located. This is done for both the primary route proposed and any alternative locations listed. A copy of the application must also be provided to the State legislators whose districts the proposed primary facility or any alternative locations listed would pass through. Service requirements for transmission lines less than 10 miles in length are slightly different but nevertheless comprehensive.

An Article VII application for a transmission line ten miles or longer in length must be accompanied by proof that notice was published in a newspaper(s) of general circulation in all areas through which the facility is proposed to pass, for both its primary and alternate routes. The notice must contain a brief description of the proposed facility and its proposed location, along with a discussion of reasonable alternative locations. An applicant is not required to provide copies of the application or notice of the filing of the application to individual property owners of land on which a portion of either the primary or alternative route is proposed. However, to help foster public involvement, an applicant is encouraged to do so.

Party Status in the Certification Proceeding

Article VII specifies that the applicant and certain State and municipal agencies are parties in any case. The Department and the Department of Agriculture & Markets are among the statutorily named parties and usually actively participate. Any municipality through which a portion of the proposed facility will pass, or any resident of such municipality, may also become a formal party to the proceeding. Obtaining party status enables a person or group to submit testimony, cross-examine witnesses of other parties and file briefs in the case. Being a party also entails the responsibility to send copies of all materials filed in the case to all other parties. DPS staff participates in all Article VII cases as a party, in the same way as any other person who takes an active part in the proceedings.
The Certification Process

Once all of the information needed to complete an application is submitted and the application is determined to be in compliance, review of the application begins. In a case where a hearing is held, the Commission’s Office of Hearings and Alternative Dispute Resolution provides an Administrative Law Judge (ALJ) to preside in the case. The ALJ is independent of DPS staff and other parties and conducts public statement and evidentiary hearings and rules on procedural matters. Hearings help the Commission decide whether the construction and operation of new transmission facilities will fulfill the public need, be compatible with environmental values and the public health and safety, and comply with legal requirements. After considering all the evidence presented in a case, the ALJ usually makes a recommendation for the Commission’s consideration.

Commission Decision

The Commission reviews the ALJ’s recommendation, if there is one, and considers the views of the applicant, DPS staff, other governmental agencies, organizations, and the general public, received in writing, orally at hearings or at any time in the case. To grant a Certificate, either as proposed or modified, the Commission must determine all of the following:

- the need for the facility;
- the nature of the probable environmental impact;
- the extent to which the facility minimizes adverse environmental impact, given environmental and other pertinent considerations;
- that the facility location will not pose undue hazard to persons or property along the line;
- that the location conforms with applicable State and local laws; and
- that the construction and operation of the facility is in the public interest.

Following Article VII certification, the Commission typically requires the certificate holder to submit various additional documents to verify its compliance with the certification order. One of the more notable compliance documents, an Environmental Management and Construction Plan (EM&CP), must be approved by the Commission before construction can begin. The EM&CP details the precise field location of the facilities and the special precautions that will be taken.
during construction to ensure environmental compatibility. The EM&CP must also indicate the practices to be followed to ensure that the facility is constructed in compliance with applicable safety codes and the measures to be employed in maintaining and operating the facility once it is constructed. Once the Commission is satisfied that the detailed plans are consistent with its decision and are appropriate to the circumstances, it will authorize commencement of construction. DPS staff is then responsible for checking the applicant’s practices in the field.

**Amended Certification Process**

In 1981, the Legislature amended Article VII to streamline procedures and application requirements for the certification of fuel gas transmission facilities operating at 125 psig or more, and that extend at least 1,000 feet, but less than ten miles. The pipelines or gathering lines associated with wells being considered in this document typically fall into this category, and, consequently, a relatively expedited certification process occurs that is intended to be no less protective. The updated requirements mimic those described above with notable differences being: 1) a NOI may be filed instead of an application, 2) there is no mandatory hearing with testimony or required notice in newspaper, and 3) the PSC is required to act within thirty or sixty days depending upon the size and length of the pipeline.

The updated requirements applicable to such fuel gas transmission facilities are set forth in PSL Section 121-a and 16 NYCRR Sub-part 85-1. All proposed pipeline locations are verified and walked in the field by DPS staff as part of the review process, and staff from the Department and Department of Agriculture & Markets may participate in field visits as necessary. As mentioned above, these departments normally become active parties in the NOI or application review process and usually provide comments to DPS staff for consideration. Typical comments from the Department and Agriculture and Markets relate to the protection of agricultural lands, streams, wetlands, rare or state-listed animals and plants, and significant natural communities and habitats.

Instead of an applicant preparing its own environmental management and construction standards and practices (EM&CS&P), it may choose to rely on a PSC-approved set of standards and practices, the most comprehensive of which was prepared by DPS staff in February 2006.\(^8\) The

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\(^8\) NYSDPS. 2006.
DPS—authored EM&CS&P was written primarily to address construction of smaller-scale fuel gas transmission projects envisioned by PSL Section 121-a that will be used to transport gas from the wells being considered in this document. Comprehensive planning and construction management are key to minimizing adverse environmental impacts of pipelines and their construction. The EM&CS&P is a tool for minimizing such impacts of fuel gas transmission pipelines reviewed under the PSL. The standards and practices contained in the 2006 EM&CS&P handbook are intended to cover the range of construction conditions typically encountered in constructing pipelines in New York.

The pre-approved nature of the 2006 EM&CS&P supports a more efficient submittal and review process, and aids with the processing of an application or NOI within mandated time frames. The measures from the EM&CS&P that will be used in a particular project must be identified on a checklist and included in the NOI or application. A sample checklist is included as Appendix 14, which details the extensive list of standards and practices considered in DPS’s EM&CS&P and readily available to the applicant. Additionally, the applicant must indicate and include any measures or techniques it intends to modify or substitute for those included in the PSC-approved EM&CS&P.

An important measure specified in the EM&CS&P checklist is a requirement for supervision and inspection during various phases of the project. Page four of the 2006 EM&CS&P states “At least one Environmental Inspector (EI) is required for each construction spread during construction and restoration. The number and experience of EIs should be appropriate for the length of the construction spread and number/significance or resources affected.” The 2006 EM&CS&P also requires that the name(s) of qualified Environmental Inspector(s) and a statement(s) of the individual’s relative project experience be provided to the DPS prior to the start of construction for DPS staff’s review and acceptance. Another important aspect of the PSC-approved EM&CS&P is that Environmental Inspectors have stop-work authority entitling the EI to stop activities that violate Certificate conditions or other federal, State, local or landowner requirements, and to order appropriate corrective action.
Conclusion

Whether an applicant submits an Article VII application or Notice of Intent as allowed by the Public Service Law, the end result is that all Public Service Commission-issued Certificates of Environmental Compatibility and Public Need for fuel gas transmission lines contain ordering clauses, stipulations and other conditions that the Certificate holder must comply with as a condition of acceptance of the Certificate. Many of the Certificate’s terms and conditions relate to environmental protection. The Certificate holder is fully expected to comply with all of the terms and conditions or it may face an enforcement action. DPS staff monitor construction activities to help ensure compliance with the Commission’s orders. After installation and pressure testing of a pipeline, its operation, monitoring, maintenance and eventual abandonment must also be conducted in accordance with and adhere to the provisions of the Certificate and New York State law and regulations.

8.1.2.2 NYS Department of Transportation

New York State requires all registrants of commercial motor vehicles to obtain a USDOT number. New York has adopted the FMCSA regulations CFR 49, Parts 390, 391, 392, 393, 395, and 396, and the Hazardous Materials Transportation Regulations, Parts 100 through 199, as those regulations apply to interstate highway transportation (NYSDOT, 6/2/09). There are minor exemptions to these federal regulations in NYCRR Title17 Part 820, “New York State Motor Carrier Safety Regulations”; however, the exemptions do not directly relate to the objectives of this review.

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

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

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

NYSDOT would also have an advisory role with respect to the transportation plans and road condition assessments that operators will be required to submit.

8.1.3 Federal

The United States Department of Transportation is the only newly listed federal agency in Table 8.1. As explained in Chapter 5, the US DOT regulates transportation of hazardous chemicals found in fracturing additives and has also established standards for containers. Roles of the other federal agencies shown on Table 15.1 will not change.

8.1.3.1 U.S. Department of Transportation

The federal Hazardous Material Transportation Act (HMTA, 1975) and the Hazardous Materials Transportation Uniform Safety Act (HMTUSA, 1990) are the basis for federal hazardous materials transportation law (49 U.S.C.) and give regulatory authority to the Secretary of the USDOT to:
“Designate material (including an explosive, radioactive, infectious substance, flammable or combustible liquid, solid or gas, toxic, oxidizing, or corrosive material, and compressed gas) or a group or class of material as hazardous when the Secretary determines that transporting the material in commerce in a particular amount and form may pose an unreasonable risk to health and safety or property; and

“Issue regulations for the safe transportation, including security, of hazardous material in intrastate, interstate, and foreign commerce” (PHMSA, 2009).

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

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

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

Regulatory functions are carried out by the following USDOT agencies:

- Pipeline and Hazardous Materials Safety Administration (PHMSA);
- Federal Motor Carrier Safety Administration (FMCSA);
- Federal Aviation Administration (FAA); and
- United States Coast Guard (USCG).
Each of these agencies shares in promulgating regulations and enforcing the federal hazmat regulations. State, local, or tribal requirements may only preempt federal hazmat regulations if one of the federal enforcing agencies issues a waiver of preemption based on accepting a regulation that offers an equal or greater level of protection to the public and does not unreasonably burden commerce.

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

8.1.3.2 Occupational Safety and Health Administration – Material Safety Data Sheets

The Occupational Safety and Health Administration (OSHA) is part of the United States Department of Labor, and was created by Congress under the Occupational Safety and Health Act of 1970 to ensure safe and healthful working conditions by setting and enforcing standards and by providing training, outreach, education and assistance.\(^9\)

In order to ensure chemical safety in the workplace, information must be available about the identities and hazards of chemicals. OSHA’s Hazard Communication Standard, 29 CFR §1910.1200,\(^10\) requires the development and dissemination of such information and requires that chemical manufacturers and importers evaluate the hazards of the chemicals they produce or import, prepare labels and Material Safety Data Sheets (MSDSs) to convey the hazard.

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\(^9\) OSHA. http://www.osha.gov/about.html.

information, and train workers to handle chemicals appropriately. This standard also requires all employers to have MSDSs in their workplaces for each hazardous chemical they use.

The requirements pertaining to MSDSs are described in 29 CFR §1910.1200(g), and include the following information:

- The identity used on the label;
- The chemical\textsuperscript{11} and common name(s)\textsuperscript{12} of the hazardous chemical\textsuperscript{13} ingredients, except as provided for in §1910.1200(i) regarding trade secrets;
- Physical and chemical characteristics of the hazardous chemical(s);
- Physical hazards of the hazardous chemical(s), including the potential for fire, explosion and reactivity;
- Health hazards of the hazardous chemical(s);
- Primary route(s) of entry;
- The OSHA permissible exposure limit, ACGIH Threshold Limit Value, and any other exposure limit used or recommended by the chemical manufacturer, importer or employer preparing the MSDS;
- Whether the hazardous chemical(s) is listed in the National Toxicology Program (NTP) Annual Report on Carcinogens (latest edition) or has been found to be a potential carcinogen in the International Agency for Research on Cancer (IARC) Monographs (latest editions), or by OSHA;

\textsuperscript{11} 29 CFR §1910.1200(c) defines “chemical name” as “the scientific designation of a chemical in accordance with the nomenclature system developed by the International Union or Pure and Applied Chemistry (IUPAC) or the Chemical Abstracts Service (CAS) rules of nomenclature, or a name which will clearly identify the chemical for the purpose of conducting a hazard evaluation.”

\textsuperscript{12} 29 CFR §1910.1200(c) defines “common name” as “any designation or identification such as code name, code number, trade name, brand name or generic name used to identify a chemical other than by its chemical name.”

\textsuperscript{13} 29 CFR §1910.1200(c) defines “hazardous chemical” as “any chemical which is a physical hazard or a health hazard,” and further defines “physical hazard” and “health hazard” respectively as follows: “Physical hazard means a chemical for which there is scientifically valid evidence that it is a combustible liquid, a compressed gas, explosive, flammable, an organic peroxide, an oxidizer, pyrophoric, unstable (reactive) or water-reactive”; “Health hazard means a chemical for which there is statistically significant evidence based on at least one study conducted in accordance with established scientific principles that acute or chronic health effects may occur in exposed employees. The term ‘health hazard’ includes chemicals which are carcinogens, toxic or highly toxic agents, reproductive toxins, irritants, corrosives, sensitizers, hepatotoxins, nephrotoxins, neurotoxins, agents which act on the hematopoietic system, and agents which damage the lungs, skin, eyes, or mucous membranes.”
• Any generally applicable precautions for safe handling and use including appropriate hygienic practices, measures during repair and maintenance of contaminated equipment, and procedures for clean-up of spills and leaks;

• Any generally applicable control measures such as appropriate engineering controls, work practices, or personal protective equipment;

• Emergency and first aid procedures;

• Date of preparation of the MSDS or the last change to it; and

• Name, address and telephone number of the chemical manufacturer, importer, employer or other responsible party preparing or distributing the MSDS, who can provide additional information on the hazardous chemical and appropriate emergency procedures, if necessary.

**MSDSs and Trade Secrets**

29 CFR §1910.1200(i) sets forth an exception from disclosure in the MSDS of the specific chemical identity, including the chemical name and other specific identification of a hazardous chemical, if such information is considered to be trade secret. This exception however is conditioned on the following:

• that the claim of trade secrecy can be supported;

• that the MSDS discloses information regarding the properties and effects of the hazardous chemical;

• that the MSDS indicates the specific chemical identity is being withheld as a trade secret; and

• that the specific chemical identity is made available to health professionals, employees, and designated representatives in accordance with the provisions of 29 CFR §1910.1200(i)(3) and (4) which discuss emergency and non-emergency situations.
8.1.3.3 EPA’s Mandatory Reporting of Greenhouse Gases

In October 2009, the United States EPA published 40 CFR §98, referred to as the Greenhouse Gas (GHG) Reporting Program, which mandates the monitoring and reporting of GHG emissions from certain source categories in the United States. The nationwide emission data collected under the program will provide a better understanding of the relative GHG emissions of specific industries and of individual facilities within those industries, as well as better understanding of the factors that influence GHG emissions rates and actions facilities could take to reduce emissions.¹⁴

The GHG reporting requirements for facilities that contain petroleum and natural gas systems were finalized in November 2010 as Subpart W of 40 CFR §98. Under Subpart W, facilities that emit 25,000 metric tons or more of CO₂ equivalent¹⁵ per year in aggregated emissions from all sources are required to report annual GHG emission to EPA. More specifically, petroleum and natural gas facilities that meet or exceed the reporting threshold are required to report annual methane (CH₄) and carbon dioxide (CO₂) emissions from equipment leaks and venting, and emissions of CO₂, CH₄, and nitrous oxide (N₂O) from flaring, onshore production stationary and portable combustion emission, and combustion emissions from stationary equipment involved in natural gas distribution.¹⁶

The rule requires data collection to begin on January 1, 2011 and that reports be submitted annually by March 31ˢᵗ, for the GHG emissions from the previous calendar year.

**Onshore Petroleum and Natural Gas Production Sector**

For monitoring and reporting purposes, Subpart W divides the petroleum and natural gas systems source category into seven segments including: onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (LNG)

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¹⁴ USEPA, August 2010.

¹⁵ CO₂ equivalent is defined by EPA as a metric measure used to compare the emissions from various GHGs based upon their global warming potential (GWP), which is the cumulative radiative forcing effects of a gas over a specified time horizon resulting from the emission of a unit mass of gas relative to a reference gas.

¹⁶ USEPA, Fact Sheet for Subpart W, November 2010.
storage and LNG import and export, and natural gas distribution. 40 CFR §98.230(a)(2) defines onshore petroleum and natural gas production to mean:

“all equipment on a well pad or associated with a well pad (including compressors, generators, or storage facilities), and portable non-self-propelled equipment on a well pad or associated with a well pad (including well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate).”

Facility Definition for Onshore Petroleum and Natural Gas Production

Reporting under 40 CFR §98 is at the facility level, however due to the unique characteristics of onshore petroleum and natural gas production, the definition of “facility” for this industry segment under Subpart W is distinct from that used for other segments throughout the GHG Reporting Program. 40 CFR §98.238 defines an onshore petroleum and natural gas production facility as:

“All petroleum or natural gas equipment on a well pad or associated with a well pad and CO₂ enhanced oil recovery (EOR) operations that are under common ownership or common control included leased, rented, and contracted activities by an onshore petroleum and natural gas production operator and that are located in a single hydrocarbon basin as defined in §98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.”

**GHGs to Report**

Facilities assessing their applicability in the onshore petroleum and natural gas production segment must only include emissions from equipment, as specified in 40 CFR 98.232(c) and discussed below, to determine if they exceed the 25,000 metric ton CO$_2$ equivalent threshold and thus are required to report their GHG emissions to EPA.\(^\text{18}\)

§98.232(c) specifies that onshore petroleum and natural gas production facilities report CO$_2$, CH$_4$, and N$_2$O emissions from only the following source types:

- Natural gas pneumatic device venting;
- Natural gas driven pneumatic pump venting;
- Well venting for liquids unloading;
- Gas well venting during well completions without hydraulic fracturing;
- Gas well venting during well completions with hydraulic fracturing;
- Gas well venting during well workovers without hydraulic fracturing;
- Gas well venting during well workovers with hydraulic fracturing;
- Flare stack emissions;
- Storage tanks vented emissions from producted hydrocarbons;
- Reciprocating compressor rod packing venting;
- Well testing venting and flaring;
- Associated gas venting and flaring from produced hydrocarbons;
- Dehydrator vents;
- EOR injection pump blowdown;
- Acid gas removal vents;

\(^{18}\) Federal Register, November 30, 2010, p. 77462.
- EOR hydrocarbon liquids dissolved CO₂;
- Centrifugal compressor venting;
- Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps); and
- Stationary and portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at on onshore production well pad. The following equipment is listed within the rule as integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment; workover equipment; natural gas dehydrators; natural gas compressors; electrical generators; steam boilers; and process heaters.

**GHG Emissions Calculations, Monitoring and Quality Assurance**

40 CFR §98.233 prescribes the use of specific equations and methodologies for calculating GHG emissions from each of the source types listed above. The GHG calculation methodologies used in the rule generally include the use of engineering estimates, emissions modeling software, and emission factors, or when other methods are not feasible, direct measurement of emissions.¹⁹ In some cases, the rule allows reporters the flexibility to choose from more than one method for calculating emissions from a specific source type; however, reporters must keep record in their monitoring plans as outlined in 40 CFR 98.3(g).²⁰

Also, for specified time periods during the 2011 data collection year, reporters may use best available monitoring methods (BAMM) for certain emission sources in lieu of the monitoring methods prescribed in §98.233. This is intended to give reporters flexibility as they revise procedures and contractual agreements during early implementation of the rule.²¹

40 CFR §98.234 mandates that the GHG emissions data be quality assured as applicable and prescribes the use of specific methods to conduct leak detection of equipment leaks, procedures to operate and calibrate flow meters, composition analyzers and pressure gages used to measure quantities, and conditions and procedures related to the use of calibrated bags, and high volume

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¹⁹ USEPA Fact Sheet for Subpart W, November 2010.
samplers to measure emissions. Section 98.235 prescribes procedures for estimating missing data.

_Data Recordkeeping and Reporting Requirements_

Title 40 CFR §98.3(c) specifies general recordkeeping and reporting requirements that all facilities required to report under the rule must follow. For example, all reporters must:

- Retain all required records for at least 5 years;
- Keep records in an electronic or hard-copy format that is suitable for expeditious inspection and review;
- Make required records available to the EPA Administrator upon request;
- List all units, operations, processes and activities for which GHG emissions were calculated;
- Provide the data used to calculate the GHG emissions for each unit, operation, process and activity, categorized by fuel or material type;
- Document the process used to collect the necessary data for GHG calculations;
- Document the GHG emissions factors, calculations and methods used;
- Document any procedural changes to the GHG accounting methods and any changes in the instrumentation critical to GHG emissions calculations; and
- Provide a written quality assurance performance plan which includes the maintenance and repair of all continuous monitoring systems, flowmeters and other instrumentation.

40 CFR §98.236 specifies additional reporting requirements that are specific to the Petroleum and Natural Gas Systems covered under Subpart W.

8.1.4 River Basin Commissions

SRBC and DRBC are not directly involved in the well permitting process, and the Department will gather information related to proposed surface water withdrawals that are identified in well permit applications. However, the Department will continue to participate on each Commission to provide input and information regarding projects of mutual interest.
On May 6, 2010 the DRBC announced that it would draft regulations necessary to protect the water resources of the DRB during natural gas development. The drilling pad, accompanying facilities, and locations of water withdrawals were identified as part of the natural gas extraction project and subject to regulation by the DRBC. A draft rule was published in December 2010 and comments were accepted until April 15, 2011. There is no projected date or deadline for the adoption of rule changes.

8.2 Intra-Department

8.2.1 Well Permit Review Process

The Division of Mineral Resources (DMN) would maintain its lead role in the review of Article 23 well permit applications, including review of the fluid disposal plan that is required by 6 NYCRR §554.1(c)(1). The Division of Water would assist in this review if the applicant proposes to discharge either flowback water or production brine to a POTW. The Division of Fish, Wildlife and Marine Resources (DFWMR) would have an advisory role regarding invasive species control, and would assist in the review of site disturbance in Forest and Grassland Focus Areas. The Division of Air Resources would have an advisory role with respect to applicability of various air quality regulations and effectiveness of proposed emission control measures. When a site-specific SEQRA review is required, DMN would be assisted by other appropriate Department programs, depending on the reason that site-specific review is required and the subject matter of the review. The Division of Materials Management (DMM) would review applications for beneficial use of production brine in road-spraying projects.

8.2.1.1 Required Hydraulic Fracturing Additive Information

As set forth in Chapter 5, NYSDOH reviewed information on 322 unique chemicals present in 235 products proposed for hydraulic fracturing of shale formations in New York, categorized them into chemical classes, and did not identify any potential exposure situations that are qualitatively different from those addressed in the 1992 GEIS. The regulatory discussion in Section 8.4 concludes that adequate well design prevents contact between fracturing fluids and fresh ground water sources, and text in Chapter 6 along with Appendix 11 on subsurface fluid mobility explains why ground water contamination by migration of fracturing fluid is not a reasonably foreseeable impact. Chapters 6 and 7 include discussion of how setbacks, inherent mitigating factors, and a myriad of regulatory controls protect surface waters. Chapter 7 also
sets forth a water well testing protocol using indicators that are independent of specific additive chemistry.

For every well permit application the Department would require, as part of the EAF Addendum, identification of additive products by product name and purpose/type, and proposed percent by weight of water, proppants and each additive. This would allow the Department to determine whether the proposed fracturing fluid is water-based and generally similar to the fluid represented by Figures 5.3, 5.4, and 5.5. Additionally, the anticipated volume of each additive product proposed for use would be required as part of the EAF Addendum. Beyond providing information about the quantity of each additive product to be utilized, this requirement informs the Department of the approximate quantity of each additive product that would be on-site for each high-volume hydraulic fracturing operation.

The Department would also require the submittal of an MSDS for every additive product proposed for use, unless the MSDS for a particular product is already on file as a result of the disclosure provided during the preparation process of this SGEIS (as discussed in Chapter 5) or during the application process for a previous well permit. Submittal of product MSDSs would provide the Department with the identities, properties and effects of the hazardous chemical constituents within each additive proposed for use.

Finally, the Department proposes to require that the application materials (i) document the applicant’s evaluation of available alternatives for the proposed additive products that are efficacious but which exhibit reduced aquatic toxicity and pose less risk to water resources and the environment and (ii) contain a statement that the applicant will utilize such alternatives, unless it demonstrates to DMN’s satisfaction that they are not equally effective or feasible. The evaluation criteria should include (1) impact to the environment caused by the additive product if it remains in the environment, (2) the toxicity and mobility of the available alternatives, (3) persistence in the environment, (4) effectiveness of the available alternative to achieve desired results in the engineered fluid system and (5) feasibility of implementing the alternative.

In addition to the above requirements for well permit applications, the Department would continue its practice of requiring hydraulic fracturing information, including identification of

Revised Draft SGEIS 2011, Page 8-30
materials and volumes of materials utilized, on the well completion report\textsuperscript{22} which is required, in accordance with 6 NYCRR §554.7, to be submitted to the Department within 30 days after the completion of any well. This requirement can be utilized by Department staff to verify that only those additive products proposed at the time of application, or subsequently proposed and approved prior to use, were utilized in a given high-volume hydraulic fracturing operation.

The Department has the authority to require, at any time, the disclosure of any additional additive product composition information it deems necessary to ensure that environmental protection and public health and safe drinking water objectives are met, or to respond to an environmental or public health and safety concern. This authority includes the ability to require the disclosure of information considered to be trade secret, so long as such information is handled in accordance with the New York State Public Officer’s Law, POL§89(5), and the Department’s Records Access Regulations, 6 NYCRR §616.7.

In accordance with the discussion in Chapter 7 regarding Publicly Owned Treatment Works (POTWs), the Department proposes to require the disclosure of additional additive composition information as part of any headworks analysis used to determine whether a particular treatment facility can accept flowback or production brine from wells permitted pursuant to this Supplement, or whether a modification to the POTW’s SPDES permit is necessary prior to any acceptance of such fluids. This disclosure however, would be handled separately from the application for permit to drill, as the evaluation of headworks analyses and any necessary SPDES permit modifications would be handled through existing Department processes.

\textit{Public Disclosure of Additive Information}

Although the Department must handle information which is sufficiently justified as trade secret in accordance with existing law and regulation as previously discussed, the Department considers MSDSs to be public information ineligible for exception from disclosure as trade secrets. Therefore, the Department proposes to provide a listing of high-volume hydraulic fracturing additive product names and links to the associated product MSDSs on an individual well basis on its website. This would provide the public with a resource, beyond the Freedom of

\textsuperscript{22} The Well Drilling and Completion Report Form is available on the Department’s website at http://www.dec.ny.gov/docs/materials_minerals_pdf/comp_rpt.pdf.
Information Law, for obtaining information about the additives utilized in high-volume hydraulic fracturing operations in New York, and it would provide the natural gas industry with a resource for determining if a particular product MSDS is already on file with the Department or if an MSDS needs to be submitted at the time a product is proposed for use.

The New York State Public Officer’s Law and the Department’s Records Access Regulations would continue to govern the handling of any other records submitted to the Department as part of the well permit application process, or in response to any Department request for additional additive product composition information.

8.2.2 Other Department Permits and Approvals

The Division of Environmental Permits (DEP) manages most other permitting programs in the Department and is therefore shown in Table 8.1 as having primary responsibility for wetlands permitting, review of new in-state industrial treatment plants, and injection well disposal. The Department’s technical experts on wetlands permitting reside in DFWMR. Technical review of SPDES permits, including for industrial treatment plants, POTWs and injection wells is typically conducted by DOW. Other programs where DOW bears primary responsibility include stormwater permitting, dam safety permitting for freshwater impoundments, and review of headworks analysis to determine acceptability of a POTW’s receiving flowback water. Waste haulers who transport wellsite fluids come under the purview of DER’s Part 364 program, and must obtain a Beneficial Use Determination for road-spreading from DMM. DFWMR would review new proposed surface withdrawals to assist DMN in its determination of whether a site-specific SEQRA determination is required. DAR would have a primary permitting role if emissions at centralized flowback water surface impoundments or well pads trigger regulatory thresholds.

8.2.2.1 Bulk Storage

The Department regulates bulk storage of petroleum and hazardous chemicals under 6 NYCRR Parts 612-614 for Petroleum Bulk Storage (PBS) and Parts 595-597 for Chemical Bulk Storage (CBS). The PBS regulations do not apply to non-stationary tanks; however, all petroleum spills, leaks, and discharges must be reported to the Department (613.8).
The CBS regulations that potentially may apply to fracturing fluids include non-stationary tanks, barrels, drums or other vessels that store 1000 kg or greater for a period of 90 consecutive days. Liquid fracturing chemicals are stored in non-stationary containers but most likely would not be stored on-site for 90 consecutive days; therefore, those chemicals are exempt from Part 596, “Registration of Hazardous Substance Bulk Storage Tanks” unless the storage period criteria are exceeded. These liquids typically are trucked to the drill site in volumes required for consumptive use and only days before the fracturing process. Dry chemical additives, even if stored on site for 90 days, would be exempt from 6 NYCRR because the dry materials are stored in 55-lb bags secured on plastic-wrapped pallets.

The facility must maintain inventory records for all applicable non-stationary tanks including those that do not exceed the 90-day storage threshold. The CBS spill regulations and reporting requirements also apply regardless of the storage thresholds or exemptions. Any spill of a “reportable quantity” listed in Part 597.2(b), must be reported within 2 hours unless the spill is contained by secondary containment within 24 hours and the volume is completely recovered. Spills of any volume must be reported within two (2) hours if the release could cause a fire, explosion, contravention of air or water quality standards, illness, or injury. Forty-two of the chemicals listed in Table 5.7 are listed in Part 597.2(b).

8.2.2.2 Impoundment Regulation

Water stored within an impoundment represents potential energy which, if released, could cause personal injury, property damage and natural resource damage. In order for an impoundment to safely fulfill its intended function, the impoundment must be properly designed, constructed, operated and maintained.

As defined by ECL Section 15-0503, a dam is any artificial barrier, including any earthen barrier or other structure, together with its appurtenant works, which impounds or will impound waters. As such, any engineered impoundment designed to store water for use in hydraulic fracturing operations is considered to be a dam and is therefore subject to regulation in accordance with the ECL, the Department’s Dam Safety Regulations and the associated Protection of Waters permitting program.
Statutory Authority
Chapter 364, Laws of 1999 amended ECL Sections 15-0503, 15-0507 and 15-0511 to revise the applicability criteria for the dam permit requirement and provide the Department the authority to regulate dam operation and maintenance for safety purposes. Additionally the amendments established the dam owners’ responsibility to operate and maintain dams in a safe condition.

Although the revised permit criteria, which are discussed below, became effective in 1999, implementing the regulation of dam operation and maintenance for all dams (regardless of the applicability of the permit requirement) necessitated the promulgation of regulations. As such, the Department issued proposed dam safety regulations in February 2008, followed by revised draft regulations in May 2009 and adopted the amended regulations in August 2009. These adopted regulations contain amendments to Part 673 and to portions of Parts 608 and 621 of Title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York.  

Permit Applicability
In accordance with ECL §15-0503 (1)(a), a Protection of Waters Permit is required for the construction, reconstruction, repair, breach or removal of an impoundment provided the impoundment has:

- a height equal to or greater than fifteen feet; or
- a maximum impoundment capacity equal to or greater than three million gallons.

If, however, either of the following exemption criteria apply, no permit is required:

- a height equal to or less than six feet regardless of the structure’s impoundment capacity; or
- an impoundment capacity not exceeding one million gallons regardless of the structure’s height.

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23 NYSDEC Notice of Adoption of Amendments to Dam Safety Regulations.
24 Maximum height is measured as the height from the downstream [outside] toe of the dam at its lowest point to the highest point at the top of the dam.
25 Maximum impounding capacity is measured as the volume of water impounded when the water level is at the top of the dam.
Figure 8.1 depicts the aforementioned permitting criteria and demonstrates that a permit is required for any impoundment whose height and storage capacity plot above or to the right of the solid line, while those impoundments whose height and storage capacity plot below or to the left of the solid line, do not require a permit.

**Protection of Waters - Dam Safety Permitting Process**

If a proposed impoundment meets or exceeds the permitting thresholds discussed above, the well operator proposing use of the impoundment is required to apply for a Protection of Waters Permit through the Department’s Division of Environmental Permits.

A pre-application conference is recommended and encouraged for permit applicants, especially those who are first-time applicants. Such a conference allows the applicant to explain the
proposed project and to get preliminary answers to any questions concerning project plans, application procedures, standards for permit issuance and information on any other applicable permits pertaining to the proposed impoundment. It is also recommended that this conference occur early in the planning phase, prior to detailed design and engineering work, so that Department staff can review the proposal and comment on its conformance with permit issuance standards, which may help to avoid delays later in the process.

Application forms, along with detailed application instructions are available on the Department’s website and from the Regional Permit Administrator for the county where the impoundment project is proposed. A complete application package must include the following items:

- A completed Joint Application for Permit;
- A completed Application Supplement D-1, which is specific to the construction, reconstruction or repair of a dam or other impoundment structure;
- A location map showing the precise location of the project;
- A plan of the proposed project;
- Hydrological, hydraulic, and soils information, as required on the application form prescribed by the Department;
- An Engineering Design Report sufficiently detailed for Department evaluation of the safety aspects of the proposed impoundment that shall include:
  - A narrative description of the proposed project;
  - The proposed Hazard Classification of the impoundment as a result of the proposed activities or project;
  - A hydrologic investigation of the watershed and an assessment of the hydraulic adequacy of the impoundment;

26 Downloadable permit application forms are available at http://www.dec.ny.gov/permits/6338.html.
27 Contact information for the Department’s Regional Permit Administrators is available on the Department’s website at http://www.dec.ny.gov/about/558.html.
28 Further details regarding the permit application requirement are available on the instructions which accompany the Supplement D-1 application form which is available at http://www.dec.ny.gov/docs/permits_ej_operations_pdf/spplmntd1.pdf.
○ An evaluation of the foundation and surrounding conditions, and materials involved in the structure of the dam, in sufficient detail to accurately define the design of the dam and assess its safety, including its structural stability;

○ Structural and hydraulic design studies, calculation and procedures, which shall, at a minimum, be consistent with generally accepted sound engineering practice in the field of dam design and safety; and

○ A description of any proposed permanent instrument installations in the impoundment; and

- Construction plans and specifications that are sufficiently detailed for Department evaluation of the safety aspects of the dam.

Additionally the following information may also be required as part of the permit application:

- Recent clear photographs of the project site mounted on a separate sheet labeled with the view shown and the date of the photographs;

- Information necessary to satisfy the requirements of SEQRA, including: a completed Environmental Assessment Form (EAF) and, in certain cases, a Draft Environmental Impact Statement (DEIS);

- Information necessary to satisfy the requirements of the State Historic Preservation Act (SHPA) including a completed structural and archaeological assessment form and, in certain cases, an archaeological study as described by SHPA;

- Written permission from the landowner for the filing of the project application and undertaking of the proposed activity; and

- Other information which Department staff may determine is necessary to adequately review and evaluate the application.

In order to ensure that an impoundment is properly designed and constructed, the design, preparation of plans, estimates and specifications, and the supervision of the erection, reconstruction, or repair of an impoundment must be conducted by a licensed professional engineer. This individual should utilize the Department’s technical guidance document.
“Guidelines for Design of Dams,”\textsuperscript{29} which conveys sound engineering practices and outlines hydrologic and other criteria that should be utilized in designing and constructing an engineered impoundment.

All application materials should be submitted to the appropriate Regional Permit Administrator for the county in which the project is proposed. Once the application is declared complete, the Department will review the applications, plans and other supporting information submitted and, in accordance with 6 NYCRR §608.7, may (1) grant the permit; (2) grant the permit with conditions as necessary to protect the health, safety, or welfare of the people of the state, and its natural resources; or (3) deny the permit.

The Department’s review will determine whether the proposed impoundment is consistent with the standards contained within 6 NYCRR §608.8, considering such issues as:

- the environmental impacts of the proposal, including effects on aquatic, wetland and terrestrial habitats; unique and significant habitats; rare, threatened and endangered species habitats; water quality\textsuperscript{30}, hydrology\textsuperscript{31}, water course and waterbody integrity;
- the adequacy of design and construction techniques for the structure;
- operation and maintenance characteristics;
- the safe commercial and recreational use of water resources;
- the water dependent nature of a use;
- the safeguarding of life and property; and
- natural resource management objectives and values.

Additionally, the Department’s review of the proposed impoundment will include the assignment of a Hazard Classification in accordance with 6 NYCRR§673.5. Hazard Classifications are assigned to dams and impoundments according to the potential impacts of a dam failure, the

\textsuperscript{29} “Guidelines for Design of Dams” is available on the Department’s website at http://www.dec.ny.gov/docs/water_pdf/damguideli.pdf or upon request from the DEC Regional Permit Administrator.

\textsuperscript{30} Water Quality may include criteria such as temperature, dissolved oxygen, and suspended solids.

\textsuperscript{31} Hydrology may include such criteria as water velocity, depth, discharge volume, and flooding potential.
particular physical characteristics of the impoundment and its location, and may be irrespective of the size of the impoundment, as appropriate. The four potential Hazard Classifications, as defined by subdivision (b) of Section 673.5, are as follows:

- Class “A” or “Low Hazard”: A failure is unlikely to result in damage to anything more than isolated or unoccupied buildings, undeveloped lands, minor roads such as town or country roads; is unlikely to result in the interruption of important utilities, including water supply, sewage treatment, fuel, power, cable or telephone infrastructure; and/or is otherwise unlikely to pose the threat of personal injury, substantial economic loss or substantial environmental damage;

- Class “B” or “Intermediate Hazard”: A failure may result in damage to isolate homes, main highways, and minor railroads; may result in the interruption of important utilities, including water supply, sewage treatment, fuel, power, cable or telephone infrastructure; and/or is otherwise likely to pose the threat of personal injury and/or substantial economic loss or substantial environmental damage. Loss of human life is not expected;

- Class “C” or “High Hazard”: A failure may result in widespread or serious damage to home(s); damage to main highways, industrial or commercial buildings, railroads, and/or important utilities, including water supply, sewage treatment, fuel, power, cable or telephone infrastructure; or substantial environmental damage; such that the loss of human life or widespread substantial economic loss is likely; and

- Class “D” or “Negligible or No Hazard”: A dam or impoundment that has been breached or removed, or has failed or otherwise no longer materially impounds waters, or a dam that was planned but never constructed. Class “D” dams are considered to be defunct dams posing negligible or no hazard. The Department may retain pertinent records regarding such dams.

The basis for the issuance of a permit will be a determination that the proposal is in the public interest in that the proposal is reasonable and necessary, will not endanger the health, safety or welfare of the people of the State of New York, and will not cause unreasonable, uncontrolled or unnecessary damage to the natural resources of the state.

**Timing of Permit Issuance**

Application submission, time frames and processing procedures for the Protection of Waters Permit are all governed by the provisions of Article 70 of the ECL – the Uniform Procedures Act.
In accordance with subdivision (a)(2)(iii) of Section 621 as recently amended, only repairs of existing dams inventoried by the Department are considered minor projects under the UPA and therefore the construction, reconstruction or removal of an impoundment is considered to be a major project and is thus subject to the associated UPA timeframes.

Failure to obtain the required permit before commencing work subjects the well operator and any contractors engaged in the work to Department enforcement action which may include civil or criminal court action, fines, an order to remove structures or materials or perform other remedial action, or both a fine and an order.

**Operation and Maintenance of Any Impoundment**

The Department’s document “An Owners Guidance Manual for the Inspection and Maintenance of Dams in New York State” should be utilized by all impoundment owners, as it provides important, direct and indirect steps they can take to reduce the consequences of an impoundment failure.

The Dam Safety Regulations, as set forth in 6 NYCRR § 673 and amended August 2009, apply to any owner of any impoundment, regardless of whether the impoundment meets the permit applicability criteria previously discussed (unless otherwise specified). In accordance with the general provisions of Section 673.3, any owner of any impoundment must operate and maintain the impoundment and all appurtenant works in a safe condition. The owner of any impoundment found to be in violation of this requirement is subject to the provisions of ECL 15-0507 and 15-0511.

In order to ensure the safe operation and maintenance of an impoundment, a written Inspection and Maintenance Plan is required under 6 NYCRR §673.6 for any impoundment that (1) requires a Protection of Waters Permit due to its height and storage capacity as previously discussed, (2) has been assigned a Hazard Classification of Class “B” or “C”, or (3) impounds waters which pose a threat of personal injury, substantial property damage or substantial natural resources damage in the event of a failure, as determined by the Department. Such a plan shall be retained
by the impoundment owner and updated as necessary, must be made available to the Department upon request, and must include:

- detailed descriptions of all procedures governing: the operation, monitoring, and inspection of the dam, including those governing the reading of instruments and the recording of instrument readings; the maintenance of the dam; and the preparation and circulation of notifications of deficiencies and potential deficiencies;

- a schedule for monitoring, inspections, and maintenance; and

- any other elements as determined by the Department based on its consideration of public safety and the specific characteristics of the dam and its location.

Additionally, the owner of any impoundment assigned a Hazard Classification of Class “B” or “C” must, in accordance with 6 NYCRR §673, prepare an Emergency Action Plan and annual updates thereof, provide a signed Annual Certification to the Department’s Dam Safety Section, conduct and report on Safety Inspections on a regular basis, and provide regular Engineering Assessments. Furthermore, all impoundment structures are subject to the Recordkeeping and Response to Request for Records provision of 6 NYCRR.

All impoundment structures, regardless of assigned Hazard Classification or permitting requirements, are subject to field inspections by the Department at its discretion and without prior notice. During such an inspection, the Department may document existing conditions through the use of photographs or videos without limitation. Based on the field inspection, the Department may create a Field Inspection Report and, if such a report is created for an impoundment with a Class “B” or “C” Hazard Classification, the Department will provide a copy of the report to the chief executive officer of the municipality or municipalities in which the impoundment is located.

To further ensure the safe operation and maintenance of all impoundments, 6 NYCRR §673.17 allows the Department to direct an impoundment owner to conduct studies, investigations and analyses necessary to evaluate the safety of the impoundment, or to remove, reconstruct or repair the impoundment within a reasonable time and in a manner specified by the Department.
8.2.3 Enforcement

Although DMN would retain a lead role in the review of Article 23 well permit applications and DOW would be responsible for implementing the HVHF GP and approving the discharge from POTWs who may accept waste from drilling operations, enforcement of violations of the ECL will require a multi-divisional approach. The SGEIS addresses a broad range of topics and requires mitigation for all aspects of a well drilling operation beginning with the source of fresh water for hydraulic fracturing and proceeding long after production wells are drilled. Some of the proposed mitigation measures identified in Chapter 7 would take the form of permit conditions attached, as appropriate, to the permit to drill issued pursuant to ECL Article 23. However, most of the proposed mitigation measures will be set forth as revisions or additions to the Department’s regulations. Appendix 10 contains proposed supplementary permit conditions for high-volume hydraulic fracturing, most of which will become revisions or additions to the Department’s regulations. Failure of a well operator to adhere to conditions of the permit would be considered a violation of ECL Article 23 and the failure of a well operator to comply with the HVHF GP would be considered a violation of ECL Article 17. Failure of an operator to follow the regulations of the Department would be considered a violation of the ECL Article 71.

While there are several different types of approvals needed from the Department in order to site wells for high-volume hydraulic fracturing in New York, there are two permits that would be specifically issued by the Department: the Article 23 permit to drill and the HVHF GP. For informational purposes, a more detailed description of how those permits would be enforced is provided below. This description is not intended to be exhaustive, since the type of enforcement response depends entirely on the nature of the violation. For more detailed descriptions of the Department’s regulations and enforcement policies, the Department’s website should be consulted.

8.2.3.1 Enforcement of Article 23

The Oil, Gas & Solution Mining Law vests the Department with the authority to regulate the development, production and utilization of the state’s natural energy resources. There are three essential policy objectives embodied in ECL 23. Those objectives are to: 1) to prevent waste of the oil and gas resource as “waste” is defined in the statute; 2) to provide for the operation and development of oil and gas properties to provide for greater ultimate recovery of the resource,
and; 3) to protect the correlative rights of all owners and the general public. To carry out these objectives, ECL 23 specifically provides the Department with the authority to, among other things:

“Require the drilling, casing, operation, plugging and replugging of wells and reclamation of surrounding land in accordance with rules and regulations of the department in such manner as to prevent or remedy the following, including but not limited to: the escape of oil, gas, brine or water out of one stratum into another; the intrusion of water into oil or gas strata other than during enhanced recovery operations; the pollution of fresh water supplies by oil, gas salt water or other contaminants; and blowouts, cavings, seepages and fires.” ECL 23-0305(8)(d).

Along with other powers enumerated in ECL 23, this broad grant of authority is implemented through the Department’s oil and gas well regulations, found at 6 NYCRR Part 550, and through the imposition of conditions attached to a permit to drill issued by the Division of Mineral Resources. ECL Article 71 makes it unlawful for any person to fail to perform a duty imposed by ECL 23 or to violate any order or permit condition issued by the Department. Therefore, a failure of an operator to comply with a permit to drill exposes the well operator to an enforcement action. Enforcement actions may be pursued through administrative, civil or criminal means, depending on the nature of the violation. The Department may also call upon the Attorney General to obtain injunctive relief against any person violating or threatening to violate ECL 23.

Violations which are pursued administratively may result in an Order on Consent, which is a settlement agreement signed by the Department and the well operator. There are two Department policy documents which describe penalty calculations and the necessary components of an Order and Consent: DEE-1, Civil Penalty Policy, and: DEE-2, Order on Consent Enforcement Policy. Both policies can be found on the Department’s website at: http://www.dec.ny.gov/regulations/2379.html. In cases where a settlement is not reached, a hearing may be held pursuant to the Department’s Uniform Enforcement Hearing Procedures.
The Oil, Gas & Solution Mining Law also provides the Department with the administrative power to shut-in drilling or production operations whenever those operations fail to comply with ECL 23, the Department’s regulations or any order issued by the Department. This power, found in ECL 23-0305(8)(g), is injunctive in nature and allows the Department to immediately address a violation without the need for a court order. This is an effective enforcement tool, particularly in the case of producing wells since the Department, through 6 NYCRR Part 558, may serve the shut-in order on a pipeline company or carrier, preventing them from transporting product from an operator found in violation of Article 23.

8.2.3.2 Enforcement of Article 17
The Department will take appropriate action to ensure all regulated point source and non-point source dischargers comply with applicable laws and regulations to protect public health and the intended best use of the waters of the state in accordance with “Technical and Operational guidance Series (TOGS) 1.4.2 – Compliance and Enforcement of State Pollutant Discharge Elimination System (SPDES) Permits.” This guidance applies to all SPDES permits, including individual and general permits.

TOGS 1.4.2 supplements existing Department policy regarding civil enforcement actions for dischargers subject to individual and general permits and provides the minimum enforcement response and penalty (if applicable). When appropriate, more stringent enforcement responses may be utilized.

The focus of compliance and enforcement activities is based on resolving priority violations. Any point source or non-point source discharge to an identified current year CWA Section 303(d) List of Impaired Waters segment; water bodies with a TMDL strategy or other restoration measure; or a sole-source and/or primary aquifer is also a priority. Discharges from non-significant class facilities and unregulated non-point source discharges remain subject to compliance and enforcement activities as necessary for the protection of public health and the intended best use of the waters of the state.

Protection of the state’s water resources is required regardless of the Department’s compliance and enforcement priorities. Any discharge that causes or contributes to a contravention of the
water quality standards contained in 6 NYCRR Part 700 et seq. (or guidance values adopted pursuant thereto), or impairs the quality of waters, or otherwise creates a nuisance or menace to health, is a violation of ECL Article 17 and is subject to enforcement.

Discharging without the appropriate permit is a violation of ECL Article 17 and 6 NYCRR Part 750. A facility discharging without a permit is subject to enforcement prior to issuance of a permit. Therefore, processing and review of a permit application may be suspended if an enforcement action is commenced.

SPDES Compliance Evaluation

SPDES permits are issued to wastewater and stormwater dischargers for the protection of the waters of the State. Operation and maintenance of SPDES-permitted facilities must comply with applicable regulations pursuant to 6 NYCRR Part 750 and additional facility specific and general permit conditions. When conditions of a permit, enforcement order or court decree are not met or not implemented according to a schedule, water quality may be negatively impacted. Permit compliance leads to protection of the public health and the intended best use of the waters of the state.

The Department’s SPDES permit compliance program is directly supported by the following elements which allow the Department to evaluate the compliance status of any regulated facility and determine whether violations have or may occur:

**Periodic Self-Reporting** - The Department controls discharges of pollutants from some SPDES permitted facilities by establishing pollutant specific effluent limits and operating conditions in the permit and/or Order on Consent. Compliance with these limitations and conditions via self-reporting is critical to the protection of water quality.

Some SPDES permits and Orders on Consent require reporting of pollutants that are discharged on a Discharge Monitoring Report (DMR). The DMR is used by the Department to evaluate a facility’s compliance with permit limitations. The information reported on DMRs is entered into a database system for compliance assessment, tracking and reporting purposes. Timely and accurate filing of DMRs is vital to ensuring compliance with the permit.
The Division of Water (DOW) also relies on other reports (e.g., monthly operating, annual, toxicity testing and status reports) and notifications (e.g., completion of permit or Order on Consent compliance schedules), to determine the compliance status of a facility. These documents may supplement or be submitted in lieu of a DMR, as specified in each permit or enforcement order.

__Inspections__ - The Department conducts site inspections and effluent sampling to monitor facility performance, and to detect, identify and assess the magnitude of violations by a discharger. The primary focus for inspections of individually permitted facilities is on major and significant minor point source discharges and facilities that pose the highest risk to public health and safety. The number and type of inspections to be performed at permitted facilities are determined during DOW’s annual work planning process. The primary focus for inspections of general permitted facilities is established annually through the same work planning process. Standardized inspection forms have been developed to assist Department inspectors in assessing the compliance status of dischargers in relation to the permit conditions, regulatory and record keeping requirements. Additional inspection forms may be developed to comprehensively evaluate compliance with permits issued for this activity.

Inspection information is entered into a database system for compliance evaluation, tracking and reporting purposes. Inspection findings can be rated “satisfactory,” “marginal” or “unsatisfactory.” An unsatisfactory rating is considered a priority and may be subject to informal and/or formal enforcement.

The Department may use inspection information provided by federal, state and local governmental entities to supplement compliance evaluations.

__Citizen Complaints__ - Citizen complaints and observations of possible violations may assist the Department's compliance and enforcement efforts for SPDES permits. The Department will evaluate the authenticity of alleged violations and impacts to the environment and/or public health and safety to determine an appropriate response. This response may include enforcement. A “Notice of Intent to Sue” is a formal legal letter of intent to commence a federal “citizens suit” that is served by private parties alleging violations of federal environmental laws.
specifically the federal Clean Water Act (CWA). The Department has established a systematic approach in reviewing and responding to such Notices.

SPDES Enforcement

The Department detects, investigates and resolves violations which are likely to impact the public health or the water quality of the state. Staff will respond to each water priority violation using the appropriate tools, including formal enforcement actions if necessary, to expedite a return to compliance. To promote statewide consistency in the handling of water priority violations in all SPDES programs, TOGS 1.4.2 contains a SPDES compliance and enforcement response guide allowing staff to determine when enforcement is necessary to bring the facility back to compliance. TOGS 1.4.2 describes the range of options available to the Department for enforcement, ranging from warning letters and compliance conferences through more formal proceedings involving hearings, summary abatement orders and referral to the Attorney General’s Office. For a more detailed description of all the avenues available to the Department for SPDES enforcement, TOGS 1.4.2 can be viewed at on the Department’s website at: http://www.dec.ny.gov/docs/water_pdf/togs142.pdf.

SPDES Enforcement Coordination with EPA

The Department’s obligations with respect to compliance and enforcement of SPDES permits are specified in the 1987 Enforcement Agreement between Region II of the USEPA and the Department. This agreement outlines the elements essential to ensure compliance by the regulated community. Some of these important elements are: monitoring permit compliance; maintaining and sharing compliance information with EPA; identifying criteria for significant non-compliance; listing facilities that require action by the Department to require non-complying facilities to return to compliance; and timely and appropriate enforcement for priority violations. The Department meets with EPA on a quarterly basis to cooperatively address priority violations at major facilities and agree on enforcement responses to these violations and other significant issues such as treatment plant bypasses, manure spills and citizen complaints.

Goals for the Department’s water compliance assurance activities are defined in the Division of Water annual work planning process. The work plan identifies goals for activities such as for the
numbers of inspections of facilities, management of data and number of enforcement actions. The work plan also sets priorities to meet the compliance goals set by the Department and EPA.

Region II EPA also enters into an annual inspection work plan agreement with the Department’s Division of Water. The EPA inspection work plan identifies roles and responsibilities for EPA, communication and coordination protocols with Department. Enforcement response to violations detected by EPA inspections may be conducted by EPA and/or the Department depending on the situations. The Division of Water work plan and the EPA inspection work plan may be modified to account for permits required by this activity.

8.3 Well Permit Issuance

8.3.1 Use and Summary of Supplementary Permit Conditions for High-Volume Hydraulic Fracturing

A generic environmental impact statement addresses common impacts and identifies common mitigation measures. The proposed Supplementary Permit Conditions for high-volume hydraulic fracturing capture the mitigation measures identified as necessary by this review (see Appendix 10). These proposed conditions, some or all of which may be promulgated in revised regulations, address all aspects of well pad activities, including:

- Planning and local coordination;
- Site preparation;
- Site maintenance;
- Drilling, stimulation (i.e., hydraulic fracturing) and flowback operations;
- Reclamation; and
- Other general aspects of the activity.

8.3.2 High-Volume Re-Fracturing

Because of the potential associated disturbance and impacts, the Department proposes that high-volume re-fracturing require submission of the EAF Addendum and the Department’s approval after:
- review of the planned fracturing procedures and products, water source, proposed site disturbance and layout, and fluid disposal plans;

- a site inspection by Department staff; and

- a determination of whether any other Department permits are required.

### 8.4 Other States’ Regulations

The Department committed in Section 2.1.2 of the Final Scope for this SGEIS to evaluate the effectiveness of other states’ regulations with respect to hydraulic fracturing and to consider the advisability of adopting additional protective measures based on those that have proven successful in other states for similar activities. Department staff consulted the following sources to conduct this evaluation:

1) *Ground Water Protection Council, 2009b.* The Ground Water Protection Council (GWPC) is an association of ground water and underground injection control regulators. In May 2009, GWPC reported on its review of the regulations of 27 oil and gas producing states. The stated purpose of the review was to evaluate how the regulations relate to direct protection of water resources:

2) *ICF International, 2009a.* NYSERDA contracted ICF International to conduct a regulatory analysis of New York and up to four other shale gas states regarding notification, application, review and approval of hydraulic fracturing and re-fracturing operations. ICF’s review included Arkansas (Fayetteville Shale), Louisiana (Haynesville Shale), Pennsylvania (Marcellus Shale) and Texas (Barnett Shale);

3) *Alpha Environmental Consultants, Inc., 2009.* NYSERDA contracted Alpha Environmental Consultants, Inc., to survey policies, procedures, regulations and recent regulatory changes related to hydraulic fracturing in Pennsylvania, Colorado, New Mexico, Wyoming, Texas (including the City of Fort Worth), West Virginia, Louisiana, Ohio and Arkansas. Based on its review, Alpha summarized potential permit application requirements to evaluate well pad impacts and also provided recommendations for minimizing the likelihood and impact of liquid chemical spills that are reflected elsewhere in this SGEIS;
4) **Colorado Oil & Gas Conservation Commission, Final Amended Rules.** In the spring of 2009, the Colorado Oil & Gas Conservation Commission adopted new regulations regarding, among other things, the chemicals that are used at wellsites and public water supply protection. Colorado’s program was included in Alpha’s regulatory survey, but the amended rules’ emphasis on topics pertinent to this SGEIS led staff to do a separate review of the regulations related to chemical use and public water supply buffer zones;

5) **June 2009 Statements on Hydraulic Fracturing from State Regulatory Officials.** On June 4, 2009, GWPC’s president testified before Congress (i.e., the House Committee on Natural Resources’ Subcommittee on Energy and Mineral Resources) regarding hydraulic fracturing. Attached to his written testimony were letters from regulatory officials in Ohio, Pennsylvania, New Mexico, Alabama and Texas. These officials unanimously stated that no instances of ground water contamination directly attributable to the hydraulic fracturing process had been documented in their states. Also in June 2009, the Interstate Oil and Gas Compact Commission compiled and posted on its website statements from oil and gas regulators in 12 of its member states: Alabama, Alaska, Colorado, Indiana, Kentucky, Louisiana, Michigan, Oklahoma, Tennessee, Texas, South Dakota and Wyoming. These officials also unanimously stated that no verified instances of harm to drinking water attributable to hydraulic fracturing had occurred in their states despite use of the process in thousands of wells over several decades. All 15 statements are included in Appendix 15;

6) Pennsylvania Environmental Quality Board. Title 25-Environmental Protection, Chapter 78, Oil and Gas Wells, Pennsylvania Bulletin, Col. 41. No. 6 (February 5, 2011); and

7) Statement by Lisa Jackson, EPA Administrator on May 24, 2011 at a House Committee on Oversight and Government Reform that she is “not aware of any proven case where the fracturing process itself has affected water.”

Additional information is provided below regarding the findings and conclusions expressed by GWPC, ICF and Alpha that are most relevant to the mitigation approach presented in this

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32 [http://www.iogcc.state.ok.us/hydraulic-fracturing](http://www.iogcc.state.ok.us/hydraulic-fracturing).
SGEIS. Pertinent sections of Colorado’s final amended rules are also summarized, and a brief discussion of Pennsylvania’s recent revisions to its Chapter 78 Rules is presented.

8.4.1 Ground Water Protection Council

GWPC’s overall conclusion, based on its review of 27 states’ regulations, including New York’s, is that state oil and gas regulations are adequately designed to directly protect water resources. Hydraulic fracturing is one of eight topics reviewed. The other seven topics were permitting, well construction, temporary abandonment, well plugging, tanks, pits and waste handling/spills.

Emphasis on proper well casing and cementing procedures is identified by GWPC and state regulators as the primary safeguard against groundwater contamination during the hydraulic fracturing procedure. This approach has been effective, based on the regulatory statements summarized above and included in the Appendices. Improvements to casing and cementing requirements, along with enhanced requirements regarding other activities such as pit construction and maintenance, are appropriate responses to problems and concerns that arise as technologies advance. Chapters 7 and 8 of this SGEIS, on mitigation measures and the permit process, reflect consideration of requirements regarding either hydraulic fracturing or ancillary activities in other states that address potential impacts associated with horizontal drilling and high-volume hydraulic fracturing that are not covered by the 1992 GEIS.

8.4.1.1 GWPC - Hydraulic Fracturing

With respect to the specific topic of hydraulic fracturing, GWPC found that states generally focus on well construction (i.e., casing and cement) and noted the importance of proper handling and disposal of materials. GWPC recommends identification of fracturing fluid additives and concentrations, as well as 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. GWPC did not provide thresholds for defining when hydraulic fracturing should be considered “shallow” or “in close proximity” to underground sources of drinking water. GWPC did not recommend additional controls on the actual conduct of the hydraulic fracturing procedure itself for deep non-coalbed methane wells that are not in close proximity to drinking water sources, nor did GWPC suggest any restrictions on fracture fluid composition for such wells.
GWPC urges caution against developing and implementing regulations based on anecdotal evidence alone, but does recommend continued investigation of complaints of ground water contamination to determine if a causal relationship to hydraulic fracturing can be established.

8.4.1.2 GWPC - Other Activities
Of the other seven topic areas reviewed by GWPC, permitting, well construction, tanks, pits and waste handling and spills are addressed by this SGEIS. GWPC’s recommendations regarding each of these are summarized below.

Permitting
Unlike New York, in many states the oil and gas regulatory authority is a separate agency from other state-level environmental programs. GWPC recommends closer, more formalized cooperation in such instances. Another suggested action related to permitting is that states continue to expand use of electronic data management to track compliance, facilitate field inspections and otherwise acquire, store, share, extract and use environmental data.

Well Construction
GWPC recommends adequate surface casing and cement to protect ground water resources, adequate cement on production casing to prevent upward migration of fluids during all reservoir conditions, use of centralizers and the opportunity for state regulators to witness casing and cementing operations.

Tanks
Tanks, according to GWPC, should be constructed of materials suitable for their usage. Containment dikes should meet a permeability standard and the areas within containment dikes should be kept free of fluids except for a specified length of time after a tank release or a rainfall event.

Pits
GWPC’s recommendations target “long-term storage pits.” Permeability and construction standards for pit liners are recommended to prevent downward migration of fluids into ground water. Excavation should not be below the seasonal high water table. GPWC recommends against use of long-term storage pits where underlying bedrock contains seepage routes, solution
features or springs. Construction requirements to prevent ingress and egress of fluids during a flood should be implemented within designated 100-year flood boundaries. Pit closure specifications should address disposition of fluids, solids and the pit liner. Finally, GWPC suggests prohibiting the use of long-term storage pits within the boundaries of public water supply and wellhead protection areas.

Waste Handling and Spills

In the area of waste handling, GWPC’s suggests actions focused on surface discharge because “approximately 98% of all material generated . . . is produced water,” and injection via disposal wells is highly regulated. Surface discharge should not occur without the issuance of an appropriate permit or authorization based on whether the discharge could enter water. As reflected in Colorado’s recently amended rules, soil remediation in response to spills should be in accordance with a specific cleanup standard such as a Sodium Absorption Ratio (SAR) for salt-affected soil.

8.4.2 Alpha’s Regulatory Survey

Topics reviewed by Alpha include: pit rules and specifications, reclamation and waste disposal, water well testing, fracturing fluid reporting requirements, hydraulic fracturing operations, fluid use and recycling, materials handling and transport, minimization of potential noise and lighting impacts, setbacks, multi-well pad reclamation practices, naturally occurring radioactive materials and stormwater runoff. Alpha supplemented its regulatory survey with discussion of practices directly observed during field visits to active Marcellus sites in the northern tier of Pennsylvania (Bradford County).

8.4.2.1 Alpha - Hydraulic Fracturing

Alpha’s review with respect to the specific hydraulic fracturing procedure focused on regulatory processes, i.e., notification, approval and reporting. Among the states Alpha surveyed, Wyoming appears to require the most information.

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Pre-Fracturing Notification and Approval

Of the nine states Alpha surveyed, West Virginia, Wyoming, Colorado and Louisiana require notification or approval prior to conducting hydraulic fracturing operations. Pre-approval for hydraulic fracturing is required in Wyoming, and the operator would provide information in advance regarding the depth to perforations or the open hole interval, the water source, the proppants and estimated pump pressure. Consistent with GWPC’s recommendation, information required by Wyoming Oil and Gas Commission Rules also includes the trade name of fluids.

Post-Fracturing Reports

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

8.4.2.2 Alpha - Other Activities

The Department’s development of the overall mitigation approach proposed in this SGEIS also considered Alpha’s discussion of other topics included in the regulatory survey. Key points are summarized below.

Pit Rules and Specifications

Alpha’s review focused on reserve pits at the well pad. Several states have some general specifications in common. These include:

- Freeboard monitoring and maintenance of minimum freeboard;
- Minimum vertical separation between the seasonal high ground water table and the pit bottom, commonly 20 inches;
- Minimum liner thickness of 20 – 30 mil, and maximum liner permeability of $1 \times 10^{-7}$ cm/sec;
- Compatibility of liner material with the chemistry of the contained fluid, placement of the liner with sufficient slack to accommodate stretching, installation and seaming in accordance with the manufacturer’s specifications;

- Construction to prevent surface water from entering the pit;

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

- Pit sidewall slopes from 2:1 to 3:1.

Alpha recommends that engineering judgment be applied on a case-by-case basis to determine the extent of vertical separation that should be required between the pit bottom and the seasonal high water table. Consideration should be given to the nature of the unconsolidated material and the water table; concern may be greater, for example, in a lowland area with high rates of inflow from medium- to high-permeability soils than in upland till-covered areas.

Reclamation and Waste Disposal

In addition to its regulatory survey, Alpha also reviewed and discussed best management practices directly observed in the northern tier of Pennsylvania and noted that “[t]he reclamation approach and regulations being applied in PA may be an effective analogue going forward in New York.”

The best management practices referenced by Alpha include:

- Use of steel tanks to contain flowback water at the well pad;

- On-site or offsite flowback water treatment for re-use, with residual solids disposed or further treated for beneficial use or disposal in accordance with Pennsylvania’s regulations;

- Offsite treatment and disposal of production brine;

- On-site encapsulation and burial of drill cuttings if they do not contain constituents at levels that exceed Pennsylvania’s environmental standards;

- Containerization of sewage and putrescible waste and transport off-site to a regulated sewage treatment plant or landfill;

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• Secondary containment structures around petroleum storage tanks and lined trenches to direct fluids to lined sumps where spills can be recovered without environmental contamination; and

• Partial reclamation of well pad areas not necessary to support gas production.

Alpha noted that perforating or ripping the pit liner prior to on-site burial could prevent the formation of an impermeable barrier or the formation of a localized area of poor soil drainage. Addition of fill may be advisable to mitigate subsidence as drill cuttings dewater and consolidate.\(^{35}\)

**Water Well Testing**

Of the jurisdictions surveyed, Colorado and the City of Fort Worth have water well testing requirements specifically directed at unconventional gas development within targeted regions. Colorado’s requirements are specific to two particular situations: drilling through the Laramie Fox Hills Aquifer and drilling coal-bed methane wells. Fort Worth’s regulations pertain to Barnett Shale development, where horizontal drilling and high-volume hydraulic fracturing are performed, and address all fresh water wells within 500 feet of the surface location of the gas well. Ohio requires sampling of wells within 300 feet prior to drilling within urbanized areas. West Virginia also has testing requirements for wells and springs within 1,000 feet of the proposed oil or gas well. Louisiana, while it does not require testing, mandates that the results of voluntary sampling be provided to the landowner and the regulatory agency.

Pennsylvania regulations presume the operator to be the cause of adverse water quality impacts unless demonstrated otherwise by pre-drilling baseline testing, assuming permission was given by the landowner. Alpha suggests that the following guidance provided by Pennsylvania and voluntarily implemented by operators in the northern tier of Pennsylvania and southern tier of New York should be effective:

• With the landowner’s permission, monitor the quality of any water supply within 1,000 feet of a proposed drilling operation (at least one operator expands the radius to 2,000 feet if there are no wells within 1,000 feet);
• Analyze the water samples using an independent, state certified, water testing laboratory;
  and
• Analyze the water for sodium, chlorides, iron, manganese, barium and arsenic (Alpha recommends analysis for methane types, total dissolved solids, chlorides and pH).

Fluid Use and Recycling

Regarding surface water withdrawals, Alpha found that the most stringent rules in the states surveyed are those implemented in Pennsylvania by the Delaware and Susquehanna River Basin Commissions.

None of the states surveyed have any requirements, rules or guidance relating to the use of treated municipal waste water.

Ohio allows the re-use of drilling and flowback water for dust and ice control with an approval resolution, and will consider other options depending on technology. West Virginia recommends that operators consider recycling flowback water.

Practices observed in the northern tier of Pennsylvania include treatment at the well pad to reduce TDS levels below 30,000 ppm. The treated fluids are diluted by mixing with fresh makeup water and used for the next fracturing project.

Materials Handling and Transport

Alpha provided the review of pertinent federal and state transportation and container requirements that is included in Section 5.5, and concluded that motor transport of all hazardous fracturing additives or mixtures to drill sites is adequately covered by existing federal and NYSDOT regulations. Best management practices such as the following were identified by Alpha for implementation on the well pad:

• Monitoring and recording inventories;
• Manual inspections;
• Berms or dikes;

36 Alpha, 2009, p. 2-31
- Secondary containment;
- Monitored transfers;
- Stormwater runoff controls;
- Mechanical shut-off devices;
- Setbacks;
- Physical barriers; and
- Materials for rapid spill cleanup and recovery.

Minimization of Potential Noise and Lighting Impacts

Colorado, Louisiana, and the City of Fort Worth address noise and lighting issues. Ohio specifies that operations be conducted in a manner that mitigates noise. With respect to noise mitigation, sample requirements include:

- Ambient noise level determination prior to operations;
- Daytime and nighttime noise level limits for specified zones (in Colorado, e.g., residential/agricultural/rural, commercial, light industrial and industrial) or for distances from the wellsite, and periodic monitoring thereof;
- Site inspection and possibly sound level measurements in response to complaints;
- Direction of all exhaust sources away from building units; and
- Quiet design mufflers or equivalent equipment within 400 feet of building units.

The City of Fort Worth has much more detailed noise level requirements and also sets general work hour and day of the week guidelines for minimizing noise impacts, in consideration of the population density and urban nature of the location where the activity occurs.

Alpha found that lighting regulations, where they exist, generally require that site lighting be directed downward and internally to the extent practicable. Glare minimization on public roads and adjacent buildings is a common objective, with a target distance of 300 feet from the well in
Louisiana and Fort Worth and 700 feet from the well in Colorado. Lighting impact considerations would be balanced against the safety of well site workers.

**Setbacks**

Alpha’s setback discussion focused on water resources and private dwellings. The setback ranges in Table 8.3 were reported regarding the surveyed jurisdictions.
<table>
<thead>
<tr>
<th></th>
<th>Water Resources</th>
<th>Private Dwellings</th>
<th>Measured From</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arkansas</td>
<td>200 feet from surface waterbody or wetland, or 300 feet for streams or rivers designated as Extraordinary Resource Water, Natural and Scenic Waterway, or Ecologically Sensitive Water Body</td>
<td>200 feet, or 100 feet with owner’s waiver</td>
<td>Storage tanks</td>
</tr>
<tr>
<td>Colorado</td>
<td>300 feet (“internal buffer;” applies only to classified water supply segments – see discussion below)</td>
<td>Not reported</td>
<td>Surface operation, including drilling, completion, production and storage</td>
</tr>
<tr>
<td>Louisiana</td>
<td>Not reported</td>
<td>500 feet, or 200 feet with owner’s consent</td>
<td>Wellbore</td>
</tr>
<tr>
<td>New Mexico</td>
<td>300 feet from continuously flowing water course; 200 feet from other significant water course, lake bed, sinkhole or playa lake; 500 feet from private, domestic, fresh water wells or springs used by less than 5 households; 1000 feet from other fresh water wells or springs; 500 feet from wetland; pits prohibited within defined municipal fresh water well field or 100-year floodplain</td>
<td>300 feet</td>
<td>Any pit, including fluid storage, drilling circulation and waste disposal pits</td>
</tr>
<tr>
<td>Ohio</td>
<td>200 feet from private water supply wells</td>
<td>100 feet</td>
<td>Wellhead</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>200 feet from water supply springs and wells; 100 feet from surface water bodies and wetlands</td>
<td>200 feet</td>
<td>Well pad limits and access roads</td>
</tr>
<tr>
<td>City of Fort Worth</td>
<td>200 feet from fresh water well</td>
<td>600 feet, or 300 feet with waiver</td>
<td>Wellbore surface location for single-well pads; closest point on well pad perimeter for multi-well sites</td>
</tr>
<tr>
<td>Wyoming</td>
<td>350 feet from water supplies</td>
<td>350 feet</td>
<td>Pits, wellheads, pumping units, tanks and treatment systems</td>
</tr>
</tbody>
</table>
**Multi-Well Pad Reclamation Practices**

Except for Pennsylvania, Alpha found that the surveyed jurisdictions treat multi-well pad reclamation similarly to single well pads. Pennsylvania implements requirements for best management practices to address erosion and sediment control.

As with single well pads, partial reclamation after drilling and fracturing are done would include closure of pits and revegetation of areas that are no longer needed.

**Stormwater Runoff**

Most of the reviewed states have stormwater runoff regulations or best management practices for oil and gas well drilling and development. Alpha suggests that Pennsylvania’s approach of reducing high runoff rates and associated sediment control by inducing infiltration may be a suitable model for New York. Perimeter berms and filter fabric beneath the well pad allow infiltration of precipitation. Placement of a temporary berm across the access road entrance during a storm prevents rapid discharge down erodible access roads that slope downhill from the site.

8.4.3 **Colorado’s Final Amended Rules**

Significant changes were made to Colorado’s oil and gas rules in 2008 that became effective in spring 2009. While many topics were addressed, the new rules related to chemical inventorying and public water supply protection are most relevant to the topics addressed by this SGEIS.

8.4.3.1 **Colorado - New MSDS Maintenance and Chemical Inventory Rule**

The following information is from a training presentation posted on COGCC’s website. The new rule’s objective is to assist COGCC in investigation of spills, releases, complaints and exposure incidents. The rule requires the operators to maintain a chemical inventory of chemical products brought to a well site for downhole use, if more than 500 pounds is used or stored at the site for downhole use or if more than 500 pounds of fuel is stored at the well site during a quarterly reporting period. The chemical inventory, which is not submitted to the COGCC unless requested, includes:

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37 http://cogcc.state.co.us; “Final Amended Rules” and “Training Presentations” links, 7/8/2009.
- MSDS for each chemical product;
- How much of the chemical product was used, how it was used, and when it was used;
- Identity of trade secret chemical products, but not the specific chemical constituents; and
- Maximum amount of fuel stored.

The operator must maintain the chemical inventory and make it available for inspection in a readily retrievable format at the operator’s local field office for the life of the wellsite and for five years after plugging and abandonment.

MSDSs for proprietary products may not contain complete chemical compositional information. Therefore, in the case of a spill or complaint to which COGCC must respond, the vendor or service provider must provide COGCC a list of chemical constituents in any trade secret chemical product involved in the spill or complaint. COGCC may, in turn, provide the information to the Colorado Department of Public Health and Environment (CDPHE). The vendor or service provider must also disclose this list to a health professional in response to a medical emergency or when needed to diagnose and treat a patient that may have been exposed to the product. Health professionals’ access to the more detailed information which is not on MSDSs is subject to a confidentiality agreement. Such information regarding trade secret products provided to the COGCC or to health professionals does not become part of the chemical inventory and is not considered public information.

8.4.3.2 Colorado - Setbacks from Public Water Supplies

The following information was provided by Alpha and supplemented from a training presentation posted on COGCC’s website.\(^{38}\)

Colorado’s new rules require buffer zones along surface water bodies in surface water supply areas. Buffer zones extend five miles upstream from the water supply intake and are measured from the ordinary high water line of each bank to the near edge of the disturbed area at the well location. The buffer applies to surface operations only and does not apply to areas that do not

\(^{38}\) [http://cogcc.state.co.us; “Final Amended Rules” and “Training Presentations” links, 7/8/2009](http://cogcc.state.co.us; “Final Amended Rules” and “Training Presentations” links, 7/8/2009).
drain to classified water supply systems. The buffers are designated as internal (0-300 feet), intermediate (301-500 feet) and external (501-2,640 feet).

Activity within the internal buffer zone requires a variance and consultation with the CDPHE. Within the intermediate zone, pitless (i.e., closed-loop) drilling systems are required, flowback water must be contained in tanks on the well pad or in an area with down gradient perimeter berming, and berms or other containment devices are required around production-related tanks. Pitless drilling or specified pit liner standards are required in the external buffer zone. Water quality sampling and notification requirements apply within the intermediate and external buffer zones.

8.4.4 Summary of Pennsylvania Environmental Quality Board. Title 25-Environmental Protection, Chapter 78, Oil and Gas Wells

A number of Pennsylvania’s recent Chapter 78 revisions relate to enhancements to well control and construction requirements as a result of extensive drilling and completion operations in the Marcellus Shale in that state. Specific casing and cementing procedures designed to protect drinking water supplies are now codified as a result of these revisions.

8.4.5 Other States’ Regulations - Conclusion

Experience in other states is similar to that of New York as a regulator of gas drilling operations. Well control and construction, and materials handling regulations, including those pertaining to pit construction, when properly implemented and complied with, prevent environmental contamination from drilling and hydraulic fracturing activities. The reviews and surveys summarized above are informative with respect to developing enhanced mitigation measures relative to multi-well pad drilling and high-volume hydraulic fracturing. Consideration of the information presented above is reflected in Chapters 7 and 8 of this SGEIS.

39 http://www.pacode.com/secure/data/025/chapter78/chap78toc.html “Chapter 78, Oil and Gas Wells.”
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Chapter 9

Alternative Actions
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Chapter 9 – Alternative Actions

CHAPTER 9 ALTERNATIVE ACTIONS ................................................................................................................. 9-1

9.1 NO-ACTION ALTERNATIVE........................................................................................................................................ 9-1

9.2 PHASED PERMITTING APPROACH ...................................................................................................................... 9-3
  9.2.1 Inherent Difficulties in Predicting Gas Well Development Rates and Patterns ........................................... 9-4
  9.2.2 Known Tendency for Development to Occur in Phases without Government Intervention ...................... 9-4
  9.2.3 Prohibitions and Limits that Function as a Partial Phased Permitting Approach ........................................ 9-5
    9.2.3.1 Permanent Prohibitions ................................................................................................................... 9-6
    9.2.3.2 Prohibitions in Place for at Least 3 Years ......................................................................................... 9-6
    9.2.3.3 Prohibitions in Place for At Least 2 Years ......................................................................................... 9-6
  9.2.4 Permit Issuance Matched to Department Resources .................................................................................. 9-7

9.3 “GREEN” OR NON-CHEMICAL FRACTURING TECHNOLOGIES AND ADDITIVES ................................................. 9-7
  9.3.1 Environmentally-Friendly Chemical Alternatives ........................................................................................ 9-9
  9.3.2 Summary ................................................................................................................................................... 9-10

TABLES
Table 9.1 - Marcellus Permits Issued in Pennsylvania, 2007 - 2010 ........................................................................ 9-5
Chapter 9 ALTERNATIVE ACTIONS
Chapter 21 of the 1992 GEIS and the 1992 Findings Statement discussed a range of alternatives concerning oil and gas resource development in New York State that included both its prohibition and the removal of oil and gas industry regulation. Regulation as described by the 1992 GEIS was found to be the best alternative. Regulatory revisions recommended by the 1992 GEIS have been incorporated into permit conditions, which have been continuously improved since 1992.

The following alternatives to issuance of permits for high-volume hydraulic fracturing to develop the Marcellus Shale and other low permeability gas reservoirs have been reviewed for the purpose of this SGEIS:

- The denial of permits to develop the Marcellus Shale and other low-permeability gas reservoirs by horizontal drilling and high-volume hydraulic fracturing (No-action alternative);
- The use of a phased-permitting approach to developing the Marcellus Shale and other low-permeability gas reservoirs, including consideration of limiting and/or restricting resource development in designated areas; and
- The required use of “green” or non-chemical fracturing technologies and additives.

9.1 No-Action Alternative
The no-action alternative to the proposed action would be denial of permits to drill where high-volume hydraulic fracturing is proposed and a prohibition on development of the Marcellus Shale and other low-permeability reservoirs using this method. If the no-action alternative were selected, none of the potential significant adverse impacts identified in this SGEIS would occur. However, at the same time, none of the substantial economic benefits identified in Chapters 2 and 6 would occur either. Furthermore, this important energy source would not be harvested, which would be contrary to New York State and national interests. It would also contravene Article 23-0301 of the ECL where it is stated:
It is hereby declared to be in the public interest to regulate the development, production and utilization of natural resources of oil and gas in this state in such a manner as will prevent waste; to authorize and to provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas may be had, and that the correlative rights of all owners and the rights of all persons including landowners and the general public may be fully protected, and to provide in similar fashion for the underground storage of gas, the solution mining of salt and geothermal, stratigraphic and brine disposal wells.

As more fully described in Chapter 2, the Marcellus Shale, which extends from Ohio through West Virginia and into Pennsylvania and New York, is attracting attention as a significant new source of natural gas production. In New York, the Marcellus Shale is located in much of the Southern Tier, stretching from Chautauqua and Erie counties in the west to the counties of Sullivan, Ulster, Greene and Albany in the east. According to Penn State University, the Marcellus Shale is the largest known shale deposit in the world. Engelder and Lash (2008) first estimated gas-in-place to be between 168 and 500 Tcf with a recoverable estimate of 50 Tcf.\(^1\)

While it is very early in the productive life of Marcellus Shale wells, more recent estimates by Engelder (2009) using well production decline rates indicate a 50% probability that recoverable reserves could be as high as 489 Tcf.\(^2\)

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

Production and use of in-state energy resources – renewable resources and natural gas – can increase the reliability and security of our energy systems, reduce energy costs, and contribute to meeting climate change, public health and environmental objectives. Additionally, by focusing energy investments on in-state opportunities, New York can reduce the amount of dollars “exported” out of the State to pay for energy resources.\(^3\)

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\(^1\) Considine et al., 2009, p. 2.
\(^2\) Considine et al., 2009, p. 2.
\(^3\) NYS Energy Planning Board, August 2009.
The Draft Energy Plan further includes a recommendation to encourage development of the Marcellus Shale natural gas formation with environmental safeguards that are protective of water supplies and natural resources.\(^4\)

The New York State Commission on Asset Maximization recommends that “Taking into account the significant environmental considerations, the State should study the potential for new private investment in extracting natural gas in the Marcellus Shale on State-owned lands, in addition to development on private lands.” The Final report concluded that an increase in natural gas supplies would place downward pressure on natural gas prices, improve system reliability and result in lower energy costs for New Yorkers. In addition, natural gas extraction would create jobs and increase wealth to upstate landowners, and increase State revenue from taxes and land-owner leases and royalties. Development of State-owned lands could provide much needed revenue relief to the State and spur economic development and job creation in economically depressed regions of the State.\(^5\)

The no-action alternative is also not favored because most of the potential significant adverse impacts identified in this Supplement can be fully mitigated by the measures outlined in Chapter 7. Other significant adverse impacts can be partially mitigated, or are temporary in nature. A prohibition would also deny owners of mineral interests an opportunity to realize the benefit of mineral rights ownership. Accordingly, it is not a recommended alternative to the rational and controlled development proposed in this Supplement.

### 9.2 Phased Permitting Approach

The use of a phased-permitting approach to developing the Marcellus Shale and other low-permeability gas reservoirs, including consideration of limiting and restricting resource development in designated areas, was evaluated. Phased permitting would potentially place a temporal and/or geographic limit on impacts from high-volume hydraulic fracturing operations to the extent such limits were less than the annual demand for well permits. The Department’s proposed program partially adopts this alternative by restricting resource development in the NYC and Syracuse watersheds (plus buffer), public water supplies, primary aquifers and certain

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\(^4\) NYS Energy Planning Board, August 2009.

\(^5\) NYS Commission on Asset Maximization, June 2009.
state lands. In addition, restrictions and setbacks relating to development in other areas near public water supplies, principal aquifers and other resources as outlined within this SGEIS are recommended and further limit the areas with site disturbances.

The Department does not believe that resource development should be further limited by imposing an annual limit on permits issued for high-volume hydraulic fracturing operations or any other formal phasing plan. The Department believes any such annual limit would be arbitrary. Rather, the Department proposes to limit permit issuance to match the Department resources that are made available to review and approve permit applications, and to adequately inspect well pads and enforce permit conditions and regulations.

In addition, a formal phasing plan is not practical because of the inherent difficulties in predicting gas well development rates and patterns for a particular region or part of the State. In addition, the Department’s prior experience with well drilling in the State and its review of the development of high-volume hydraulic fracturing in other states suggests that well development tends to occur in phases and increase over time without a formal government mandate.

9.2.1 Inherent Difficulties in Predicting Gas Well Development Rates and Patterns

The level of impact on a regional basis will be determined by the amount of development and the rate at which it occurs. Accurately estimating this is inherently difficult due to the wide and variable range of the resource; rig, equipment and crew availability; permitting and oversight capacity; leasing, and most importantly economic factors. This holds true regardless of the type of drilling and stimulation utilized.

9.2.2 Known Tendency for Development to Occur in Phases without Government Intervention

Upon completion of this Supplement, permit issuance and drilling would start slowly as services and equipment are mobilized to the area and the Department gains experience in implementing the enhanced application review procedures. The drilling rate would ramp up over a number of years until it reaches a peak, and would then ramp down over several years until full-field development is reached.6

6 ALL Consulting, 2010, p. 6
In Pennsylvania, where the Marcellus play covers a larger area and development has already occurred, the number of permits issued has increased in recent years as indicated in Table 9.1. (The source data provides information on the number of permits issued and is not indicative of the number of wells drilled.)

<table>
<thead>
<tr>
<th>Year</th>
<th>Marcellus Permits Issued (Pennsylvania)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>99</td>
</tr>
<tr>
<td>2008</td>
<td>529</td>
</tr>
<tr>
<td>2009</td>
<td>1,991</td>
</tr>
<tr>
<td>2010</td>
<td>3,446</td>
</tr>
</tbody>
</table>

It is unknown whether the peak development rate has been reached in Pennsylvania, or how long it will take to reach full-field development in either Pennsylvania or New York. In general, however, the stages of development of a natural gas play can be grouped into five general categories: Exploration/Early Development, Moderate Development, Large-Scale Development, Post-Development Production and Closure and Reclamation. These stages are not discrete, but overlap and may occur concurrently in different areas. For example, initial production may begin during early development and well pads may be closed and reclaimed in one area as production continues elsewhere. In addition, development levels wax and wane as prices vary and technological advances occur.

9.2.3 Prohibitions and Limits that Function as a Partial Phased Permitting Approach
As set forth below, the Department’s proposed program partially adopts a phased approach because it restricts resource development in certain areas. In addition, restrictions and setbacks relating to development in other areas near public water supplies, principal aquifers and other resources as outlined within this SGEIS are recommended and further limit the areas where site disturbances would be allowed for a certain period of time.

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7 NTC Consultants, 2011, p. 36
8 Dutton and Blankenship, p. 7.
9.2.3.1 Permanent Prohibitions

The Department would not approve well pads for high-volume hydraulic fracturing:

- within the NYC and Syracuse watersheds, or within a 4,000-foot buffer around those watersheds;
- within 500 feet of private drinking water wells or domestic use springs, unless waived by the owner;
- within 100-year floodplains; and
- on certain state-owned land.

These limits function as a partial “phased” permitting approach because they prohibit activities in areas deemed to be especially sensitive.

9.2.3.2 Prohibitions in Place for at Least 3 Years

The Department would not approve well pads for high-volume hydraulic fracturing within 2,000 feet of public water supply wells, river or stream intakes or reservoirs until at least 3 years after issuance of the first permit for high-volume hydraulic fracturing. Reconsideration of this prohibition at that time would be based on actual experience and impacts associated with permit issuance outside these buffer zones. This approach functions as a partial “phased” permitting approach because it prohibits and limits activities in areas deemed to be especially sensitive where a phased and cautious approach is merited.

9.2.3.3 Prohibitions in Place for At Least 2 Years

The Department would not approve well pads for high-volume hydraulic fracturing within 500 feet of primary aquifers until at least 2 years after issuance of the first permit for high-volume hydraulic fracturing. Furthermore, during this time, the Department also would require site-specific SEQRA determinations of significance for proposed well pads within 500 feet of principal aquifers. Reconsideration of these restrictions after two years would be based on actual experience and impacts associated with permit issuance outside these buffer zones. These limits function as a partial “phased” permitting approach because they prohibit and limit activities in areas deemed to be especially sensitive where a phased and cautious approach is merited.
9.2.4 Permit Issuance Matched to Department Resources

The Department believes that any specific annual limit on the number of well permits to be issued would be essentially arbitrary and would be unnecessary given the myriad protections recommended in this SGEIS. The Department recognizes that the risk of significant adverse impacts has the potential to increase if permits were issued in excess of the Department’s capacity to adequately police such development and enforce permit conditions. Accordingly, the Department proposes to limit the number of permits it issues to match the Department resources that are made available to review and approve permit applications and to adequately inspect well pads and enforce permit conditions and regulations.

9.3 “Green” or Non-Chemical Fracturing Technologies and Additives

Hydraulic fracturing operations involve the use of significant quantities of additives/products, albeit in low concentrations, which potentially could have an adverse impact on the environment if not properly controlled. The recognition of potential hazards has motivated investigation into environmentally-friendly alternatives for hydraulic fracturing technologies and chemical additives.\(^9\)

It is important to note that use of ‘environmentally friendly’ or “green” alternatives may reduce, but not entirely eliminate, adverse environmental impacts. Therefore, further research into each alternative is warranted to fully understand the potential environmental impacts and benefits of using any of the alternatives. In addition, the claimed benefits of such alternatives would need to be evaluated in a holistic manner, considering the full lifecycle impact of the technology or chemical.\(^10\)

URS reports that the following environmentally-friendly technology alternatives have been identified as being in use in the Marcellus Shale, with other fracturing/stimulation applications or under investigation for possible use in Marcellus Shale operations:

- **Liquid CO\(_2\) alternative** – The use of a liquid CO\(_2\) and proppant mixture reduces the use of other additives [19]. CO\(_2\) vaporizes, leaving only the proppant in the fractures. The use of this technique in the United States has been limited to demonstrations or pilots [20].

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\(^9\) URS, 2009, pp. 6-1 - 6-7.
\(^10\) URS, 2009, pp. 6-1 - 6-7.
The appropriate level of environmental review for this alternative, if proposed in New York, would be determined at the time of application;

*Nitrogen-based foam alternative* – Nitrogen-based foam fracturing was used in vertical shale wells in the Appalachian Basin until recently [21]. Nitrogen gas is unable to carry appreciable amounts of proppant and the nitrogen foam was found to introduce liquid components that can cause formation damage [22]. Nitrogen-based foam fracturing is discussed starting on page 9-27 of the 1992 GEIS (Volume 1); and

*Liquefied Petroleum Gas (LPG) alternative* – The use of LPG, consisting primarily of propane, has the advantages of carbon dioxide and nitrogen cited above; additionally, LPG is known to be a good carrier of proppant due to the higher viscosity of propane gel [55]. Further, mixing LPG with natural gas does not ‘contaminate’ natural gas; and the mixture may be flowed directly into a gas pipeline and separated at the gas plant and recycled [55]. LPG’s high volatility, low weight, and high recovery potential make it a good fracturing agent. Use of LPG as a hydraulic fracturing fluid also inhibits formation damage which can occur during hydraulic fracturing with conventional fluids. Using propane not only minimizes formation damage, but also eliminates the need to source water for hydraulic fracturing, recover flowback fluids to the surface and dispose of the flowback fluids. As a result of the elimination of hydraulic fracturing source water, truck traffic to and from the wellsite would be greatly reduced. In addition, since LPG is less reactive with the formation matrix, it is therefore less likely to mobilize constituents which could increase NORM levels in the flowback fluid. LPG is discussed and addressed in the 1992 GEIS in the context of the permitting of underground gas storage wells and facilities in the State. Currently, there are three operating underground LPG storage facilities and associated wells for the injection and withdrawal of LPG, with a total storage capacity of approximately 150 million gallons of LPG. It is quite possible that these storage facilities which are located in Cortland, Schuyler and Steuben Counties could supply the LPG needed to conduct hydraulic fracturing operations at wells.

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11 Smith, 2008, p. 3.
targeting the Marcellus Shale and other low-permeability gas reservoirs should a well operator make such a proposal for the Department’s approval.

LPG fracturing technology is in limited use in Canada, and has only been used in Pennsylvania on several wells. In addition, there is only one known company that offers LPG hydraulic fracturing services, with limited equipment and crews, and service costs which are understood to be higher than those associated with water-based hydraulic fracturing. Therefore, at the current time, this technology is not mature enough to support development of the Marcellus Shale and other low-permeability gas reservoirs.

Well applications that specify and propose the use of LPG as the primary carrier fluid will be reviewed and permitted pursuant to the 1992 GEIS and Findings Statement. Horizontal and directional wells, which are part of the main subject of this SGEIS, are already in use in the Marcellus Shale. While these drilling techniques require larger quantities of water and additives per well because of the relatively longer target interval, horizontal and directional wells are considered to be more environmentally-friendly because these types of wells provide access to a larger volume of gas/oil than a typical vertical well [20, 23].

9.3.1 Environmentally-Friendly Chemical Alternatives

The use of alternative chemical additives in hydraulic fracturing is another facet to the “environmentally-friendly” development in recent years.

There are several US-based chemical suppliers who advertise “green” hydraulic fracturing additives. Examples include: Earth-friendly GreenSlurry system from Schlumberger used in both the U.K. North Sea and the Gulf of Mexico [29]; Ecosurf EH surfactants by Dow Chemicals; CleanStim by Halliburton; and “Green” Chemicals for the North Sea from BASF. The EPA has published the twelve principles of “green” chemistry and a sustainable chemistry hierarchy [30], yet these do not provide a common measure of environmental benefits to assess “green” hydraulic fracturing additives.

12 URS, 2009, pp. 6-1 - 6-7.
13 URS, 2009, pp. 6-1 - 6-7.
Although several US-based chemicals suppliers advertise “green” chemicals, there does not seem to be a US-based metric to evaluate the environmental benefits of these chemicals. The most significant environmentally conscious hydraulic fracturing operations and regulations to date are likely in the North Sea. Several countries have established criteria that define environmentally beneficial chemicals and utilize models and databases to track chemicals’ overall hazardousness against those criteria. Similar to the Department, the regulatory authorities in Europe request proprietary information from chemicals suppliers, and do not release any proprietary information into the public domain. The proprietary recipes for chemical additives are used to assess their potential hazard to the environment, and regulate their use as necessary.

In addition, the manufacturers of these “green” alternatives point out that they are not effective under some conditions. For example, where high clay content is found in the shale formation, a petroleum distillate may be needed to carry compounds designed to address the difficulties created by the clay. It is, therefore, not evident that the ability of operators to choose the most effective fluids to perform hydraulic fracturing can be reasonably circumscribed by government restrictions at this time.

9.3.2 Summary
As the Marcellus Shale and other shale plays across the United States are developed, the development and use of “green chemicals” will proceed based on the characteristics of each play and the potential environmental impacts of the development. While more research and approval criteria would be necessary to establish benchmarks for “green chemicals”, this SGEIS contains thresholds, permit conditions and review criteria to reduce or mitigate potential environmental impacts for development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. It also requires that applicants evaluate and, where feasible, use alternative additive products that may pose less risk to the environment, including water resources. It also provides for public disclosure of the additives, including additive MSDSs, used at each well. These requirements may be altered and/or expanded as clearer evidence emerges that the use of “green chemicals” can provide reasonable alternatives as the appropriate technology, criteria, and processes are developed to evaluate and produce “green chemicals.”

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14 URS, 2009, pp. 6-1 - 6-7.
15 URS, 2009, pp. 6-1 - 6-7.
Chapter 10

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

CHAPTER 10 REVIEW OF SELECTED NON-ROUTINE INCIDENTS IN PENNSYLVANIA ...........................................10-1

10.1 GAS MIGRATION – SUSQUEHANNA AND BRADFORD COUNTIES ................................................................. 10-1
   10.1.1 Description of Incidents .................................................................................................................................. 10-1
   10.1.2 New York Mitigation Measures Designed to Prevent Gas Migration Similar to the Pennsylvania
   Incidents...................................................................................................................................................................... 10-1

10.2 FRACTURING FLUID RELEASES – SUSQUEHANNA AND BRADFORD COUNTIES ............................................. 10-2
   10.2.1 Description of Incidents .................................................................................................................................. 10-2
   10.2.2 New York Mitigation Measures Designed to Prevent Fracturing Fluid Releases........................................... 10-3

10.3 UNCONTROLLED WELLBORE RELEASE OF FLOWBACK WATER AND BRINE – CLEARFIELD COUNTY ............. 10-4
   10.3.1 Description of Incident ...................................................................................................................................... 10-4
   10.3.2 New York Mitigation Measures Designed to Prevent Uncontrolled Wellbore Release of Flowback Water
   and Brine.................................................................................................................................................................... 10-4

10.4 HIGH TOTAL DISSOLVED SOLIDS (TDS) DISCHARGES – MONONGAHELA RIVER .............................................. 10-4
   10.4.1 Description of Incidents ...................................................................................................................................... 10-4
   10.4.2 New York Mitigation Measures Designed to Prevent High In-Stream TDS...................................................... 10-4
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More than 3,000 Marcellus wells have been drilled in Pennsylvania since 2005, most of which have been or will be developed by high-volume hydraulic fracturing. A number of regulatory violations, non-routine incidents and enforcement cases have been widely publicized. Some of them are briefly described below, with information about the measures currently required in New York or those that the Department proposes to require that are designed to prevent similar problems if high-volume hydraulic fracturing is permitted in the Empire State.

10.1 Gas Migration – Susquehanna and Bradford Counties

10.1.1 Description of Incidents
In 2009, the appearance of methane in water wells in an area in Dimock Township, Susquehanna County, was attributed to excessive pressures and improperly or insufficiently cemented casings at nearby Marcellus wells.\(^1\) Numerous occurrences of methane migration into residential water wells during 2010 in Tuscarora, Terry, Monroe, Towanda and Wilmot Townships, Bradford County were attributed to the failure to properly case and cement wells.\(^2\)

10.1.2 New York Mitigation Measures Designed to Prevent Gas Migration Similar to the Pennsylvania Incidents
The potential for water wells to be impacted by methane migration associated with gas well construction was a high-profile concern in Chautauqua County, New York, in the 1980s. Then-Commissioner Henry Williams addressed the situation in a decision issued after a public hearing held in Jamestown. That decision, which among other things directed staff to (1) require wells in primary and principal aquifers to be cemented to surface and (2) prohibit excessive annular pressure, is the foundation of New York’s current well construction requirements. The 1992 GEIS adopted minimum casing and cement practices, which are augmented as necessary to address site-specific conditions and incorporated as conditions of every well permit the Department issues. Additionally, the Department does not issue a permit to drill any well until

\(^1\) PADEP, 2009, p. 3.
\(^2\) PADEP, 2011, p. 9.
the proposed wellbore design for that specific well and location has been reviewed by
Department staff and deemed satisfactory. Permits are not issued for improperly designed wells,
and for high-volume hydraulic fracturing, as-built wellbore construction would be verified as
described in Chapter 7. Additionally, intermediate casing would be required, unless clearly
justified otherwise, with the setting depths of both surface and intermediate casing determined by
site-specific conditions.

The effectiveness of the Department’s well construction approach with respect to gas migration
is demonstrated by the rarity of gas migration incidents in New York. The most recent incident
occurred 15 years prior to the date of this document, in 1996, and resulted not from well
construction but from the operator reacting improperly to a problem encountered while drilling.
More than 3,000 wells have been drilled under ECL Article 23 permits since 1996 without
another occurrence.

As noted in the 1992 GEIS and in Section 4.7 of this document, methane is naturally present in
water wells in many locations in New York, for many reasons unrelated to gas well drilling.
This is a fact which must be evaluated and considered when a gas drilling impact is suspected as
a source of methane in water wells.

10.2 Fracturing Fluid Releases – Susquehanna and Bradford Counties

10.2.1 Description of Incidents
In 2009, three fracturing fluid releases occurred at a single well pad in Dimock Township,
Susquehanna County. The releases resulted from equipment failures when the pressure rating of
some piping components on the well pad were exceeded while the operator was mixing and
pumping fluid for hydraulic fracturing. This resulted from a combination of pressure
fluctuations while pumping and a significant elevation difference between the fresh water tanks
and the well pad. The fresh water tanks were located 240 feet above the well pad and the mixing
area was 190 feet above and over 2,000 feet away from the well pad.³

On April 19, 2011, an uncontrolled flow of hydraulic fracturing fluid occurred during fracture
stimulation of Chesapeake Energy’s Atlas 2H well in LeRoy Township, Bradford County. The

³ Cabot Oil & Gas Corporation, 2009.
Department’s Commissioner visited this site on June 16, 2011, and was briefed by officials from
the Pennsylvania Department of Environmental Protection, Chesapeake Energy, and the
Bradford County Soil and Water Conservation District. At the briefing and tour of the well pad,
it was learned that a failure occurred at a valve flange connection to the wellhead, causing fluid
to be discharged from the wellhead at high pressure. Approximately 60,000 gallons of fluid
were discharged to the well pad, of which 10,000 gallons flowed over the top of the containment
berms. A portion of this fluid made its way into an unnamed tributary of Towanda Creek. The
wellhead failure is under investigation to determine the precise cause of the breach. The
wellhead was pressure-tested after installation and after each hydraulic fracturing stage prior to
the breach. According to Chesapeake officials, it passed all tests. The discharge of fluid from
the well pad was caused by the failure of stormwater controls on the well pad due to
extraordinary precipitation and other factors.4

10.2.2 New York Mitigation Measures Designed to Prevent Fracturing Fluid Releases
The site layout in Dimock was unusual and, if proposed in New York, would be flagged during
the Department’s review of the application materials, which always include maps and a pre-
permitting site inspection. Such a layout would not be approved by the Department without site-
specific permit conditions designed to address the risks associated with hillside locations. Steep
slopes above surface water bodies reduce the time available to respond to a release or spill, and
in New York locations on steep slopes above potential drinking water supplies are not eligible
for authorization under a general stormwater permit.

It is important to note that in both cases it was mixed fracturing fluid that was released, not
undiluted additives. Supplementary permit conditions for high-volume hydraulic fracturing in
New York will require pressure testing of fracturing equipment components with fresh water
prior to introducing additives.

4 Although described in press accounts as a “blowout,” such terminology is not technically correct because the
source of pressure was the fracturing operations on the surface. A blowout is an uncontrolled intrusion of fluid
under high pressure into the wellbore, from the rock formation.
10.3 **Uncontrolled Wellbore Release of Flowback Water and Brine – Clearfield County**

10.3.1 *Description of Incident*
In 2010 an operator in Lawrence Township, Clearfield County, lost control of a wellbore during post-fracturing cleanout activities, releasing natural gas, flowback water and brine into the environment. It was determined that blowout prevention equipment was inadequate and that certified well-control personnel were not on-site.\(^5\)

10.3.2 *New York Mitigation Measures Designed to Prevent Uncontrolled Wellbore Release of Flowback Water and Brine*
Proposed supplementary permit conditions for high-volume hydraulic fracturing would require pressure testing of blowout prevention equipment, the use of at least two mechanical barriers that can be tested, the use of specialized equipment designed for entering the wellbore when pressure is anticipated and the on-site presence of a certified well control specialist.

10.4 **High Total Dissolved Solids (TDS) Discharges – Monongahela River**

10.4.1 *Description of Incidents*
During seasonal low-flow conditions in the Monongahela River in 2008, an increase in gas-drilling wastewater discharges may have provided the TDS “tipping point” for the Monongahela River. At the time, many rivers in that state were unable to assimilate new high-TDS waste streams because they were already impaired by pre-existing elevated TDS levels from various historic practices, and Pennsylvania’s regulations did not include a surface water quality standard for TDS. In the three years since these events occurred, Pennsylvania has enacted new regulations that restrict discharge of high-TDS wastewater associated with Marcellus Shale development. The PADEP has also requested that Marcellus operators discontinue discharging flowback water to facilities that are “grandfathered” from the new requirements. Additionally, as discussed in Section 1.1.1, operators in Pennsylvania are now reusing flowback water for subsequent fracturing operations.

10.4.2 *New York Mitigation Measures Designed to Prevent High In-Stream TDS*
New York’s water quality standards include an in-stream limit for TDS and SPDES permits include effluent limitations based on a stream’s assimilative capacity. As described in Chapters

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\(^5\) PADEP, 2010.
and in Appendix 22, the Department has a robust permitting and approval process in place to address any proposals to discharge flowback water or production brine to wastewater treatment plants. Additionally, the Department anticipates that operators will favor reusing flowback water for subsequent fracturing operations as they are now doing in Pennsylvania.
Chapter 11

Summary of Potential Impacts and Mitigation Measures

Revised Draft
Supplemental Generic Environmental Impact Statement
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Chapter 11 – Summary of Potential Impacts and Mitigation Measures

CHAPTER 11 SUMMARY OF POTENTIAL IMPACTS AND MITIGATION MEASURES ............................................. 11-1

TABLES
Table 11.1 - Summary of Potential Impacts and Proposed Mitigation Measures (New July 2011) ......................... 11-2
Chapter 11 SUMMARY OF POTENTIAL IMPACTS AND MITIGATION MEASURES
A complete description of the potential impacts associated with horizontal drilling and high-volume hydraulic fracturing is presented in Chapter 6. The mitigation measures proposed to minimize those impacts are discussed in Chapter 7, while the associated Supplementary permit conditions are provided in Appendix 10. Additionally, Chapter 8 includes descriptions of other applicable state and federal regulatory programs which have authority over activities associated with natural gas well development. Table 11.1 below provides a summary of the potential impacts and proposed mitigation measures.
<table>
<thead>
<tr>
<th>RESOURCE</th>
<th>IMPACT</th>
<th>SGEIS Section</th>
<th>SGEIS PP</th>
<th>GES-SEC</th>
<th>MITIGATING MEASURE</th>
<th>SGEIS Section</th>
<th>SGEIS PP</th>
<th>GES-SEC</th>
<th>GES-PP</th>
</tr>
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<tbody>
<tr>
<td>Water resources</td>
<td>Depletion of water supply in streams.</td>
<td>6.1.1.1</td>
<td></td>
<td></td>
<td>Requires determination of and adherence to passby flow for each surface water proposed for withdrawals using the Natural Flow Regime method.</td>
<td>7.1.1.4</td>
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<td></td>
<td>Reduced stream flow and degradation of a stream’s best use.</td>
<td>6.1.1.2</td>
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<td>Same as above.</td>
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<td></td>
<td>Loss or impairment of aquatic habitat, aquatic ecosystems, or aquifer recharge ability in surface waters.</td>
<td>6.1.1.3-6</td>
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<td>Same as above.</td>
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<td></td>
<td>Revises determination of and adherence to passby flow for each surface water proposed for withdrawals using the Natural Flow Regime method.</td>
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<td>Long-term damage to groundwater resources</td>
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<td>6.1.1.5</td>
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<td>Requires determination of and adherence to passby flow for each surface water proposed for withdrawals using the Natural Flow Regime method.</td>
<td>7.1.1.5</td>
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<td>Cumulative surface water withdrawal impacts.</td>
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<td>6.1.1.7</td>
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<td>Addressed by individual passby flow determinations as above.</td>
<td>7.1.1.6</td>
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<td>Contamination of surface and/or subsurface waters from stormwater runoff.</td>
<td></td>
<td>6.1.2</td>
<td>16.8.3,a,b</td>
<td>16-12.15</td>
<td>Requires determination of and adherence to passby flow for each surface water proposed for withdrawals using the Natural Flow Regime method.</td>
<td>7.1.2</td>
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<td></td>
<td>Requires application for and coverage under the General Permit before commencement of operations.</td>
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<td></td>
<td>Authorizes permit conditions on a case-by-case basis regarding erosion and sediment control in watersheds of drinking water reservoirs.</td>
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<td>Specifies a reclamation timetable of 45 days following cessation of drilling.</td>
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<td></td>
<td>Requires a Stream Disturbance Permit when project is w/in 50' of a protected stream. Authorizes permit conditions on a case-by-case basis regarding stream crossings, access roads, EPSC measures, and reclamation.</td>
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<td></td>
<td>Well pads for high-volume hydraulic fracturing prohibited within 2000' of public drinking water wells, river or stream intakes and reservoirs.</td>
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<td></td>
<td>Specifies setback distances from structures, surface waters, public/private water wells, and water supply springs.</td>
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Revised Draft SGEIS 2011, Page 11-2
<table>
<thead>
<tr>
<th>RESOURCE</th>
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<th>SGEIS PP.</th>
<th>MITIGATING MEASURE</th>
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</thead>
<tbody>
<tr>
<td>Water resources</td>
<td>Contamination of surface waters, groundwater, or drinking water aquifers from chemical, fuel, or lubricant spills (including drilling and fracturing fluids). (cont.)</td>
<td>16.3</td>
<td>16.16.19</td>
<td>Requires reporting in EAF addendum of location of fuel tanks relative to surface waters, wetlands, drinking water wells, and aquifer boundaries.</td>
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<td>6.1.3</td>
<td>16.B.4.a,c</td>
<td>No well pads within 500' of a private water well, unless waived by the landowner.</td>
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<td>7.1.3.1</td>
<td>Requires spill response and cleanup to be addressed in the SWPPP by inclusion of Best Management Practices to control, remediate, and clean up spills.</td>
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<td>7.1.3.2</td>
<td>Individual crew member responsibilities must be posted for well-control. Blowout Preventers (BOPs) must be adequately sized and tested.</td>
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<td>7.1.3.3</td>
<td>Affords DEC option to implement location-specific HVHF fluid management restrictions and permit conditions.</td>
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<td>7.1.3.4</td>
<td>Hydraulic fracturing fluid additives should be required by permit condition to be placed in lined containment areas.</td>
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<td>7.1.3.4</td>
<td>Identification of a spill response team and employee training on proper spill prevention and response techniques.</td>
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<td>7.1.3.4</td>
<td>Requires a closed-tank system for flowback water handled at the wellpad.</td>
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<td>7.1.3.4</td>
<td>Requires reporting EAF addendum on quantity, worthiness, volume, and location of tanks to accept flowback water.</td>
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<td>7.1.3.4</td>
<td>Promote reuse of flowback water.</td>
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<td>8.2.1.2</td>
<td>Requires operators to consider less toxic alternative hydraulic fracturing fluid additives.</td>
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<td>7.1.3.4</td>
<td>Limits duration of fluid impoundment after permanent/temporary suspension of drilling/hydraulic fracturing.</td>
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<td>7.1.3.4</td>
<td>Specifies continuous supervision of fluid transfer activities.</td>
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<td>Water resources (cont.)</td>
<td>Contamination of groundwater/aquifers from natural gas, drilling fluids, or HVHF fluids in the wellbore.</td>
<td>Specifies spill prevention and response BMPs to be addressed in SWPPP. At least two vacuum trucks must be on standby at the wellsites during the flowback phase.</td>
<td>7.1.3.4</td>
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<td>Requires dikes around oil storage tanks.</td>
<td>17.B.2.f</td>
<td>17-7</td>
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<td>References requirement for BOPs on wells in NY state.</td>
<td>17.C.1.i</td>
<td>17-12</td>
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<td>Subjects operators to enforcement actions and penalties upon release of flowback fluids onto the ground.</td>
<td>17.C.1.m</td>
<td>17-12</td>
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<td>Affords right to the department to require fluid-level monitors on tanks where repeated overflows have occurred.</td>
<td>17.D.2.c</td>
<td>17-16</td>
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<td>Specifies frequency and character of sampling, testing, and reporting of nearby private water wells before, during, and after drilling and HVHF activity.</td>
<td>7.1.4.1</td>
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<td>Affords DEC the right to curtail or modify operations when a well complaint and a non-routine wellpad incident coincide.</td>
<td>7.1.4.1</td>
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<td>No well pads for high-volume hydraulic fracturing within the boundaries of a primary aquifer.</td>
<td>7.1.3.5</td>
<td>17.C.1.q</td>
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<td>No well pads for high-volume hydraulic fracturing permitted within 500' of a primary aquifer.</td>
<td>7.1.3.5</td>
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<td>No well pads for high-volume hydraulic fracturing within 500' of a principal aquifer without site-specific SEQRA review and an individual SPDES permit</td>
<td>7.1.3.5</td>
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<td>Requires operator to test private water wells</td>
<td>7.1.4.1</td>
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<td>Specifies permit conditions for more stringent casing construction and cementing, reporting of well information, and testing of cement job for HVHF wells.</td>
<td>7.1.4.2</td>
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<td>Requires departmental notification prior to surface casing cementing.</td>
<td>7.1.4.2</td>
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<td>Specifies constant venting of annulus to prevent pressure buildup, unless the annular gas is to be produced, in which case the equipment and production pressure must receive departmental approval.</td>
<td>7.1.4.3</td>
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<td><strong>Water resources (cont.)</strong></td>
<td>Contamination of groundwater/aquifers from natural gas, drilling fluids, or HVHF fluids in the wellbore. (cont.)</td>
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<td>Contamination of aquifers/groundwater from hydraulic fracturing</td>
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<td><strong>Water resources</strong> (cont.)</td>
<td>Contamination of surface or subsurface water with HVHF or drilling fluids from container leakage, structural failure, or improper transportation.</td>
<td>6.1.6</td>
<td>16.B.3.b,c</td>
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<td><strong>Water resources</strong> (cont.)</td>
<td>Contamination of soil or water from improper disposal, transportation, or release of waste solids or fluids (including HVHF flowback).</td>
<td>6.1.6-9</td>
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<td><strong>Water resources</strong> (cont.)</td>
<td>Contamination of soil or water from improper disposal/release of waste solids or fluids (including HVHF flowback) into the environment. (cont.)</td>
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